ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 51, 72, 73, 74, 77, 78 and 96

[OAR–2003–0053; FRL–7885–9]

RIN 2060–AL76

Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Revisions to Acid Rain Program; Revisions to the NO_X SIP Call

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: In today's action, EPA finds that 28 States and the District of Columbia contribute significantly to nonattainment of the national ambient air quality standards (NAAQS) for fine particles ($PM_{2.5}$) and/or 8-hour ozone in downwind States. The EPA is requiring these upwind States to revise their State implementation plans (SIPs) to include control measures to reduce emissions of sulfur dioxide (SO_2) and/or nitrogen oxides (NO_X). Sulfur dioxide is a precursor to $PM_{2.5}$ formation, and NO_X is a precursor to both ozone and $PM_{2.5}$ formation. Reducing upwind precursor emissions will assist the downwind $PM_{2.5}$ and 8-hour ozone nonattainment areas in achieving the NAAQS. Moreover, attainment will be achieved in a more equitable, cost-effective manner than if each nonattainment area attempted to achieve attainment by implementing local emissions reductions alone.

Based on State obligations to address interstate transport of pollutants under section 110(a)(2)(D) of the Clean Air Act (CAA), EPA is specifying statewide emissions reduction requirements for SO_2 and NO_X. The EPA is specifying that the emissions reductions be implemented in two phases. The first phase of NO_X reductions starts in 2009 (covering 2009–2014) and the first phase of SO_2 reductions starts in 2010 (covering 2010–2014); the second phase of reductions for both NO_X and SO_2 starts in 2015 (covering 2015 and thereafter). The required emissions reductions requirements are based on controls that are known to be highly cost effective for electric generating units (EGUs).

Today's action also includes model rules for multi-State cap and trade programs for annual SO_2 and NO_X emissions for $PM_{2.5}$ and seasonal NO_X emissions for ozone that States can choose to adopt to meet the required emissions reductions in a flexible and cost-effective manner.

Today's action also includes revisions to the Acid Rain Program regulations under title IV of the CAA, particularly the regulatory provisions governing the SO_2 cap and trade program. The revisions are made because they streamline the operation of the Acid Rain SO_2 cap and trade program and/or facilitate the interaction of that cap and trade program with the model SO_2 cap and trade program included in today's action. In addition, today's action provides for the NO_X SIP Call cap and trade program to be replaced by the CAIR ozone-season NO_X trading program.

DATES: The effective date of today's action, except for the revisions to 40 CFR parts 72, 73, 74, and 77 of the Acid Rain Program regulations, is July 11, 2005. States must submit to EPA for approval enforceable plans for complying with the requirements of this rule by September 11, 2006. The effective date for today's revisions to 40 CFR parts 72, 73, 74, and 77 of the Acid Rain Program regulations is July 1, 2006.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. OAR–2003–0053. All documents in the docket are listed in the EDOCKET index at *http://www.epa.gov/edocket*. Although listed in the index, some information is not publicly available, *i.e.*, Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in EDOCKET or in hard copy at the EPA Docket Center, EPA West, Room B102, 1301 Constitution Avenue, NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For general questions concerning today's action, please contact Carla Oldham, U.S. EPA, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, Mail Code C539–02, Research Triangle Park, NC, 27711, telephone (919) 541–3347, e-mail at *oldham.carla@epa.gov*. For legal questions, please contact Sonja Petersen, U.S. EPA, Office of General Counsel, Mail Code 2344A, 1200 Pennsylvania Avenue, NW., Washington, DC, 20460, telephone (202) 564–4079, e-mail at *petersen.sonja@epa.gov*. For questions regarding air quality analyses, please contact Norm Possiel, U.S. EPA, Office of Air Quality Planning and Standards, Emissions Monitoring and Analysis Division, Mail Code D243–01, Research Triangle Park, NC, 27711, telephone (919) 541–5692, e-mail at *possiel.norm@epa.gov*. For questions regarding the EGU cost analyses, emissions inventories, and budgets, please contact Roman Kramarchuk, U.S. EPA, Office of Atmospheric Programs, Clean Air Markets Division, Mail Code 6204J, 1200 Pennsylvania Avenue, NW., Washington, DC, 20460, telephone (202) 343–9089, e-mail at *kramarchuk.roman@epa.gov*. For questions regarding statewide emissions inventories, please contact Ron Ryan, U.S. EPA, Office of Air Quality Planning and Standards, Emissions Monitoring and Analysis Division, Mail Code D205–01, Research Triangle Park, NC, 27711, telephone (919) 541–4330, e-mail at *ryan.ron@epa.gov*. For questions regarding emissions reporting requirements, please contact Bill Kuykendal, U.S. EPA, Office of Air Quality Planning and Standards, Emissions Monitoring and Analysis Division, Mail Code D205–01, Research Triangle Park, NC, 27711, telephone (919) 541–5372, e-mail at *kuykendal.bill@epa.gov*. For questions regarding the model cap and trade programs, please contact Sam Waltzer, U.S. EPA, Office of Atmospheric Programs, Clean Air Markets Division, Mail Code 6204J, 1200 Pennsylvania Avenue, NW., Washington, DC, 20460, telephone (202) 343–9175, e-mail at *waltzer.sam@epa.gov*. For questions regarding analyses required by statutes and executive orders, please contact Linda Chappell, U.S. EPA, Office of Air Quality Planning and Standards, Air Quality Strategies and Standards Division, Mail Code C339–01, Research Triangle Park, NC, 27711, telephone (919) 541–2864, e-mail at *chappell.linda@epa.gov*. For questions regarding the Acid Rain Program regulation revisions, please contact Dwight C. Alpern, U.S. EPA, Office of Atmospheric Programs, Clean Air Markets Division, Mail Code 6204J, 1200 Pennsylvania Avenue, NW., Washington, DC, 20460, telephone (202) 343–9151, e-mail at *alpern.dwight@epa.gov*.

SUPPLEMENTARY INFORMATION:

Regulated Entities

Except for the revisions to the Acid Rain Program regulations, this action does not directly regulate emissions sources. Instead, it requires States to revise their SIPs to include control measures to reduce emissions of NO_X and SO_2. The emissions reductions requirement assigned to the States are based on controls that are known to be highly cost effective for EGUs.

Entities potentially regulated by the revisions to the Acid Rain Program regulations in this action are fossil-fuel-fired boilers, turbines, and internal combustion engines, including those that serve generators producing electricity, generate steam, or cogenerate electricity and steam. Regulated categories and entities include:

Category	[1] NAICS code	Examples of potentially regulated entities
Industry	221112 and others	Electric service providers, boilers, turbines, and internal combustion engines from a wide range of industries.
Federal government	22112[2]	Fossil fuel-fired electric utility steam generating units owned by the Federal government.
State/local/Tribal government.	22112[2] 921150	Fossil fuel-fired electric utility steam generating units owned by municipalities. Fossil fuel-fired electric utility steam generating units in Indian Country.

[1] North American Industry Classification System.
[2] Federal, State, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by the revisions to the Acid Rain Program regulations in this action. This table lists the types of entities that EPA is aware could potentially be regulated. Other types of entities not listed in the table could also be regulated. To determine whether your facility is regulated, you should carefully examine the applicability criteria in 40 CFR 72.6 and 74.2 and the exemptions in 40 CFR 72.7 and 72.8. If you have questions regarding the applicability of the revisions to the Acid Rain Program regulations in this action to a particular entity, consult persons listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Web Site for Rulemaking Information

The EPA has also established a Web site for this rulemaking at *http://www.epa.gov/cleanairinterstaterule/* or *http://www.epa.gov/cair/* (formerly at *http://www.epa.gov/interstateairquality/*) which includes the rulemaking actions and certain other related information that the public may find useful.

Outline

I. Overview

By notice of proposed rulemaking dated January 30, 2004 and by notice of supplemental rulemaking dated June 10, 2004, EPA proposed to find that certain States must reduce emissions of SO_2 and/or NO_X because those emissions contribute significantly to downwind areas in other States that are not meeting the annual $PM_{2.5}$ NAAQS or the 8-hour ozone NAAQS.[1] Today, EPA takes final action requiring 28 States and the District of Columbia to adopt and submit revisions to their State implementation plans (SIPs), under the requirements of CAA section 110(a)(2)(D), that would eliminate specified amounts of SO_2 and/or NO_X emissions.

Each State may independently determine which emissions sources to subject to controls, and which control measures to adopt. The EPA's analysis indicates that emissions reductions from electric generating units (EGUs) are highly cost effective, and EPA encourages States to adopt controls for EGUs. States that do so must place an enforceable limit, or cap, on EGU emissions (see section VII for discussion). The EPA has calculated the amount of each State's EGU emissions cap, or budget, based on reductions that EPA has determined are highly cost effective. States may allow their EGUs to participate in an EPA-administered cap and trade program as a way to reduce the cost of compliance, and to provide compliance flexibility. The cap and trade programs are described in more detail in section VIII.

The EPA estimates that today's action will reduce SO_2 emissions by 3.5 million tons [2] in 2010 and by 3.8 million tons in 2015; and would reduce annual NO_X emissions by 1.2 million tons in 2009 and by 1.5 million tons in 2015.[2] (These numbers are for the 23 States and the District of Columbia that are affected by the annual SO_2 and NO_X requirements of CAIR.) If all the affected States choose to achieve these reductions through EGU controls, then EGU SO_2 emissions in the affected States would be capped at 3.6 million tons in 2010 and 2.5 million tons in 2015[4]; and EGU annual NO_X emissions would be capped at 1.5 million tons in 2009 and 1.3 million tons in 2015. The EPA estimates that the required SO_2 and NO_X emissions reductions would, by themselves, bring into attainment 52 of the 79 counties that are otherwise projected to be in nonattainment for $PM_{2.5}$ in 2010, and 57 of the 74 counties that are otherwise projected to be in nonattainment for $PM_{2.5}$ in 2015. The EPA further estimates that the required NO_X emissions reductions would, by themselves, bring into attainment 3 of the 40 counties that are otherwise projected to be in nonattainment for 8-hour ozone in 2010, and 6 of the 22 counties that are projected to be in nonattainment for 8-hour ozone in 2015. In addition, today's rule will improve $PM_{2.5}$ and 8-hour ozone air quality in the areas that would remain

[1] "Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Interstate Air Quality Rule); Proposed Rule," (69 FR 4566, January 30, 2004) (NPR or January Proposal); "Supplemental Proposal for the Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Proposed Rule," (69 FR 32684, June 10, 2004) (SNPR or Supplemental Proposal).

[2] These data are from EPA's most recent IPM modeling reflecting the final CAIR of today's notice. These results may differ slightly from those appearing in elsewhere in this preamble and the RIA, which were largely based upon a model run that included Arkansas, Delaware, and New Jersey in the annual CAIR requirements and also did not apply an ozone season cap on any States (the modeling was completed before EPA had determined the final scope of CAIR because of the length of time necessary to perform air quality modeling).

[3] These values represent reductions from future projected emissions without CAIR. In 2010 CAIR will reduce SO_2 by 4.3 million tons from 2003 levels and in 2015 it will reduce SO_2 emissions by 5.4 million tons from 2003 levels. In 2009, CAIR will reduce NO_X levels by 1.7 million tons from 2003 levels and in 2015 it will reduce NO_X levels by 2.0 million tons from 2003 levels.

[4] It should be noted that the banking provisions of the cap and trade program which encourage sources to make significant reductions before 2010 also allow sources to operate above these cap levels until all of the banked allowances are used, therefore EPA does not project that these caps will be met in 2010 or 2015.

nonattainment for those two NAAQS after implementation of today's rule. Because of today's rule, the States with those remaining nonattainment areas will find it less burdensome and less expensive to reach attainment by adopting additional local controls. The Clean Air Interstate Rule (CAIR) will also reduce $PM_{2.5}$ and 8-hour ozone levels in attainment areas, providing significant health and environmental benefits in all areas of the eastern US.

The EPA's CAIR and the previously promulgated NO_X SIP Call reflect EPA's determination that the required SO_2 and NO_X reductions are sufficient to eliminate upwind States' significant contribution to downwind nonattainment. These programs are not designed to eliminate all contributions to transport, but rather to balance the burden for achieving attainment between regional-scale and local-scale control programs.

The EPA conducted a regulatory impact analysis (RIA), entitled ''Regulatory Impact Analysis for the Final Clean Air Interstate Rule (March 2005)'' that estimates the annual private compliance costs (1999$) of $2.4 billion for 2010 and $3.6 billion for 2015, if all States make the required emissions reductions through the power industry. Additionally, the RIA includes a benefit-cost analysis demonstrating that substantial net economic benefits to society will be achieved from the emissions reductions required in this rulemaking. For determination of net benefits, the above private costs were converted to social costs that are lower since transfer payments, such as taxes, are removed from the estimates. The EPA analysis shows that today's action inclusive of the concurrent New Jersey and Delaware proposal will generate annual net benefits of approximately $71.4 or $60.4 billion in 2010 and $98.5 or $83.2 billion in 2015.[5] These alternate net benefit estimates reflect differing assumptions about the social discount rate used to estimate the benefits and costs of the rule. The lower estimates reflect a discount rate of 7 percent and the higher estimates a discount rate of 3 percent. In 2015, the total annual quantified benefits are $101 or $86.3 billion and the annual social costs are $2.6 or $3.1 billion—benefits outweigh costs in 2015 by a ratio of 39 to 1 or 28 to 1 (3 percent and 7 percent discount rates, respectively). These estimates do not include the value of benefits or costs that we cannot monetize.

In 2015, we estimate that PM-related annual benefits include approximately 17,000 fewer premature fatalities, 8,700 fewer cases of chronic bronchitis, 22,000 fewer non-fatal heart attacks, 10,500 fewer hospitalization admissions (for respiratory and cardiovascular disease combined) and result in significant reductions in days of restricted activity due to respiratory illness (with an estimate of 9.9 million fewer minor restricted activity days) and approximately 1,700,000 fewer work loss days. We also estimate substantial health improvements for children from reduced upper and lower respiratory illness, acute bronchitis, and asthma attacks.

Ozone health-related benefits are expected to occur during the summer ozone season (usually ranging from May to September in the Eastern U.S.). Based upon modeling for 2015, annual ozone-related health benefits are expected to include 2,800 fewer hospital admissions for respiratory illnesses, 280 fewer emergency room admissions for asthma, 690,000 fewer days with restricted activity levels, and 510,000 fewer days where children are absent from school due to illnesses.

In addition to these significant health benefits, the rule will result in ecological and welfare benefits. These benefits include visibility improvements; reductions in acidification in lakes, streams, and forests; reduced eutrophication in water bodies; and benefits from reduced ozone levels for forests and agricultural production.

Several other documents containing detailed explanations of other key elements of today's rule are also included in the docket. These include a detailed explanation of how EPA calculated the State-by-State EGU emissions budgets, and a detailed explanation of the air quality modeling analyses which support this rule.[6] Responses to comments that are not addressed in the preamble to today's rule are included in a separate document.[7]

The remaining sections of the preamble describe the final CAIR requirements and our responses to comments on many of the most important features of the CAIR. Section II, ''EPA's Analytical Approach,'' summarizes EPA's overall analytical approach and responds to general comments on that approach. Section III, ''Why Does This Rule Focus on SO_2 and NO_X, and How Were Significant Downwind Impacts Determined?,'' outlines the rationale for the CAIR focus on SO_2 and NO_X, which are precursors that contribute to $PM_{2.5}$ (SO_2, NO_X) or ozone (NO_X) transport, and the analytic approach EPA used to determine which States had large enough downwind ambient air quality impacts to become subject to today's requirements. Section IV, ''What Amounts of SO_2 and NO_X Emissions Did EPA Determine Should Be Reduced?,'' describes EPA's methodology for determining the amounts of SO_2 and NO_X emissions reductions required under today's rule. Section V, ''Determination of State Emissions Budgets,'' describes how EPA determined the State-by-State emissions reductions requirements and, in the event States elect to control EGUs, the State-by-State EGU emissions budgets. Section VI, ''Air Quality Modeling Approach and Results,'' describes the technical aspects of the air quality modeling and summarizes the numerical results of that modeling. Section VII, ''SIP Criteria and Emissions Reporting Requirements,'' describes the SIP submission date and other SIP requirements associated with the emissions controls that States might adopt. Section VIII, ''NO_X and SO_2 Model Cap and Trade Programs,'' describes the EPA administered cap and trade programs that States electing to control emissions from EGUs are encouraged to adopt. Section IX, ''Interactions with Other Clean Air Act Requirements,'' discusses how this rule interacts with the acid rain provisions in CAA title IV, the NO_X SIP Call, the best available retrofit technology (BART) requirements, and other CAA or regulatory requirements. Finally, section X, ''Statutory and Executive Order Reviews,'' describes the applicability of various administrative requirements for today's rule and how EPA addressed these requirements.

A. What Are the Central Requirements of This Rule?

In today's action, we establish SIP requirements for the affected upwind States under CAA section 110(a)(2). Clean Air Act section 110(a)(2)(D) requires SIPs to contain adequate provisions prohibiting air pollutant emissions from sources or activities in those States that contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to a NAAQS. Based on air

[5] Benefit and cost estimates reflect annual SO_2 and NO_X controls for Arkansas that are not a part of the final CAIR program. For this reason, these estimates are slightly overstated.

[6] Technical support document: ''Regional and State SO_2 and NO_X Emissions Budgets'' is included in the docket.

Technical support document: ''Air Quality Modeling'' is included in the docket.

[7] ''Response to Significant Comments on the Proposed Clean Air Interstate Rule'' is included in the docket.

quality modeling analyses and cost analyses, EPA has concluded that SO_2 and NO_X emissions in certain States in the eastern part of the country, through the phenomenon of air pollution transport,[8] contribute significantly to downwind nonattainment, or interfere with maintenance, of the $PM_{2.5}$ and 8-hour ozone NAAQS. The EPA is requiring SIP revisions in 28 States and the District of Columbia to reduce SO_2 and/or NO_X emissions, which are important precursors of $PM_{2.5}$ (NO_X and SO_2) and ozone (NO_X).

The 23 States along with the District of Columbia that must reduce annual SO_2 and NO_X emissions for the purposes of the $PM_{2.5}$ NAAQS are: Alabama, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin.

The 25 States along with the District of Columbia that must reduce NO_X emissions for the purposes of the 8-hour ozone NAAQS are: Alabama, Arkansas, Connecticut, Delaware, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin. In addition to making the findings of significant contribution to nonattainment or interference with maintenance, EPA is requiring each State to make specified amounts of SO_2 and/or NO_X emissions reductions to eliminate their significant contribution to downwind States. The affected States and the District of Columbia are required to adopt and submit the required SIP revision with the necessary control measures by 18 months from the signature date of today's rule.

The emissions reductions requirements are based on controls that EPA has determined to be highly cost effective for EGUs. However, States have the flexibility to choose the measures to adopt to achieve the specified emissions reductions. If the State chooses to control EGUs, then it must establish a budget—that is, an emissions cap—for those sources. Today's rule defines the EGU budgets for each affected State if a State chooses to control only EGUs. The rule also explains the emission reduction requirements if a State chooses to achieve some or all of its required emission reductions by controlling sources other than EGUs. Due to feasibility constraints, EPA is requiring emissions reductions be implemented in two phases. The first phase of NO_X reductions starts in 2009 (covering 2009–2014) and the first phase of SO_2 reductions starts in 2010 (covering 2010–2014); the second phase of reductions for both NO_X and SO_2 starts in 2015 (covering 2015 and thereafter). For States subject to findings of significant contribution for $PM_{2.5}$, EPA is establishing annual emissions budgets. For States subject to findings of significant contribution for 8-hour ozone, the CAIR specifies ozone-season NO_X emissions budgets. States subject to findings for both $PM_{2.5}$ and ozone will have both an annual and an ozone season NO_X budget.

The EPA is providing, as an option to States, model cap and trade programs for EGUs. The EPA will administer these programs, which will be governed by rules provided by EPA that States may adopt or incorporate by reference.

With respect to federally recognized Indian Tribes, the applicability of this rule is governed by three factors: The flexible regulatory framework for Tribes provided by the CAA and the Tribal Authority Rule (TAR); the absence of any existing EGUs on Tribal lands in the CAIR region; and the existence of reservations within the geographic areas which we determined to contribute significantly to nonattainment areas.

Under CAA section 301(d) as implemented by the TAR, eligible Indian Tribes may implement all, but are not required to implement any, programs under the CAA for which EPA has determined that it is appropriate to treat Tribes similarly to States. Tribes may also implement ''reasonably severable'' elements of programs (40 CFR 49.7(c)). In the absence of Tribal implementation of a CAA program or programs, EPA will utilize Federal implementation for the relevant area of Indian country as necessary or appropriate to protect air quality, in consultation with the Tribal government.

The TAR contains a list of provisions for which it is not appropriate to treat Tribes in the same manner as States (40 CFR 49.4). The CAIR is based on the States' obligations under CAA section 110(a)(2)(D) to prohibit emissions which would contribute significantly to nonattainment in, or interfere with maintenance by, other States due to pollution transport. Because CAA section 110(a)(2)(D) is not among the provisions we determined to be inappropriate to apply to Tribes in the same manner as States, that section is applicable, where necessary and appropriate, to Tribes.

However, among the CAA provisions not appropriate for Tribes are ''[s]pecific plan submittal and implementation deadlines for NAAQS-related requirements * * *'' (40 CFR 49.4(a)). Therefore, Tribes are not required to submit implementation plans under section 110(a)(2)(D). Moreover, because no Tribal lands in the CAIR region currently contain any of the sources (EGUs) on which we based the emissions reductions requirements applicable to States, there are no emission reduction requirements applicable to Tribes.

At the same time, the existence of the CAIR cap and trade program in some or all of the affected States will have implications for any future construction of EGUs on Tribal lands. The geographic scope of the CAIR cap and trade program is being determined by a two step-process: the EPA's determination of which States significantly contribute to downwind areas, and the decision by those affected States whether to satisfy their emission reduction requirement by participating in the CAIR cap and trade program.

With respect to the first step of this process (significant contribution test), notwithstanding the political autonomy of Tribes, we view the zero-out modeling as representing the entire geographic area within the State being considered, regardless of the jurisdictional status of areas within the State. Therefore, any EGU constructed in the future on a reservation within a CAIR-affected State would be located in an area which we have already determined to significantly contribute to downwind nonattainment.[9]

With respect to decisions by States to participate in the CAIR cap and trade program, because Tribal governments are autonomous, such a decision would not be directly binding for any Tribe located within the State.

Nonetheless, as a matter of a policy, cap and trade programs by their nature must apply consistently throughout the geographic region of the program in order to be effective. Otherwise, the existence of areas not covered by the cap could create incentives to locate sources there, and thereby undermine

[8] In today's final rule, when we use the term ''transport'' we mean to include the transport of both fine particles ($PM_{2.5}$) and their precursor emissions and/or transport of both ozone and its precursor emissions.

[9] In this regard, the construction of a new EGU on a reservation would be analogous to the construction of a new EGU within a county or region of a CAIR-affected State that does not presently contain any EGUs. This is not meant to imply that Tribes are in any way legally similar to counties, only that, within the CAIR region, the geographic scale of reservations is more similar to counties than to States.

the environmental goals of the program.[10]

In light of these considerations, in the event of any future planned construction of EGUs on Tribal lands within the CAIR region, EPA intends to work with the relevant Tribal government to regulate the EGU through either a Tribal implementation plan (TIP) or a Federal implementation plan (FIP). We anticipate that at a minimum, a proposed EGU on a reservation within a State participating in the CAIR cap and trade program would need to be made subject to the cap and trade program. In the case of a new EGU on a reservation in a CAIR-affected State which chose not to participate in the cap and trade program, the new EGU might also be required, through a TIP or FIP, to participate in the program. This would depend on the potential for emissions shifting and other specific circumstances (*e.g.*, whether the EGU would service the electric grid of States involved in the cap and trade program.) Again, EPA will work with the relevant Tribal government to determine the appropriate application of the CAIR.

Finally, as discussed in the SNPR, Tribes have objected to emissions trading programs that allocate allowances based on historic emissions, on the grounds that this rewards first-in-time emitters at the expense of those who have not yet enjoyed a fair opportunity to pursue economic development. Comments on the CAIR proposal from Tribes requested a Federal set-aside of allowances for Tribes, or other special Tribal allowance provisions. The few comments received from States on the issue generally opposed allocations based on Indian country status. One State expressed a willingness to share its emissions budget with Tribes in the event an EGU locates in Indian country.

The EPA does not believe there is sufficient information to design Tribal allocation provisions at this time. A program designed to address concerns which remain largely speculative is likely to create more problems through unintended consequences than it solves. Therefore, rather than create a Federal allowance set-aside for Tribes, EPA will work with Tribes and potentially affected States to address concerns regarding the equity of allowance allocations on a case-by-case basis as the need arises. The EPA may choose to revisit this issue through a separate rulemaking in the future.

B. Why Is EPA Taking This Action?

Emissions reductions to eliminate transported pollution are required by the CAA, as noted above. There are strong policy reasons for addressing interstate pollution transport.

1. Policy Rationale for Addressing Transported Pollution Contributing to $PM_{2.5}$ and Ozone Problems

Emissions from upwind States can alone, or in combination with local emissions, result in air quality levels that exceed the NAAQS and jeopardize the health of residents in downwind communities. Control of $PM_{2.5}$ and ozone requires a reasonable balance between local and regional controls. If significant contributions of pollution from upwind States that can be abated by highly cost-effective controls are unabated, the downwind area must achieve greater local emissions reductions, thereby incurring extra clean-up costs. Requiring reasonable controls for both upwind and local emissions sources should result in achieving air quality standards at a lesser cost than a strategy that relies solely on local controls. For all these reasons, addressing interstate transport in advance of the time that States must adopt local nonattainment plans, will make it easier for States to develop their nonattainment plans because the States will know the degree to which the pollution flowing into their nonattainment areas will be reduced.

The EPA addressed interstate pollution transport for ozone in the NO_X SIP Call rule published in 1998.[11] Today's rulemaking is EPA's first attempt to address interstate pollution transport for $PM_{2.5}$. The NO_X SIP Call is substantially reducing ozone transport, helping downwind areas meet the 1-hour and 8-hour ozone standards. The EPA has reassessed ozone transport in this rulemaking for two reasons. First, several years have passed since promulgation of the NO_X SIP Call and updated air quality and emissions data are available. Second, some areas are expected to face substantial difficulty in meeting the 8-hour ozone standards. As a result, EPA has determined it is important to assess the degree to which ozone transport will remain a problem after full implementation of the NO_X SIP Call, and to assess whether further controls are warranted to ensure continued progress toward attainment. The modeling for the CAIR includes the NO_X SIP Call in the baseline and examines later years than the NO_X SIP Call analyses.

a. The $PM_{2.5}$ Problem

By action dated July 18, 1997, we revised the NAAQS for particulate matter (PM) to add new standards for fine particles, using as the indicator particles with aerodynamic diameters smaller than a nominal 2.5 micrometers, termed $PM_{2.5}$ (62 FR 38652). We established health- and welfare-based (primary and secondary) annual and 24-hour standards for $PM_{2.5}$. The annual standards are 15 micrograms per cubic meter, based on the 3-year average of annual mean $PM_{2.5}$ concentrations. The 24-hour standard is a level of 65 micrograms per cubic meter, based on the 3-year average of the annual 98th percentile of 24-hour concentrations. The annual standard is generally considered the most limiting.

Fine particles are associated with a number of serious health effects including premature mortality, aggravation of respiratory and cardiovascular disease (as indicated by increased hospital admissions, emergency room visits, absences from school or work, and restricted activity days), lung disease, decreased lung function, asthma attacks, and certain cardiovascular problems such as heart attacks and cardiac arrhythmia. The EPA has estimated that attainment of the $PM_{2.5}$ standards would prolong tens of thousands of lives and would prevent, each year, tens of thousands of hospital admissions as well as hundreds of thousands of doctor visits, absences from work and school, and respiratory illnesses in children.

Individuals particularly sensitive to fine particle exposure include older adults, people with heart and lung disease, and children. More detailed information on health effects of fine particles can be found on EPA's Web site at: *http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_index.html.*

At the time EPA established the $PM_{2.5}$ primary NAAQS in 1997, we also established welfare-based (secondary) NAAQS identical to the primary standards. The secondary standards are designed to protect against major environmental effects caused by PM such as visibility impairment—including in Class I areas which include national parks and wilderness areas across the country—soiling, and materials damage.

[10] Although it is possible that the CAIR cap and trade program may cover a discontinuous area depending on which States participate, the failure of a State to participate does not raise the same environmental integrity concern. A state that does not participate in the cap and trade program must still submit a SIP that limits emissions to the levels mandated by the CAIR emission reduction requirements, taking into account any emissions from new sources.

[11] "Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule," (63 FR 57356; October 27, 1998).

As discussed in other sections of this preamble, SO_2 and NO_X emissions both contribute to fine particle concentrations. In addition, NO_X emissions contribute to ozone problems, described in the next section. We believe the CAIR will significantly reduce SO_2 and NO_X emissions that contribute to the $PM_{2.5}$ and 8-hour ozone problems described here.

The $PM_{2.5}$ ambient air quality monitoring for the 2001–2003 period shows that areas violating the standards are located across much of the eastern half of the United States and in parts of California, and Montana. Based on these nationwide data, 82 counties have at least one monitor that violates either the annual or the 24-hour $PM_{2.5}$ standard. Most areas violate only the annual standard; a small number of areas violate both the annual and 24-hour standards; and no areas violate just the 24-hour standard. The population of these 82 counties totals over 56 million people.

Only two States in the western part of the U.S., California and Montana, have counties that exceeded the $PM_{2.5}$ standards. On the other hand, in the eastern part of the U.S., 124 sites in 69 counties (with total population of 34 million) violated the annual $PM_{2.5}$ standard of 15.0 micrograms per cubic meter ($\mu g/m^3$) over the 3-year period from 2001 to 2003, while 469 sites met the annual standard. No sites in the eastern part of the United States exceeded the daily $PM_{2.5}$ standard of 65 $\mu g/m^3$. The 69 violating counties are located in a region made up of 16 States (plus the District of Columbia), extending eastward from St. Louis County, Missouri, the western-most violating county and including the following States: Alabama, Delaware, Georgia, Illinois, Indiana, Kentucky, Maryland, Missouri, Michigan, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Tennessee, West Virginia, and the District of Columbia. The EPA published the $PM_{2.5}$ attainment and nonattainment designations on January 5, 2005 (70 FR 944). The designations will be effective on April 5, 2005.

Because interstate transport is not believed to be a significant contributor to exceedances of the $PM_{2.5}$ standards in California or Montana, today's final CAIR does not cover these States.

b. The 8-Hour Ozone Problem

By action dated July 18, 1997, we promulgated identical revised primary and secondary ozone standards that specified an 8-hour ozone standard of 0.08 parts per million (ppm). Specifically, under the standards, the 3-year average of the fourth highest daily maximum 8-hour average ozone concentration may not exceed 0.08 ppm. In general, the revised 8-hour standards are more protective of public health and the environment and more stringent than the pre-existing 1-hour ozone standards. All areas that were violating the 1-hour ozone standard at the time of the 8-hour ozone designations were also designated as nonattainment for the 8-hour ozone standard. More areas do not meet the 8-hour standard than do not meet the 1-hour standard. The EPA published the 8-hour ozone attainment and nonattainment designations in the **Federal Register** on April 30, 2004 (69 FR 23858). The designations were effective on June 15, 2004. Pursuant to EPA's final rule to implement the 8-hour ozone standard (69 FR 23951; April 30, 2004), EPA will revoke the 1-hour ozone standard on June 15, 2005, 1 year after the effective date of the 8-hour designations.

Short-term (1- to 3-hour) and prolonged (6- to 8-hour) exposures to ambient ozone have been linked to a number of adverse health effects. Short-term exposure to ozone can irritate the respiratory system, causing coughing, throat irritation, and chest pain. Ozone can reduce lung function and make it more difficult to breathe deeply. Breathing may become more rapid and shallow than normal, thereby limiting a person's normal activity. Ozone also can aggravate asthma, leading to more asthma attacks that require a doctor's attention and the use of additional medication. Increased hospital admissions and emergency room visits for respiratory problems have been associated with ambient ozone exposures. Longer-term ozone exposure can inflame and damage the lining of the lungs, which may lead to permanent changes in lung tissue and irreversible reductions in lung function. A lower quality of life may result if the inflammation occurs repeatedly over a long time period (such as months, years, a lifetime).

People who are particularly susceptible to the effects of ozone include children and adults who are active outdoors, people with respiratory diseases, such as asthma, and people with unusual sensitivity to ozone.

In addition to causing adverse health effects, ozone affects vegetation and ecosystems, leading to reductions in agricultural crop and commercial forest yields; reduced growth and survivability of tree seedlings; and increased plant susceptibility to disease, pests, and other environmental stresses (*e.g.*, harsh weather). In long-lived species, these effects may become evident only after several years or even decades and have the potential for long-term adverse impacts on forest ecosystems. Ozone damage to the foliage of trees and other plants can also decrease the aesthetic value of ornamental species used in residential landscaping, as well as the natural beauty of our national parks and recreation areas. The economic value of some welfare losses due to ozone can be calculated, such as crop yield loss from both reduced seed production (*e.g.*, soybean) and visible injury to some leaf crops (*e.g.*, lettuce, spinach, tobacco), as well as visible injury to ornamental plants (*i.e.*, grass, flowers, shrubs). Other types of welfare loss may not be quantifiable (*e.g.*, reduced aesthetic value of trees growing in heavily visited national parks). More detailed information on health effects of ozone can be found at the following EPA Web site: *http://www.epa.gov/ttn/naaqs/standards/ozone/s_o3_index.html*.

Almost all areas of the country have experienced some progress in lowering ozone concentrations over the last 20 years. As reported in the EPA's report, "The Ozone Report: Measuring Progress Through 2003," [12] national average levels of 1-hour ozone improved by 29 percent between 1980 and 2003 while 8-hour levels improved by 21 percent over the same time period. The Northeast and West regions have shown the greatest improvement since 1980. However, most of that improvement occurred during the first part of the period. In fact, during the most recent 10 years, ozone levels have been relatively constant reflecting little if any air quality improvement. For this reason, ozone has exhibited the slowest progress of the six major pollutants tracked nationally.

Although ambient ozone levels remained relatively constant over the past decade, additional control requirements have reduced emissions of the two major ozone precursors, VOC and NO_X, although at different rates. Emissions of VOCs were reduced by 32 percent from 1990 levels, while emissions of NO_X declined by 22 percent.

Ozone remains a significant public health concern. Presently, wide geographic areas, including most of the nation's major population centers, experience unhealthy ozone levels, that is, concentrations violating the NAAQS for 8-hour ozone. These areas include much of the eastern part of the United States and large areas of California. More specifically, 297 counties with a total population of over 124 million people currently violate the 8-hour ozone standard. Most of these ozone

[12] EPA 454/K–04–001, April 2004.

violations occur in the eastern half of the United States: 268 counties with a population of over 93 million.

When ozone and $PM_{2.5}$ are examined jointly, 322 counties with 131 million people are violating at least one of the standards while 57 counties nationwide have concentrations violating both standards with a total population of over 49 million people. Of these, 46 counties with a population of over 28 million are in the Eastern United States.

c. Other Environmental Effects Associated With SO_2 and NO_X Emissions

Today's action will result in benefits in addition to the enumerated human health and welfare benefits resulting from reductions in ambient levels of $PM_{2.5}$ and ozone. Reductions in NO_X and SO_2 will contribute to substantial visibility improvements in many parts of the Eastern U.S. where people live, work, and recreate, including Federal Class I areas such as the Great Smoky Mountains. Reductions in these pollutants will also reduce acidification and eutrophication of water bodies in the region. In addition, reduced mercury emissions are anticipated as a result of this rule. Reduced mercury emissions will lessen mercury contamination in lakes and thereby potentially decrease both human and wildlife exposure to mercury-contaminated fish.

2. The CAA Requires States To Act as Good Neighbors by Limiting Downwind Impacts

The CAA includes the ''good neighbor'' provision of section 110(a)(2)(D), which requires that every SIP prohibit emissions from any source or other type of emissions activity in amounts that will contribute significantly to nonattainment in any downwind State, or that will interfere with maintenance in any downwind State. In today's action, EPA is determining that 28 States and the District of Columbia, all in the eastern part of the United States, have emissions of SO_2 and/or NO_X that will contribute significantly to nonattainment, or interfere with maintenance, of the $PM_{2.5}$ NAAQS and/or the 8-hour ozone NAAQS in another State. Under EPA's general authority to clarify the applicability of CAA requirements, as provided in CAA section 301(a)(1), EPA is establishing the amount of SO_2 and NO_X emissions that each affected State must prohibit by submitting appropriate SIP provisions to EPA. The improvements in air quality will assist downwind States in developing their SIPs to provide for attainment and maintenance in those nonattainment areas.

3. Today's Rule Will Improve Air Quality

The EPA has estimated the improvements in emissions and air quality that would result from implementing the CAIR. These improvements, which are substantial, are summarized earlier in this section.

C. What Was the Process for Developing This Rule?

By action dated January 30, 2004, EPA issued a proposal that included many of the components of today's action. ''Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Interstate Air Quality Rule); Proposed Rule,'' (69 FR 4566). The Administrator signed the proposed rule—termed, at that time, the Interstate Air Quality Rule—on December 17, 2003, and EPA posted it on its Web site for this rule on that date. The Web site address at that time was *http://www.epa.gov/interstateairquality.* (The address has since changed to *http://www.epa.gov/cleanairinterstaterule/* or *http://www.epa.gov/cair/.*)

The EPA held public hearings on the proposal, in conjunction with a proposed rulemaking concerning mercury and other hazardous air pollutants from EGUs, on February 25–26, 2004, in Chicago, Illinois; Philadelphia, Pennsylvania; and Research Triangle Park, North Carolina. The comment period for the NPR closed on March 30, 2004. The EPA received over 6,700 comments on the proposal.

By action dated June 10, 2004, EPA issued a supplemental notice of proposed rulemaking (SNPR), ''Supplemental Proposal for the Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule); Proposed Rule,'' (69 FR 32684). The Administrator signed the SNPR for this rule—now called the Clean Air Interstate Rule—on May 18, 2004, and EPA placed it on the Web site on that date. The SNPR included, among other things, proposed regulatory language for the rule, revised proposals concerning State-level emissions budgets, proposed State reporting requirements and SIP approvability criteria, and proposed model cap and trade rules. The SNPR also proposed that under certain circumstances the CAIR requirements could replace the BART requirements of CAA sections 169A and 169B. The EPA held a public hearing on the SNPR on June 3, 2004, in Alexandria, Virginia. The comment period for the SNPR closed on July 26, 2004. The EPA received over 400 comments on the SNPR.

By a notice of data availability (NODA) dated August 6, 2004, EPA announced the availability of additional documents for this action. ''Availability of Additional Information Supporting the Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule),'' (69 FR 47828). The documents had been placed on the website on or about July 27, 2004, and in the EDOCKET on that date, or shortly thereafter. The EPA allowed public comment on those additional documents until August 27, 2004. Around 30 comments were received on the NODA.

The EPA has responded to all significant public comments either in this preamble or in the response to comment document which is contained in the docket.

Comments on Rulemaking Process: Some commenters expressed concerns about certain aspects of this process. One concern was that EPA did not allow sufficient time to comment on the SNPR. Commenters noted that important program elements—including regulatory language—appeared for the first time in the SNPR, but EPA held a public hearing on the SNPR 7 days before the SNPR was published in the **Federal Register** and only 16 days after the SNPR had been posted on the website. The EPA believes that the 16-day period preceding the public hearing, and the total of 45 days to comment on the SNPR following its publication in the **Federal Register**, constituted an adequate opportunity for members of the public to comment on the SNPR.

Commenters also expressed concern that certain technical documents were not made available in sufficient time to comment. However, EPA had placed all technical support documents for the NPR in the EDOCKET as of the date of publication of the NPR, and all technical support documents for the SNPR had been placed in the EDOCKET as of the date of publication of the SNPR.

Commenters also expressed concern that in the SNPR, EPA proposed significant changes to other regulatory programs. The EPA agrees that the SNPR did include proposed changes to certain regulatory programs, *i.e.*, the requirements for BART under CAA sections 169A and 169B (concerning visibility), certain provisions (primarily concerning the allowance-holding requirement) in the title IV (Acid Rain Program) rules, and certain emissions reporting rules under the NO_X SIP Call (40 CFR 51.122) and Consolidated

Emissions Reporting Rule (CERR) (title 40, part 51, subpart A). The EPA believes that to the extent the requirements for BART and emissions reporting rule revisions are tied to the CAIR, affected members of the public had adequate notice of those revisions. (These revisions are described in section VII.) However, the SNPR contained some revisions to the emissions reporting rules that were not tied to the transport provisions. The EPA is not taking final action today on the proposal for the emissions reporting rules that were not tied to the transport provisions and instead is issuing a new proposal for them, which will provide additional notice and opportunity to comment.

Further, the Acid Rain Program rule revisions, although connected to the CAIR, apply to all persons subject to the Acid Rain Program, including persons who are not affected by the CAIR. (These revisions are described in section IX.) Specifically, as explained in section IX, the revisions to the Acid Rain Program rules are aimed at facilitating coordination of the Acid Rain Program and the CAIR model SO_2 cap and trade rule and/or are being adopted on their own merits, independently of the need to coordinate with the CAIR. Most of the proposed revisions involve changing from unit-by-unit to source-by-source compliance with the allowance-holding requirement of the Acid Rain Program and therefore affect every source subject to the Acid Rain Program, whether or not the source is also in a State covered by the CAIR. The change to source-by-source compliance increases a source's flexibility to use—in meeting the allowance-holding requirement—allowances held by any unit at the source. This flexibility reduces the likelihood that sources will incur large excess emissions penalties from inadvertent, minor errors (*e.g.*, in how allowances are distributed among the units at the source), while preserving the environmental goals of the Acid Rain Program. The remaining revisions to the Acid Rain Program rules similarly cover all Acid Rain Program sources. Indeed, none of the comments on the proposed Acid Rain Program rule revisions stated that the revisions would apply only to certain Acid Rain Program sources, but rather seemed to treat the revisions as applying program-wide. As discussed in section IX, EPA is finalizing, with minor modifications, the Acid Rain Program rule revisions.

Commenters also expressed concern that between the NPR and the SNPR, EPA had proposed program elements in a piecemeal fashion, which made it more difficult to comprehend and comment on the rule, and that the SNPR's comment period was too short to allow the public adequate opportunity to comment on the numerous and complex issues raised in that proposal. The EPA recognizes the challenges faced by commenters in this rulemaking, however, we believe that the comment periods for the NPR and SNPR were adequate, and note that we did receive extensive and highly detailed, technical comments on both proposals.

D. What Are the Major Changes Between the Proposals and the Final Rule?

The EPA is finalizing a number of revisions to the proposed elements of the CAIR. These revisions are in response to information received in public comments and new analyses conducted by EPA. The following is a summary list of those changes:

- The first phase of NO_X reductions starts in 2009 (covering 2009–2014) instead of 2010. The first phase of the SO_2 reductions still starts in 2010 (covering 2010–2014).
- The emissions inventories used for $PM_{2.5}$ and 8-hour ozone air quality modeling have been updated and improved; we modeled $PM_{2.5}$ using the Community Multiscale Air Quality Model (CMAQ) and meteorology for 2001 instead of the Regional Model for Simulating Aerosols and Deposition (REMSAD) and meteorology for 1996.
- The final CAIR does not cover Kansas based on new analyses of its contribution to downwind $PM_{2.5}$ nonattainment.
- Arkansas, Delaware, Massachusetts, and New Jersey are not subject to the CAIR based on their contribution to $PM_{2.5}$ nonattainment and maintenance. However, they remain subject to NO_X emissions reductions requirements on the basis of their contribution to downwind 8-hour ozone nonattainment. This requirement is for the ozone season rather than the entire year. The EPA is issuing a new proposal to include Delaware and New Jersey for the $PM_{2.5}$ NAAQS based on additional considerations.
- The change in States covered by the rule necessitates a re-analysis of the NO_X budgets for all covered States. This changes the amount of the budget, but not the procedure EPA used to calculate it.
- The SIP approval criteria have been changed to no longer exclude measures otherwise required by the CAA from being included in the State's compliance with CAIR.
- A 200,000 ton compliance supplement pool was added for NO_X. Allowances from this pool can either be awarded to sources that make early reductions or to sources that demonstrate need.
- All States for which EPA has made a finding with respect to ozone are subject to an ozone season cap. In order to implement this ozone season cap, EPA has finalized an ozone season NO_X trading program in addition to the annual NO_X and SO_2 trading programs that were proposed.
- A number of changes were made to the trading rule including: changes to the model NO_X allocation methodology (to fuel weight allocations) and the addition of opt in provisions.
- The EPA is not finalizing some of the emissions reporting requirements in response to public comments indicating we gave inadequate notice of the changes that were proposed to be applicable to all States, not just those affected by the CAIR emission reduction requirements. These are being reproposed, with modifications, in a separate action to allow additional opportunity for public comment by all affected States and other parties.

II. The EPA's Analytical Approach

Overview: Today's rulemaking is based on the ''good neighbor'' provision of CAA section 110(a)(2)(D), which requires States to develop SIP provisions assuring that emissions from their sources do not contribute significantly to downwind nonattainment, or interfere with maintenance, of the NAAQS. The EPA interpreted this provision, and developed a detailed methodology for applying it, in the NO_X SIP Call rulemaking, which concerned interstate transport of ozone precursors.

Today's rule requires upwind States to submit SIP revisions requiring their sources to reduce emissions of certain precursors that significantly contribute to nonattainment in, or interfere with maintenance of, the $PM_{2.5}$ and 8-hour ozone national ambient air quality standards in downwind States. The EPA developed today's rule relying heavily on the NO_X SIP Call approach.

This section of the preamble outlines the key aspects of today's approach, some of which are described in greater detail in other sections of the preamble. The EPA received comments on today's approach that we respond to either in this section or in the other sections of the preamble. This section also describes how today's approach varies from the NO_X SIP Call, which variations result from, among other things, the fact that today's action regulates a different pollutant ($PM_{2.5}$) with a different precursor (SO_2).

A. How Did EPA Interpret the Clean Air Act's Pollution Transport Provisions in the NO_X SIP Call?

1. Clean Air Act Requirements

The central CAA provisions concerning pollutant transport, for purposes of today's action, are found in section 110(a)(2)(D). Under these provisions, each SIP must—

(D) Contain adequate provisions

(i) Prohibiting * * * any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—

(I) Contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any * * * national primary or secondary ambient air quality standard * * *.

2. The NO_X SIP Call Rulemaking

Promulgated by action dated October 27, 1998, the NO_X SIP Call was EPA's principal effort to reduce interstate transport of precursors for both the 1-hour ozone NAAQS and the 8-hour ozone NAAQS. (See ''Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone; Rule,'' (63 FR 57356).) In that rulemaking, EPA imposed seasonal NO_X reduction requirements on 22 States and the District of Columbia in the eastern part of the country.

a. Analytical Approach of NO_X SIP Call

In the NO_X SIP Call, EPA interpreted section 110(a)(2)(D) to authorize EPA to determine the amount of emissions in upwind States that ''contribute significantly'' to downwind nonattainment or ''interfere with'' downwind maintenance, and to require those States to eliminate that amount of emissions. The EPA recognized that States must retain full authority to choose the sources to control, and the control mechanisms, to achieve those reductions.

The EPA set out several criteria or factors for the ''contribute significantly'' test, and further indicated that the same criteria should apply to the ''interfere with maintenance'' provision: [13]

* * * EPA determined the amount of emissions that significantly contribute to downwind nonattainment from sources in a particular upwind State primarily by (i) evaluating, with respect to each upwind State, several air quality related factors, including determining that all emissions from the State have a sufficiently great impact downwind (in the context of the collective contribution nature of the ozone problem); and (ii) determining the amount of that State's emissions that can be eliminated through the application of cost-effective controls. Before reaching a conclusion, EPA evaluated several secondary, and more general, considerations. These include:

- The consistency of the regional reductions with the attainment needs of the downwind areas with nonattainment problems.
- The overall fairness of the control regimes required of the downwind and upwind areas, including the extent of the controls required or implemented by the downwind and upwind areas.
- General cost considerations, including the relative cost-effectiveness of additional downwind controls compared to upwind controls.

63 FR 57403

i. Air Quality Factor

The first factor concerns evaluating the impact on downwind air quality of the upwind State's emissions. As EPA stated in the NO_X SIP Call: * * *

EPA specifically considered three air quality factors with respect to each upwind State * * *.

- The overall nature of the ozone problem (*i.e.*, ''collective contribution'').
- The extent of the downwind nonattainment problems to which the upwind State's emissions are linked, including the ambient impact of controls required under the CAA or otherwise implemented in the downwind areas.
- The ambient impact of the emissions from the upwind State's sources on the downwind nonattainment problems.

63 FR 57376

The EPA explained the first factor, collective contribution, by noting,

[V]irtually every nonattainment problem is caused by numerous sources over a wide geographic area* * *[. This] factor suggest[s] that the solution to the problem is the implementation over a wide area of controls on many sources, each of which may have a small or unmeasureable ambient impact by itself.

63 FR 57377

The second air quality factor—the extent of downwind nonattainment problems—concerns whether downwind areas should be considered to be in nonattainment. This determination took into account the then-current air quality of the area, the predicted future air quality (assuming the implementation of required controls, but not the transport requirements that were the subject of the NO_X SIP Call), and the boundaries of the area in light of designation status (63 FR 57377).

The EPA applied the third air quality factor—the ambient impact of emissions from the upwind sources—by projecting the amount of the upwind State's entire inventory of anthropogenic emissions to the year 2007, and then quantifying, through the appropriate air quality modeling techniques, the impact of those emissions on downwind nonattainment.[14] Specifically, (i) EPA determined the minimum threshold impact that the upwind State's emissions must have on a downwind nonattainment area to be considered potentially to contribute significantly to nonattainment; and then (ii) for States with impacts above that threshold, EPA developed a set of metrics for further evaluating the contribution of the upwind State's emissions on a downwind nonattainment area (63 FR 57378). The EPA considered a State with emissions that had a sufficiently great impact to contribute significantly to the downwind area (depending on application of the cost factor). In general, EPA established the thresholds at a relatively low level, which reflected the collective contribution phenomenon. That is, because the ozone problem is caused by many relatively small contributions, even relatively small contributors must participate in the solution.

ii. Cost Factor

The cost factor is the second major factor that EPA applied to determine the significant contribution to nonattainment: ''EPA * * * determined whether any amounts of the NO_X emissions may be eliminated through controls that, on a cost-per-ton basis, may be considered to be highly cost effective.'' (*See* 63 FR 57377.)

(I) Choice of Highly Cost-Effective Standard

The EPA selected the standard of highly cost effective in order to assure State flexibility in selecting control strategies to meet the emissions reduction requirements of the rulemaking. That is, the rulemaking required the States to achieve specified levels of emissions reductions—the levels achievable if States implemented the control strategies that EPA identified

[13] In the NO_X SIP Call, because the same criteria applied, the discussion of the ''contribute significantly to nonattainment'' test generally also applied to the ''interfere with maintenance'' test. However, in the NO_X SIP Call, EPA stated that the ''interfere with maintenance'' test applied with respect to only the 8-hour ozone NAAQS (63 FR 57379–80).

[14] Although EPA's air quality modeling techniques examined all of the upwind State's emissions of ozone precursors (including VOC and NO_X), only the NO_X emissions had meaningful interstate impacts.

as highly cost effective—but the rulemaking did not mandate those highly cost-effective control strategies, or any other control strategy. Indeed, in calculating the amount of the required emissions reductions by assuming the implementation of highly cost-effective control strategies, EPA assured that other control strategies—ones that were cost effective, if not highly cost effective—remained available to the States.

(II) Determination of Highly Cost-Effective Amount

The EPA determined the dollar amount considered to be highly cost effective by reference to the cost effectiveness of recently promulgated or proposed NO_X controls. The EPA determined that the average cost effectiveness of controls in the reference list ranged up to approximately $1,800 per ton of NO_X removed (1990$), on an annual basis. The EPA considered the controls in the reference list to be cost effective.

The EPA established $2,000 (1990$) in average cost effectiveness for summer ozone season emissions reductions as, at least directionally, the highly cost-effective amount. Identifying this amount on an ozone season basis was appropriate because the NO_X SIP Call concerned the ozone standard, for which emissions reductions during only the summer ozone season are necessary. This level of costs reflected the fact that in general, States with downwind ozone nonattainment areas had already implemented extensive controls. Accordingly, it was evident that the level of upwind controls EPA selected would prove necessary for the downwind areas to reach attainment.

(III) Source Categories

The EPA then determined that the source categories for which highly cost-effective controls were available included EGUs, large industrial boilers and turbines, and cement kilns. At the same time, EPA determined, for those source categories, the level of controls that would cost an amount consistent with the highly cost-effective amount and that would be feasible. The EPA considered other source categories, but found that highly cost-effective controls were not available from them for various reasons, including the size of the sources, the relatively small amount of emissions from the sources, or the control costs.

iii. Other Factors

The EPA also relied on several other, secondary considerations before concluding that the identified amount of emissions reductions were required. The first concerned the consistency of regional reductions with downwind attainment needs. The EPA ascertained the ozone air quality impacts of the required emissions reductions, and determined that those impacts improved air quality downwind, but not to the point that would raise questions about whether the amount of reductions was more than necessary (63 FR 57379).

The second general consideration was ''the overall fairness of the control regimes'' to which the downwind and upwind areas were subject. The EPA explained:

> Most broadly, EPA believes that overall notions of fairness suggest that upwind sources which contribute significant amounts to the nonattainment problem should implement cost-effective reductions. When upwind emitters exacerbate their downwind neighbors' ozone nonattainment problems, and thereby visit upon their downwind neighbors additional health risks and potential clean-up costs, EPA considers it fair to require the upwind neighbors to reduce at least the portion of their emissions for which highly cost-effective controls are available.
>
> In addition, EPA recognizes that in many instances, areas designated as nonattainment under the 1-hour NAAQS have incurred ozone control costs since the early 1970s. Moreover, virtually all components of their NO_X and VOC inventories are subject to SIP-required or Federal controls designed to reduce ozone. Furthermore, these areas have complied with almost all of the specific control requirements under the CAA, and generally are moving towards compliance with their remaining obligations. The CAA's sanctions and FIP provisions provide assurance that these remaining controls will be implemented. By comparison, many upwind States in the midwest and south have had fewer nonattainment problems and have incurred fewer control obligations.

(63 FR 57379.)

The third general consideration was ''general cost considerations.'' The EPA noted that ''in general, areas that currently have, or that in the past have had, nonattainment problems * * * have already incurred ozone control costs.'' The next set of controls available to these nonattainment areas would be more expensive than the controls available to the upwind areas. The EPA found that this cost scenario further confirmed the reasonableness of the upwind control obligations (63 FR 57379).

In the NO_X SIP Call, EPA considered all of these factors together in determining the level of controls considered to be highly cost effective. This level of controls reflected the then-present state of ozone controls: Within the region, the nonattainment areas were already required to—and had already implemented—VOC and NO_X controls that covered much of their inventory. However, the upwind States in the region generally had not done so (except to the extent of their ozone nonattainment areas). In this context, EPA considered it reasonable to impose an additional control burden on the upwind States. Air quality modeling showed that even with this additional level of upwind controls, residual nonattainment remained, so that further reductions from downwind and/or upwind areas would be necessary.

b. Regulatory Requirements

After ascertaining the controls that qualified as highly cost effective, EPA developed a methodology for calculating the amount of NO_X emissions that each State was required to reduce on grounds that those emissions contribute significantly to nonattainment downwind. The total amount of required NO_X emissions reductions was the sum of the amounts that would be reduced by application of highly cost-effective controls to each of the source categories for which EPA determined that such controls were available (63 FR 57378).

The largest of these source categories was EGUs. The EPA determined the amount of reductions associated with EGU controls by applying the control rate that EPA considered to reflect highly cost-effective controls to each State's EGU heat input. That heat input, in turn, was adjusted to reflect projected growth.

Each affected State retained the authority to achieve the required level of reductions by implementing whatever controls on whatever sources it wished, and EPA determined that there were other source categories for which cost-effective, if not highly cost-effective, controls were available (63 FR 57378). If the States chose to control EGUs, then the NO_X SIP Call mandated certain requirements—including a statewide cap on EGU NO_X emissions—but also made available an EPA-administered regionwide EGU allowance trading program that the States could choose to adopt.

c. SIP Submittal and Implementation Requirements

At the time EPA promulgated the NO_X SIP Call, States already had SIPs for the 1-hour ozone NAAQS in place. In the NO_X SIP Call, EPA determined that the 1-hour SIPs for the affected States were deficient, and EPA called on these States, under CAA section 110(k)(5), to submit, within 12 months of promulgation of the NO_X SIP Call, SIP revisions to cure the deficiency by complying with the NO_X SIP Call regulatory requirements. The EPA further required that the NO_X SIP Call-required controls be implemented as expeditiously as practicable. The EPA determined this date to be within 3 years of the SIP submittal date (with that period extended to the beginning of the next ozone season), in light of the various constraints that EGUs would confront in implementing controls.

For the SIPs due under the 8-hour ozone NAAQS, in the NO_X SIP Call, EPA did not incorporate a section 110(k)(5) SIP call, but instead required States to submit, under section 110(a)(1)–(2), SIP revisions to fulfill the requirements of section 110(a)(2)(D). The EPA required these 8-hour ozone SIPs to be submitted—and the controls mandated therein to be implemented—on the same schedule as the 1-hour SIPs.

However, EPA stayed the 8-hour ozone requirements of the NO_X SIP Call, due to litigation concerning the 8-hour ozone NAAQS. To date, EPA has not lifted that stay.

3. *Michigan* v. *EPA* Court Case

Petitioners brought legal challenges to various components of the NO_X SIP Call's analytical approach in the United States Court of Appeals for the District of Columbia Circuit, in *Michigan* v. *EPA,* 213 F.3d 663 (DC Cir., 2000), *cert. denied,* 532 U.S. 904 (2001). The Court upheld the essential features of the air quality modeling part of EPA's approach, *id.* at 673; as well as EPA's definition of ''contribute significantly'' to include the factor of highly cost-effective controls, *id.* at 679. The Court did vacate or remand certain specific applications of EPA's approach, and delayed the implementation date to May 31, 2004. *See, e.g., id.* at 67, 681–85, 692–94. In addition, in a subsequent case that reviewed separate EPA rulemakings making technical corrections to the NO_X SIP Call, the DC Circuit remanded for a better explanation EPA's methodology for computing the growth component in the EGU heat input calculation. *Appalachian Power Co.* v. *EPA,* 251 F.3d 1026 (DC Cir., 2001).[15]

4. Implementation of the NO_X SIP Call

The court decisions left intact most of the NO_X SIP Call requirements. All States subject to those requirements—which EPA has termed the NO_X SIP Call Phase I requirements—submitted SIPs incorporating them, and requiring control implementation by May 31, 2004 or earlier. The EPA has approved those SIPs.

The EPA responded to the DC Circuit's EGU growth remand decisions through a **Federal Register** action that provided a more detailed explanation and other supporting information for the EGU growth methodology (67 FR 21868; May 1, 2002). The Court subsequently upheld that explanation. *West Virginia* v. *EPA,* 362 F.3d 861 (DC Cir. 2004). In addition, by action dated April 21, 2004, EPA promulgated a rulemaking that responded to other remanded and vacated issues, and included the remaining requirements—termed the NO_X SIP Call Phase II requirements—for the affected States (69 FR 21604).

B. How Does EPA Interpret the Clean Air Act's Pollution Transport Provisions in Today's Rule?

1. CAIR Analytical Approach

Today, EPA adopts much the same interpretation and application of section 110(a)(2)(D) for regulating downwind transport of precursors of $PM_{2.5}$ and 8-hour ozone as EPA adopted for the NO_X SIP Call. We are adjusting some aspects of the NO_X SIP Call analytic approach for various reasons, including the need to account for regulation of a different pollutant ($PM_{2.5}$) with an additional precursor (SO_2).

a. Nature of Nonattainment Problem and Overview of Today's Approach

As described in section I, above, the interstate transport component of current nonattainment of the $PM_{2.5}$ and 8-hour ozone NAAQS is primarily confined to the eastern part of the country, although in an area that is larger, by several States, than the area that EPA focused on in the NO_X SIP Call for only ozone. As described in section III, it is evident that local controls alone cannot be counted on to solve the nonattainment problems, although uncertainties remain in the state of knowledge of these nonattainment problems as well as the precise role interstate and local controls should play. As in the case of the NO_X SIP Call, it is not reasonable to expect a local area to bear the entire burden of solving the air quality problems, even if doing so were technically possible.

Turning to the interstate component of the nonattainment problems, as discussed in section III below, for $PM_{2.5}$, we find sufficient information is available to address the adverse downwind impacts caused by SO_2 and NO_X, and to develop emissions reductions requirements for SO_2 and NO_X. However, we do not have sufficient information to address other precursors. As discussed in section III below, for 8-hour ozone, we reiterate the finding of the NO_X SIP Call that NO_X emissions, and not VOC emissions, are of primary importance for interstate transport purposes.

We interpret CAA section 110(a)(2)(D) to require SIPs in upwind States to eliminate the amounts of emissions that contribute significantly to downwind nonattainment or interfere with downwind maintenance. As described below, in today's rule, EPA determines that upwind States' emissions contribute significantly to nonattainment or interfere with maintenance of the $PM_{2.5}$ NAAQS.

To quantify the amounts of those emissions that contribute significantly to nonattainment, we primarily focus on the air quality factor reflecting the upwind State's ambient impact on downwind nonattainment areas, and the cost factor of highly cost-effective controls. However, as with the NO_X SIP Call, EPA also considers other factors, which serve to establish the broad context for applying the air quality and cost factors. Today, we adopt the formulation of those factors as described in the CAIR NPR, which has little conceptual difference from EPA's application of those factors in the NO_X SIP Call.

Discussion of issues relating to maintenance are found in section III below.

b. Air Quality Factor

i. $PM_{2.5}$

With respect to the $PM_{2.5}$ NAAQS, as described in section VI, we employed air quality modeling techniques to assess the impact of each upwind State's entire inventory of anthropogenic SO_2 and NO_X emissions on downwind nonattainment and maintenance. For air quality and technical reasons described below, EPA determined that upwind SO_2 and NO_X emissions contribute significantly to nonattainment as of the year 2010. Therefore, EPA projected SO_2 and NO_X emissions to the year 2010, assuming certain required controls (but not controls required under CAIR), and then modeled the impact of those projected emissions (termed the base case inventory) on downwind $PM_{2.5}$ nonattainment in that year.

As discussed in section III, we adopt today a threshold air quality impact of 0.2 $\mu g/m^3$, so that an upwind State with contributions to downwind nonattainment below this level would

[15] By action dated January 18, 2000, EPA promulgated another rulemaking that was related to the NO_X SIP Call, known as the section 126 Rule (65 FR 2675). The DC Circuit generally upheld this rule, although it remanded for better explanation the EGU heat input growth methodology. *Appalachian Power Co.* v. *EPA.* 249 F. 3d 1032 (DC Cir., 2001).

not be subject to regulatory requirements, but a State with contributions at or higher than this level would be subject to further evaluation.

Because of the inherent differences between the $PM_{2.5}$ and ozone NAAQS, this threshold necessarily differs from the threshold chosen for the NO_X SIP Call in terms of: (i) The metrics selected to evaluate the threshold, and (ii) the specific level of the threshold. Even so, the threshold EPA proposed for $PM_{2.5}$ is generally consistent with the approach taken in the NO_X SIP Call for the threshold level for ozone in that both are relatively low. This level reflects the fact that $PM_{2.5}$ nonattainment, like ozone, is caused by many sources in a broad region, and therefore may be solved only by controlling sources throughout the region. As with the NO_X SIP Call, the collective contribution condition of $PM_{2.5}$ air quality is reflected in the proposed relatively low threshold.[16]

The EPA determined that as of 2010, 23 upwind States and the District of Columbia will have contributions to downwind $PM_{2.5}$ nonattainment areas that are sufficiently high to meet the air quality factor of the transport test.

ii. 8-Hour Ozone

With respect to the 8-hour ozone NAAQS, we also employed, as described in section VI, air quality modeling techniques to assess the impact of each upwind State's entire inventory of NO_X and VOC emissions on downwind nonattainment. The EPA determined that upwind NO_X emissions contribute significantly to 8-hour ozone nonattainment as of the year 2010. Therefore, EPA projected NO_X emissions to the year 2010, assuming certain required controls (but not controls required under CAIR), and then modeled the impact of those projected emissions (termed the base case inventory) on downwind 8-hour ozone nonattainment in that year.

For the 8-hour ozone air quality factor, EPA employs the same threshold amounts and metrics that it used in the NO_X SIP Call. That is, as described in section VI, emissions from an upwind State contribute significantly to nonattainment if the maximum contribution is at least 2 parts per billion, the average contribution is greater than one percent, and certain other numerical criteria are met.

[16] The second air quality factor described in the NO_X SIP Call—the extent of downwind nonattainment—is reflected in the identification of downwind $PM_{2.5}$ nonattainment areas, discussed elsewhere in today's final action. The third air quality factor—the ambient impact of upwind emissions—is reflected in the threshold level.

The EPA determined that as of 2010, 25 upwind States and the District of Columbia will have contributions to downwind nonattainment areas that are sufficiently high to meet the air quality factor of the transport test.

c. Cost Factor

The second major factor that EPA applies is the cost factor. As in the case of the NO_X SIP Call, EPA interprets this factor as mandating emissions reductions in amounts that would result from application of highly cost-effective controls. We ascertain the level of costs as highly cost effective by reference to the cost effectiveness of recent controls. As we stated in the CAIR NPR, in determining the appropriate level of controls, we considered feasibility issues—as we did in the NO_X SIP Call—specifically, ''the applicability, performance, and reliability of different types of pollution control technologies for different types of sources; * * * and other implementation costs of a regulatory program for any particular group of sources.'' (*See* CAIR NPR, 69 FR 4585.)

As described in section IV, today we conclude that at present, EGUs are the only source category for which highly cost-effective SO_2 and NO_X controls are available. In making this determination, we examined what information is available concerning which source categories emit relatively large amounts of emissions, and what difficulties sources have in implementing controls. These criteria are similar to those considered in the NO_X SIP Call.

As discussed in section IV, for $PM_{2.5}$, today's action finalizes our proposal to identify as highly cost effective the dollar amount of cost effectiveness that falls near the low end of the reference range for both annual SO_2 controls and annual NO_X controls. We identify this level based on the overall context of the $PM_{2.5}$ implementation program, discussed below.

For upwind States affecting downwind 8-hour ozone nonattainment areas, we apply the cost factor for ozone-season NO_X controls in much the same manner as for the NO_X SIP Call, although some aspects of the analysis have been updated. The level of NO_X control identified as highly cost effective is more stringent than in the NO_X SIP Call.

d. Other Factors

As with the NO_X SIP Call, EPA considers other factors that influence the application of the air quality and cost factors, and that confirm the conclusions concerning the amounts of emissions that upwind States must eliminate as contributing significantly to downwind nonattainment. Specifically, as we stated in the CAIR NPR, ''We are striving in this proposal to set up a reasonable balance of regional and local controls to provide a cost effective and equitable governmental approach to attainment with the NAAQS for fine particles and ozone.'' (See 69 FR 4612.) In this manner, we broadly incorporate the fairness concept and relative-cost-of-control (regional costs compared to local costs) concept that we generally considered in the NO_X SIP Call.

i. $PM_{2.5}$ Controls

For $PM_{2.5}$, we promulgated the NAAQS in 1997, we issued designations of areas in December 2004 (70 FR 944; January 5, 2005), and we intend to promulgate implementation requirements during 2005. We project that by 2010, without CAIR or other controls not already adopted, 80 counties in the CAIR region would be in nonattainment of the annual standard.

Our state of knowledge is incomplete as to the best control regime to achieve attainment and maintenance of this NAAQS in individual areas, but we do know that transported SO_2 and NO_X emissions are important contributors to $PM_{2.5}$ nonattainment. In addition, we have concluded that available controls for at least the portion of these emissions from EGUs are feasible and relatively inexpensive on a cost-per-ton basis, and generate significant ambient benefits. These ambient benefits include bringing many areas into attainment and decreasing $PM_{2.5}$ levels in the rest of the nonattainment areas. Moreover, available information indicates that local controls are likely to be relatively more expensive on a per-ton basis, and will not reduce emissions sufficiently to bring many areas into attainment.

In light of this information, we plan to proceed by requiring the level of regulatory control specified today on upwind SO_2 and NO_X emissions. We consider today's action to be both prudent and effective within the circumstances of the developing $PM_{2.5}$ implementation program. This action is one of the initial steps in implementing the $PM_{2.5}$ NAAQS. States, localities, and Tribes, as well as EPA, will continue to evaluate the efficacy of local controls. Finally, as discussed in section VI, air quality modeling confirms that these regional controls are not more than is necessary for downwind areas to attain.

This overall plan is well within the ambit of EPA's authority to proceed with regulation on a step-by-step basis. The time frame for section 110(a)(2)(D) SIPs, described in section VII, makes clear that EPA has the authority to establish the upwind reduction obligations before having full information about how best to achieve attainment goals, including having full information about downwind control costs and the efficacy of downwind control measures.

ii. Ozone Controls

The EPA determined the level of required NO_X reductions for purposes of 8-hour ozone transport through much the same process as for purposes of $PM_{2.5}$ transport.

e. Regulatory Requirements

i. Annual SO_2 and NO_X Emissions Reductions

Although EPA determined that upwind emissions will contribute significantly to both $PM_{2.5}$ nonattainment and 8-hour ozone nonattainment in 2010, the amount of requisite emissions controls cannot feasibly be implemented by 2009 for NO_X, or 2010 for SO_2. Instead, EPA has determined to implement the reductions in two phases for each pollutant: 2009 for NO_X, and 2010 for SO_2 initially, with lower caps for both in 2015.

As described in section IV, EPA evaluated the cost of emissions reductions under consideration against the level of highly cost-effective controls. Through a multi-year process involving studies and other regulatory and legislative efforts, as well as involvement with citizen, industry, and State stakeholders, EPA arrived at an amount of SO_2 emissions reductions for evaluation purposes for the CAIR region. The EPA ascertained the costs of these reductions and today determines that they should be considered highly cost effective. These amounts correspond to reducing Title IV SO_2 allowances for utilities by 65 percent in 2015 and 50 percent in 2010 in CAIR States.

As described in section V, EPA further determined that these emissions reductions requirements should be allocated to the States in proportion to the title IV SO_2 allowances allocated under the CAA to their EGUs. This approach is consistent with the system Congress established for allocating title IV allowances and facilitates implementation of the SO_2 interstate trading program.

For annual NO_X emissions, EPA determined a target regionwide amount of both emissions reductions and the EGU budget by multiplying current heat input by emission rates of 0.125 lb/mmBtu and 0.15 lb/mmBtu for 2015 and 2010, respectively. The EPA then evaluated those amounts through the Integrated Planning Model (IPM), which indicated the associated amounts of heat input and emission rates projected for those years. The IPM indicated that the amounts of heat input for 2015 and 2010 were higher than current heat input (in light of the increased electricity demand for 2015 and 2010), and that the emissions rates were lower than 0.125 lb/mmBtu (2015) and 0.15 lb/mmBtu (2010). The IPM calculated the costs to achieve those emissions reductions and EGU budget (assuming EGU controls) by 2015 and 2009, which costs EPA determined were highly cost effective and feasible, respectively. The EPA used this same approach to determine the seasonal budget for NO_X reductions for purposes of the ozone standard.

As described in section V, we allocated this regionwide amount to the individual States in accordance with their average heat input from EGUs both subject to and not subject to title IV. We adjusted heat input for type of fuel used. The EPA believes that this method is a reasonable indicator of each State's appropriate share of the requirements. This method differs from what EPA used in the NO_X SIP Call, which relied on State-specific projections of growth in heat input.

We require implementation of the $PM_{2.5}$ and 8-hour ozone reductions in two phases, in 2009 and 2015. As discussed in section IV, these dates are the most expeditious that are practicable—the same standard for the implementation period in the NO_X SIP Call—based on engineering and financial factors; the performance and applicability of control measures; and the impact of implementation on, in the case of EGUs, electricity reliability. The EPA considered these same factors in determining the implementation period for the NO_X SIP Call requirements, but factual differences lead to the two-phase approach adopted in today's action.

As discussed in section VII, each upwind State may achieve the required reductions by regulating any sources of SO_2 or NO_X that it wishes. However, if the State chooses to regulate certain source categories (such as EGUs), it must comply with certain requirements (such as capping EGU emissions), and it may take advantage of certain opportunities (such as participation in the EPA-administered EGU cap and trade program). Some aspects of these requirements and the cap and trade program differ from those in the NO_X SIP Call, as explained in section VIII. However, like the NO_X SIP Call, the State may allow sources to opt in to the CAIR trading program, as described in section VIII.

f. SIP Submittal and Implementation Requirements

Today EPA requires that the $PM_{2.5}$ and 8-hour ozone SIPs be submitted within 18 months of promulgation of today's action. This period is 6 months longer than the SIPs due under the NO_X SIP Call. This difference is due to the fact that $PM_{2.5}$ implementation is only now beginning, and it makes sense to keep the NO_X SIPs due under the 8-hour ozone requirements on the same schedule as the NO_X and SO_2 SIPs due under the $PM_{2.5}$ requirements.

2. What Did Commenters Say and What Is EPA's Response?

Many of the comments on today's action concern various aspects of EPA's analytical approach. Most of those comments are discussed elsewhere in today's action. Comments on the most basic elements of EPA's approach are discussed here.

a. Aspects of Contribute-Significantly Test

i. Date for Evaluation of Downwind Impacts

Comment: Some commenters took issue with EPA's approach of determining the upwind State's air quality impact on downwind areas by modeling only the State's 2010 base case emissions (that is, projected 2010 emissions before the 2010 CAIR controls). These commenters stated that although evaluating the upwind State's base case emissions in 2010 might indicate whether that State's air quality impact on downwind areas is sufficiently high to justify imposition of the 2010 (Phase I) controls, it does not justify imposition of the 2015 (Phase II) controls. Rather, according to the commenters, EPA should conduct further air quality modeling that evaluates the upwind State's 2015 base case emissions—taking into account the CAIR 2010 controls but not the CAIR 2015 controls—to determine whether the State continues (even after imposition of the CAIR 2010 controls) to have a sufficient downwind ambient impact to justify the 2015 controls.

Commenters added that, in their view, $PM_{2.5}$ precursors generally were decreasing after 2010, the $PM_{2.5}$ nonattainment problem was generally diminishing as well, and the contribution of some upwind States to downwind areas was relatively small. These facts, according to the commenters, indicated that some upwind States should not be subject to the 2015 reductions requirement.

Some commenters stated, more broadly, that the threshold contribution level selected by EPA should be considered a floor, so that upwind States should be obliged to reduce their emissions only to the level at which their contribution to downwind nonattainment does not exceed that threshold level.

Response: The EPA views the CAIR emission reduction requirements as a single action, but one that cannot be fully implemented in 2009 (for NO_X) or 2010 (for SO_2), and must instead be partially deferred until 2015, solely for reasons of feasibility. Under these circumstances, EPA does not believe it appropriate to re-evaluate the 2015 component, as commenters have suggested.

Under EPA's approach, which mirrors that of the NO_X SIP Call, EPA projects, for each upwind State, SO_2 and NO_X inventories, as of 2010, taking into account controls required under other CAA provisions and controls adopted by State and local agencies. The EPA then uses air quality modeling techniques to determine the impact of these emissions on downwind air quality. The EPA then requires upwind States whose emissions have a sufficiently high impact to eliminate the amount of their emissions that could be eliminated through application of highly cost-effective controls. These emissions reductions must be implemented as expeditiously as practicable. Were it feasible to implement all the reductions by 2009 (for NO_X) or 2010 (for SO_2), EPA would so require. Because part of the emissions reductions cannot feasibly be implemented until 2015, EPA is requiring today's two-phase approach. This analytic method is the same as for the NO_X SIP Call, except that in that rulemaking all of the required emissions reductions could feasibly be implemented in one phase.

As in the case of the NO_X SIP Call, EPA takes the view that once a State's emissions are determined to contribute to downwind nonattainment by at least a threshold amount, then the upwind State should reduce its emissions by the amount that would result from implementation of highly cost-effective controls. This approach is justified by the benefits of reducing the upwind contribution to downwind nonattainment, coupled with the relatively low costs. However, EPA does consider the ambient impacts of the required emissions reductions. For today's action, air quality modeling indicates that the regionwide emissions reductions do not reduce $PM_{2.5}$ levels beyond what is needed for attainment and maintenance. (See also section III below.) Most important for present purposes, as long as the controls yield downwind benefits needed to reduce the extent of nonattainment, the controls should not be lessened simply because they may have the effect of reducing the upwind State's contribution to below the initial threshold.

The DC Circuit, in upholding the NO_X SIP Call, rejected similar arguments to those raised by commenters (*Michigan* v. *EPA,* 213 F.3d at 679). In the NO_X SIP Call rulemaking, commenters argued that EPA's analytic approach to the ''contribute significantly'' test was flawed because it meant that States with different impacts downwind would nevertheless have to implement the same level of controls (*i.e.*, those that were highly cost effective). Commenters urged EPA to recast its approach by limiting an upwind State's emissions reductions to the point at which the remaining emissions no longer caused a downwind ambient impact above the threshold level for significance. (''Responses to Significant Comments on the Proposed Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group (OTAG) Region for Purposes of Reducing Regional Transport of Ozone (62 FR 60318; November 7, 1997 and 63 FR 25902; May 11, 1998),'' U.S. E.P.A. (September 1998), Docket Number A–96–56–VI–C–1, at 213–16.)

Petitioners challenging the NO_X SIP Call in *Michigan* v. *EPA* used the same arguments to contend that EPA's analytic approach in the NO_X SIP Call was arbitrary and capricious. The Court dismissed these arguments, stating:

> * * * EPA required that all of the covered jurisdictions, regardless of amount of contribution, reduce their NO_X by an amount achievable with ''highly cost-effective controls.'' Petitioners claim that EPA's uniform control strategy is irrational. * * * [T]hey observe that where two states differ considerably in the amount of their respective NO_X contributions to downwind nonattainment, under the EPA rule even the small contributors must make reductions equivalent to those achievable by highly cost-effective measures. This of course flows ineluctably from the EPA's decision to draw the ''significant contribution'' line on a basis of cost differentials. Our upholding of that decision logically entails upholding this consequence.

(*Michigan* v. *EPA,* 213 F.3d at 679.)

Thus, the Court approved EPA's approach of requiring the same control level on all affected States, without concern as to the arguably inconsistent ambient impacts that may result. By the same token, in today's action, EPA's approach should be accepted notwithstanding that the upwind controls could, at least in theory, result in an ambient impact that is below the initial threshold. For this reason, there is no basis to conduct a separate evaluation of the 2015 controls.

ii. Residual Nonattainment

Comment: A commenter expressed concern that too many areas will remain out of attainment for the $PM_{2.5}$ and 8-hour ozone NAAQS even after implementation of the CAIR rule.

Response: Section 110(a)(2)(D) of the CAA requires upwind States to prohibit the amount of emissions that contribute significantly to downwind nonattainment, but does not require the upwind States to prohibit sufficient emissions to assure that the downwind areas attain. Rather, downwind areas continue to bear the responsibility of addressing remaining nonattainment.

iii. Relationship of Reductions to Attainment Dates

Comment: Some commenters, who viewed the CAIR as imposing unduly light obligations on upwind States, argued that because States with nonattainment areas must develop SIPs that provide for attainment regardless of the cost of the requisite controls, and because the courts have viewed attainment deadlines as central to the CAA, EPA should require that upwind emissions contributing to downwind nonattainment must be eliminated by the downwind attainment dates, and not later.

Other commenters, who viewed the CAIR as imposing unduly heavy obligations on upwind States, argued that EPA had no authority to require upwind emissions reductions after the downwind attainment dates because by that time, the upwind emissions were no longer contributing to nonattainment. These commenters further argued that EPA has no authority to accelerate the emissions reductions because the controls could not feasibly be implemented by an earlier date.

Response: We note first that part of this issue is moot since EPA is requiring NO_X controls in 2009, within the statutory time periods for attainment. With respect to remaining issues, EPA's interpretation and application of the ''contribute significantly to nonattainment'' standard of section 110(a)(2)(D) is not necessarily constrained by the downwind area's attainment date in either manner suggested by the commenters.

First, although it is true that the nonattainment area requirements and deadlines in CAA title I, part D, mean that the downwind area must achieve attainment by its attainment date without regard to the feasibility of emissions reductions from sources in that nonattainment area, section 110(a)(2)(D) by its terms does not apply those constraints to sources in the upwind States. Rather, EPA's interpretation of the ''contribute significantly to nonattainment'' standard—which incorporates feasibility considerations in determining the implementation period for the upwind emissions controls—continues to apply.

Often, upwind emissions reductions affect at least several downwind areas with different attainment dates. The EPA does not read section 110(a)(2)(D) to require that the pace of upwind reductions be controlled by the earliest downwind attainment date. Rather, EPA views the pace of reductions as being determined by the time within which they may feasibly be achieved. In some cases, upwind sources are themselves in a nonattainment area that has a longer attainment date than the downwind area, and it may not be feasible for those upwind sources to implement reductions prior to the downwind attainment date. Therefore, the upwind emissions may be projected to continue to affect adversely nonattainment in the downwind area even after the downwind attainment date, in the manner described above. Further, emissions reductions after the attainment date may be important to prevent interference with maintenance of the standards.

The CAIR will achieve substantial reductions in time to help many nonattainment areas attain the standards by the applicable attainment dates. The design of the SO_2 program, including the declining caps in 2010 and 2015 and the banking provisions, will steadily reduce SO_2 emissions over time, achieving reductions in advance of the cap dates; and the 2009 and 2015 NO_X reductions will be timely for many downwind nonattainment areas. Although many of today's nonattainment areas will attain before all the reductions required by CAIR will be achieved, it is clear that CAIR's reductions will still be needed through 2015 and beyond. The EPA has determined that each upwind State's 2010 and 2015 emissions reductions will be necessary because, for purposes of both $PM_{2.5}$ and 8-hour ozone, we reasonably predict that a downwind receptor linked to that upwind State will either: (i) Remain in nonattainment and continue to experience significant contribution to nonattainment from the upwind State's emissions; or (ii) attain the relevant NAAQS but later revert to nonattainment due, for example, to continued growth of the emissions inventory. This is discussed in detail in section III below.

iv. Factors To Consider in Future Rulemaking

In the January and June CAIR proposals, we discussed regional control requirements and budgets based on a showing of ''significant contribution'' by upwind States to nonattainment in downwind States (69 FR at 4611–13, 32720). The CAA section 110(a)(2)(D), which provides the authority for CAIR, states among other things that SIPs must contain adequate provisions prohibiting, consistent with the CAA, sources or other types of emissions activity within a State from emitting pollutants in amounts that will ''contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to'' the NAAQS. In the CAIR, EPA has interpreted section 110(a)(2)(D) to require that certain States reduce emissions by specified amounts, and has determined those amounts based on the availability of highly cost effective controls for identified source categories. Following this interpretation, EPA has calculated CAIR's emissions reduction requirements based on the availability of highly cost-effective reductions of SO_2 and NO_X from EGUs in States that meet EPA's proposed inclusion criteria.

One approach cited in the January 2004 CAIR proposal for ensuring that both the air quality component and the cost effectiveness component of the section 110 ''contribute significantly'' determination is met, is to consider a source category's contribution to ambient concentrations above the attainment level in all nonattainment areas in affected downwind states. *Id.* In the June supplemental proposal, we requested comment on a further refinement of this concept—*i.e.*, whether a source category should be included in a broad regional rule promulgated pursuant to section 110(a)(2)(D) only if the proposed level of additional control of that category would meet a specified threshold. Under that approach, EPA said it might determine, for example, that in the context of a broad multi-state SIP call, emissions reductions from particular source category are ''highly cost effective'' only if emissions reductions from that source category would result in at least 0.5 percent of U.S. counties and/or parishes coming into attainment with a NAAQS. The EPA noted that, given the number of counties and parishes in the United States, this requirement would be met if at least 16 counties were brought into attainment with a NAAQS as a result of the proposed level of control on a particular source category.

The Agency received comments both supporting and opposing the adoption of this test as a part of the ''highly cost effective'' component of the ''contribute significantly'' requirement of CAA section 110(a)(2)(d). Commenters supporting this test asserted that it was consistent with the CAA's overall focus on State, rather than federal, control over which sources should be regulated, and also was consistent with ensuring that broad, regional SIP calls, such as the one at issue in this case, focus only on source categories the control of which will result in substantial overall improvements in air quality. Commenters opposing this screen with respect to the application of section 110(a)(2)(D) asserted, in general, that the test would be inconsistent with the analysis used by the Agency in the NO_X SIP call and with the language of section 110(a)(2)(D).

We have determined that it is not appropriate to adopt a statutory interpretation embodying a ''bright line'' rule that 0.5 percent of the U.S. counties and/or parishes must be brought from nonattainment into attainment from controlling emissions from a particular source category, in order for reductions from that source category to be considered highly cost effective. We continue to believe, however, that broad multi-state rules under section 110(a)(2)(D), such as the one we are finalizing today, should play a limited role under the CAA and must be justified by a careful evaluation of the air quality improvement that will result from the controls under consideration. Therefore, we intend to undertake any future broad, multi-state rulemakings under section 110(a)(2)(D) regarding transported emissions only when, as here, they produce substantial air quality benefits across a broad area and have beneficial air quality impacts on a significant number of downwind nonattainment areas, including bringing many areas into attainment. We do not at this time anticipate the need for any such rulemakings in the future. We believe that today's action, coupled with current and upcoming national rules and local or subregional programs adopted by States, will be sufficient to address the remaining nonattainment problems.

In evaluating whether to undertake national or regional transport rulemakings in the future, we believe it is not only appropriate but necessary to consider the effectiveness of the proposed emissions reductions in improving downwind air quality. We believe it will be reasonable to initiate a broad multi-state rulemaking under section 110(a)(2)(D) based on a determination that particular emissions reductions are highly cost effective only when those reductions will bring a significant number of downwind areas into attainment. In adopting this approach for determining whether a future broad, multi-state SIP call is appropriate, we note that other CAA mechanisms, such as SIP disapproval authority and State petitions under section 126, are available to address more isolated instances of the interstate transport of pollutants.

The EPA projects that control of SO_2 and NO_X through CAIR will bring 72 counties into attainment with the $PM_{2.5}$ and ozone NAAQS. The total number represents approximately 3 percent of the counties/parishes in the United States, and is clearly a significant number of areas. What will be considered a significant number of areas in any future cases will need to be determined on a case-by-case basis.

III. Why Does This Rule Focus on SO_2 and NO_X, and How Were Significant Downwind Impacts Determined?

This section discusses the basis for EPA's decision to require reductions in upwind emissions of SO_2 and NO_X to address $PM_{2.5}$ transport and to require reductions in upwind emissions of NO_X to address ozone-related transport. In addition, this section discusses how EPA determined which States are subject to today's rule because their sources' emissions will significantly contribute to nonattainment of the $PM_{2.5}$ or 8-hour ozone standards, or interfere with maintenance of those standards, in downwind States. The EPA assessed individual upwind States' ambient impacts on downwind States and established a threshold value to identify those States whose impact constitutes a significant contribution to air quality violations in the downwind States. The EPA used air quality modeling of emissions in each State to estimate the ambient impacts. The technical issues concerning the modeling platform and approach are discussed in section VI, Air Quality Modeling Approach and Results. Also, EPA considered the potential for upwind state emissions to interfere with maintenance of the $PM_{2.5}$ and 8-hour ozone NAAQS in downwind areas.

A. What Is the Basis for EPA's Decision To Require Reductions in Upwind Emissions of SO_2 and NO_X To Address $PM_{2.5}$ Related Transport?

1. How Did EPA Determine Which Pollutants Were Necessary To Control To Address Interstate Transport for $PM_{2.5}$?

a. What Did EPA Propose Regarding This Issue in the NPR?

Section II of the January 2004 proposal summarized key scientific and technical aspects of the occurrence, formation, and origins of $PM_{2.5}$, as well as findings and observations relevant to formulating control approaches for reducing the contribution of transport to fine particle problems (69 FR 4575–87). Key concepts and provisional conclusions drawn from this discussion can be summarized as follows: [17]

(1) Fine particles (measured as $PM_{2.5}$ for the NAAQS) consist of a diverse mixture of substances that vary in size, chemical composition, and source. The $PM_{2.5}$ includes both ''primary'' particles that are emitted directly to the atmosphere as particles, and ''secondary'' particles that form in the atmosphere through chemical reactions from gaseous precursors. The major components of fine particles in the Eastern U.S. can be grouped into five categories: carbonaceous material (including both primary and secondary organic carbon and black carbon), sulfates, nitrates, ammonium, and crustal material, which includes suspended dust as well as some other directly emitted materials. The major gaseous precursors of $PM_{2.5}$ include SO_2, NO_X, ammonia (NH_3), and certain volatile organic compounds.

(2) Examination of urban and rural monitors indicate that in the Eastern U.S., sulfates, carbonaceous material, nitrates, and ammonium associated with sulfates and nitrates are typically the largest components of transported $PM_{2.5}$, while crustal material tends to be only a small fraction.

(3) Atmospheric interactions among particulate ammonium sulfates and nitrates and gas phase nitric acid and ammonia vary with temperature, humidity, and location. Both ambient observations and modeling simulations suggest that regional SO_2 reductions are effective at reducing sulfate and associated ammonium, and, therefore, $PM_{2.5}$. Under certain conditions reductions in particulate ammonium sulfates can release ammonia as a gas, which then reacts with gaseous nitric acid to form nitrate particles, a phenomenon called ''nitrate replacement.'' In such conditions SO_2 reductions would be less effective in reducing $PM_{2.5}$, unless accompanied by reductions in NO_X emissions to address the potential increase in nitrates.

(4) Reductions in ammonia can reduce the ammonium, but not the sulfate portion of sulfate particles. The relative efficacy of reducing nitrates through NO_X or ammonia control varies with atmospheric conditions; the highest particulate nitrate concentrations in the East tend to occur in cooler months and regions. At present, our knowledge about sources, emissions, control approaches, and costs is greater for NO_X than for ammonia. Existing programs to reduce NO_X from stationary and mobile sources are well underway. From a chemical perspective, as NO_X reductions accumulate relative to ammonia, the atmospheric chemical system would move towards an equilibrium in which ammonium nitrate reductions become more responsive to further NO_X reductions relative to ammonia reductions.

(5) Much less is known about the sources of regional transport of carbonaceous material. Key uncertainties include how much of this material is due to biogenic as compared to anthropogenic sources, and how much is directly emitted as compared to formed in the atmosphere.

(6) Observational evidence suggests that the substantial reductions in SO_2 emissions in the eastern U.S. since 1990 have indeed caused observed reductions in $PM_{2.5}$ sulfate. The relatively small historical reductions in NO_X emissions do not allow observations to be used similarly to test the effectiveness of NO_X reductions.

Based on the understanding of current scientific and technical information, as well as EPA's air quality modeling, as summarized in the January 30 proposal, EPA concluded that it was both appropriate and necessary to focus on control of SO_2 and NO_X emissions as the most effective approach to reducing the contribution of interstate transport to $PM_{2.5}$.

The EPA proposed not to control emissions that affect other components of $PM_{2.5}$, noting that ''current information relating to sources and controls for other components identified

[17] More complete discussions of the key scientific underpinnings that form the basis of these conclusions in the proposal and the discussion of these issues in this seciton of today's notice can be found in the recently completed EPA Criteria Document (USEPA, National Center for Environmental Assessment, Air Quality Criteria for Particulate Matter, October 2004) and the NARTSO assessment of fine participles (NARSTO, Particulate Matter Science for Policy Makers—A NARSTO ASSESSMENT, February 2003).

in transported $PM_{2.5}$ (carbonaceous particles, ammonium, and crustal materials) does not, at this time, provide an adequate basis for regulating the regional transport of emissions responsible for these $PM_{2.5}$ components.'' (69 FR 4582). For all of these components, the lack of knowledge of and ability to quantify accurately the interstate transport of these components limited EPA's ability to include these components in this rule.

b. How Does EPA Address Public Comments on Its Proposal To Address SO_2 and NO_X Emissions and Not Other Pollutants?

i. Overview of Comments on This Issue

A large number of commenters including states, affected industries, environmental groups, academics, and other members of the public agreed with EPA's proposal to require cost-effective multipollutant reductions of SO_2 and NO_X to address interstate transport contributions to $PM_{2.5}$ problems. Fewer commenters who supported controlling SO_2 and NO_X commented on inclusion of additional pollutants, but several also agreed that it would be premature at this time to require control of emissions of other chemical components and precursors to address such transport. These commenters suggested that SO_2 and NO_X emissions from EGUs and other sources indeed contribute significantly to downwind $PM_{2.5}$. They argued that control of other components is premature because of a lack of knowledge, either about the interstate contributions of other components or of control measures for these components. Generally, EPA accepts and agrees with these conclusions.

A number of commenters disagreed to varying degrees with part or all of EPA's proposed focus on SO_2 and NO_X. The main points raised by these commenters can be grouped as follows:

(1) The focus on SO_2 and NO_X is not appropriate because sulfates and nitrates may not be (or are not) the most important determinants of the health effects of $PM_{2.5}$.

(2) The EPA should mandate, or at least permit, states to control other precursors and particle emissions in addition to, or instead of, SO_2 and NO_X. Commenters sometimes made specific recommendations with respect to additional pollutants, including carbonaceous (including organic) particles and precursors, ammonia, and other direct emissions, including crustal material.

(3) The focus on SO_2 may be appropriate, but the basis for requiring NO_X control is not clear.

ii. Summary of EPA's Response to the Major Comments on This Issue

The following subsections summarize both key comments and EPA's responses organized by the major categories outlined above. As noted in Section I, EPA has developed and placed in the rulemaking docket a detailed response to these and other public comments.

(a) SO_2 and NO_X May Be Less Important to Health Than Other Transport-Related Components

Comment: Several commenters argued that the proposed focus on SO_2 and NO_X was premature, citing the potential for differential toxicity of various $PM_{2.5}$ components, and in some cases advancing evidence (*e.g.,* the Electric Power Research Institute Aerosol Research and Inhalation Studies [ARIES]) [18] that other components such as organic particles appear to be more responsible for health effects of particles than sulfates and nitrates. Several argued that the relative contribution of components to health impacts is an important uncertainty that should be researched more carefully before proposing to control only SO_2 and NO_X.

Response: Today's rulemaking establishes requirements for SIP submissions under section 110(a)(2)(D). Those SIP submissions must prohibit emissions that contribute significantly to nonattainment of a NAAQS in a downwind State. The EPA determined in the 1997 rulemaking promulgating the $PM_{2.5}$ NAAQS that specified levels of $PM_{2.5}$ adversely affect human health, and that sulfates and nitrates are components of $PM_{2.5}$ (62 FR 38652, July 18, 1997). SO_2 and NO_X, in turn, are precursors to fine particulate sulfates and nitrates. Comments that sulfates and nitrates do not cause adverse health effects are more appropriately raised in the context of past or ongoing reviews of the PM NAAQS. Because today's action forms part of implementing and not establishing the PM NAAQS, comments relating to the evidence supporting or not supporting health effects of all or portions of pollutants regulated by the $PM_{2.5}$ NAAQS are not germane to this rulemaking.

Nevertheless, we discuss briefly EPA's current response regarding the contributions of different components of $PM_{2.5}$ to health effects. In establishing the current $PM_{2.5}$ NAAQS, EPA found that there was ample evidence to associate various health effects with the measured mass concentration of particles smaller than a nominal 2.5 micrometers (um), termed $PM_{2.5}$. The EPA recognizes that the toxicity of different chemical components of $PM_{2.5}$ may vary, and that the observed effects may be the result of the mixture of particles and gases. While research is underway to better identify whether some chemical components are more responsible for health effects than others, results now available from such research are limited and inconclusive. A number of studies included in the recent EPA PM criteria document [19] have found effects to be associated with one or more of the major components and sources of $PM_{2.5}$, including sulfates, nitrates, organic materials, $PM_{2.5}$ mass, coal combustion, and mobile sources. The criteria document concludes that these studies suggest that many different chemical components of fine particles and a variety of different types of source categories are all linked to premature mortality and other serious health effects, either independently or in combinations, but that it is not possible to reach clear conclusions about differential effects of PM components. Accordingly, individual studies or groups of studies such as ARIES cannot be used to single out any particular component of $PM_{2.5}$ as wholly responsible (or not at all responsible) for the array of health effects that have been found to be associated with various chemical and mass indicators of fine particles. Other Federal agencies and EPA continue to promote and support the epidemiological and toxicological studies needed to better understand the effects of different chemical components and different size particles on health effects.

In the meantime, EPA believes that, given the substantial evidence of significant health effects of fine particles, it is important to move forward expeditiously to address both transported and local sources of all the major components of fine particles in an effort to implement and attain the $PM_{2.5}$ standards. Today's rule is focused on the contribution of interstate transport of nitrate and sulfates to $PM_{2.5}$ in nonattainment areas. However, EPA has already adopted other rules that are reducing emissions and exposures to these and other major components of fine particles on a national, regional, and local basis. Recent national mobile

[18] R. J. Klemm, *et al.,* ''Daily Mortality and Air Pollution in Atlanta: Two Year of Data from ARIES'' (accepted, Inhalation Toxicology).

[19] USEPA, National Center for Environmental Assessment, Air Quality Criteria for Particulate Matter, October 2004.

rules and programs, in particular, have focused on carbonaceous materials emitted from gasoline and both highway and non-road diesel powered mobile sources (65 FR 6698; 66 FR 5002; 69 FR 38958). States with nonattainment areas will also be required to address local sources of $PM_{2.5}$ in order to meet progress and attainment requirements. Together, the collective effect of these programs ensures a balanced approach to reducing all of the major components of $PM_{2.5}$ from transported and local sources.

(b) Inclusion of Other $PM_{2.5}$ Precursors and Components

Comment: A number of commenters recommended that EPA either mandate or at least permit controls on the emissions that cause interstate transport of other components of $PM_{2.5}$, in addition to or as a substitute for, SO_2 and NO_X controls. Several commenters recommended that EPA include emissions reductions related to the components of $PM_{2.5}$ other than sulfate and nitrate. While many commenters suggested addressing all of the important contributors to $PM_{2.5}$, including those not regulated under this Rule, others highlighted only one or two additional components as most important to include. Of the $PM_{2.5}$ components, direct emissions and precursors to carbonaceous $PM_{2.5}$ and ammonia emissions were the omitted contributors most frequently discussed.

Some of these commenters argued that, by limiting the rule to SO_2 and NO_X and excluding other sources of ambient $PM_{2.5}$, EPA would be limiting the choices that states have to address their downwind interstate transport contributions. These commenters argued that this limitation is contrary to the CAA, which generally gives states the discretion to choose their own emission control strategies. Commenters further asserted that the roles of other components in $PM_{2.5}$ are sufficiently well understood that they should be included in state SIPs for $PM_{2.5}$ transport, and could partially satisfy the $PM_{2.5}$ reductions anticipated by this rule.

Response: The three main classes of $PM_{2.5}$ precursors that are not included in this rulemaking are carbonaceous material (including both primary emissions and VOC emissions that form secondary organic aerosol), ammonia, and crustal material. As noted in the proposal(69 FR 4576) and as mentioned in several comments, these components comprise a measurable faction of $PM_{2.5}$ throughout the Eastern U.S., and the contribution of carbonaceous material, in particular, is often substantial. In addition, emissions contributing to these components in one state likely do affect $PM_{2.5}$ concentrations in other states to some extent. However, the extent of those downwind contributions to nonattainment has not been quantified adequately and current scientific understanding makes such a determination more uncertain than is the case for SO_2 and NO_X. Responses to recommendations for including each of these three classes in the transport rule are summarized below.

(i) Carbonaceous Material

For carbonaceous material, uncertainties in both the quantity and origins of emissions contributing to both primary and secondary carbonaceous material on regional scales (including emissions from fires and from biogenic sources) limit the quality of regional scale modeling of carbonaceous $PM_{2.5}$. This in turn causes substantial uncertainties in determining the amount of interstate transport from carbonaceous material and of the costs and effectiveness of emission controls. Modeling and monitoring the relative amount of organic particles that come from the formation of secondary organic particles, versus primary organic particles, is also highly uncertain.

In addition, comparison of urban and nearby rural PM composition monitors [20] in the eastern U.S. find a significantly larger amount of carbonaceous materials in urban areas as compared to rural areas, suggesting that a substantial fraction of carbonaceous particles in urban areas come from local sources. By contrast, urban and non-urban monitors in the East show greater homogeneity for regional sulfate concentrations as compared to carbonaceous materials, suggesting regional sources are most important for sulfates. Results for nitrates suggest both a mixture of regional and local sources. Furthermore, as noted above and in the proposal (69 FR 4577–78), while the relative contributions of different sources to regional sulfate and nitrates can be quantified with certainty, the contributions of different sources to carbonaceous materials on a regional scale are less clear. Moreover, as noted in the NPR preamble, some research into mechanisms of formation of organic particles suggests that both NO_X and SO_2 reductions might be of some benefit in lowering the amount of secondary organic particles.[21] Current models are not, however, capable of quantifying such potential benefits.

While EPA does not believe that enough is known about the relative effectiveness or costs of reducing anthropogenic sources of carbonaceous particles on transported $PM_{2.5}$, EPA agrees that control of known source categories of these materials can have a significant benefit in reducing the significant local contribution. For this reason, EPA has already enacted other national rules that will reduce emissions of primary carbonaceous $PM_{2.5}$ from mobile sources, the largest contributor to such emissions. In addition to reducing $PM_{2.5}$ in nonattainment areas, these regulations will also have the benefit of reducing a large measure of whatever interstate transport of carbonaceous $PM_{2.5}$ occurs.

(ii) Ammonia

While current models are able to address the major chemical mechanisms involving particulate ammonium compounds, regional-scale ammonia emissions, particularly from agricultural sources, are highly uncertain.[22] Given the relative lack of experience in controlling such sources, the costs and effectiveness of actions to reduce regional ammonia emissions are not adequately quantified at present. As noted above, ammonium would not exist in $PM_{2.5}$ if not for the presence of sulfuric acid or nitric acid; hence, decreases in SO_2 and NO_X can be expected ultimately to decrease the ammonium in $PM_{2.5}$ as well. The additional regional limits on SO_2 and NO_X emissions outlined in today's notice added to those reductions provided under current programs would likewise be expected to reduce the $PM_{2.5}$ effectiveness of any ammonia control initiative.[23] Unlike ammonium, sulfuric acid has a very low vapor pressure and would exist in the particle with or without ammonia. Therefore, while SO_2 reductions would reduce particulate ammonium, changes in ammonia would

[20] V. Rao, N. Frank, A. Rush, F. Dimmick. Chemical Speciation of $PM_{2.5}$ in Urban and Rural Area, in The Proceedings of the Air & Waste Management Association Symposium on Air Quality Measurement Methods and Technology, San Francisco, November 13–1, 2002.

[21] Jang, M; Czoschke, N.M.; Lee, S.: Kamens, R.M., Heterogeneous Atmospheric Aerosol Production by Acid-Catalzyed Particle Phase Reactions, Science, 2002, 298: 814–817.

[22] Battye, W., V.P. Aneja, and P.A. Roelle, Evaluation and improvement of ammonia emissions inventories, Atmospheric Environment, 2003, 37: 3873–3883.

[23] As pointed out by one commenter, a hypothetical new program resulting in major regional reductions of ammonia would reduce the effectiveness of NO_X controls. However, given the uncertainties in emissions, the dispersed nature of ammonia sources and the lack of present controls, an effort to develop a new regional ammonia program would likely take significantly longer than the additional NO_X reductions EPA is adopting today.

be expected to have very little effect on the sulfate concentration.

In addition to the above considerations, because ammonium nitrates are highest in the winter, when ammonia emissions are lowest, reducing wintertime NO_X emissions may represent a more certain path towards reducing this winter peak than ammonia reductions. Moreover, reductions in ammonia emissions alone would also tend to increase the acidity of $PM_{2.5}$ and of precipitation. As noted in the proposal, this might have untoward environmental or health consequences.

Some commenters highlighted ammonia as an important pollutant with multiple effects on the environment, including its contributions to $PM_{2.5}$. These commenters highlighted that ammonia emissions are not currently regulated extensively, and suggested that EPA strengthen its efforts to better understand the many effects of ammonia emissions and better research options for controlling ammonia, so that it can be regulated where appropriate in the future programs. Generally, EPA agrees with these commenters.

(iii) Crustal Material

The contributions of crustal materials to $PM_{2.5}$ nonattainment are usually small, and the interstate transport of crustal materials is even smaller. Emissions of crustal materials on regional scales are uncertain, highly variable in space and time, and may not be easily controlled in some cases, suggesting significant uncertainties in quantifying emissions and the costs and effectiveness of control actions. Emissions reductions of SO_2 and NO_X will likely reduce some of the direct emissions of $PM_{2.5}$ from EGUs and other industries, which are responsible for a portion of the ''crustal material'' measured downwind at receptors.

(c) Summary of Response To Requiring or Allowing Reductions in Other Pollutants

After reviewing public comments in light of the current understanding of alternative pollutants as summarized above, EPA disagrees with those commenters who suggested that the final Clean Air Interstate Rule should require states to address the interstate transport of carbonaceous material (including VOCs), ammonia, and/or crustal material in the present rulemaking.

At present, the sources and emissions contributing to these components on regional scales are not sufficiently quantified. In addition, the representation of atmospheric physics and chemistry for these components in air quality models is in some cases poor in comparison with current understanding of SO_2 and NO_X (most notably for sources and amounts of secondary organic aerosol production.[24] Consequently, quantification of the interstate transport of these components is significantly more uncertain than for SO_2 and NO_X emissions. Given these uncertainties in regional emissions and interstate transport of these components, EPA has determined that it would be premature to quantify interstate impacts of these emissions through zero-out modeling, as was done for SO_2 and NO_X emissions.

In addition, the costs of control measures, their effectiveness at reducing emissions, as well as their ultimate effectiveness at reducing $PM_{2.5}$ concentrations at downwind receptors are all uncertain. The EPA does not believe it could reasonably evaluate whether such State emissions contributed significantly to transport, or what level of control would address the significant contribution. Commenters have not provided us specific data and information to allow such assessments.

The EPA also disagrees with commenters who argue that EPA should, for the purposes of this rule, permit the States to substitute controls of sources of any of these other three components for the required limits on SO_2 and NO_X. Given the greater uncertainties in estimating the contribution of alternative source emissions, States would have difficulty developing, and EPA would have difficulty in approving, SIPs that, by controlling these components, purport to reduce an upwind State's impact on downwind $PM_{2.5}$ nonattainment by an equivalent amount to that required in today's final rule.

As explained in the proposal, a decision not to regulate these components of $PM_{2.5}$ in the present rulemaking does not preclude state or local $PM_{2.5}$ implementation plans from reducing emissions of carbonaceous material, ammonia, or crustal material, in order to achieve attainment with $PM_{2.5}$ standards, in cases where there is evidence that such controls will be effective on a local basis. Although uncertainties exist in addressing long-range transport of these pollutants, state and local air quality management agencies will need to evaluate reasonable control measures for sources of these pollutants in developing SIPs due in 2008. We expect continuous improvements will be made in our understanding of source emissions and $PM_{2.5}$ components not addressed under CAIR. To assist future air quality management decisions, EPA is actively supporting research into better understanding the emissions, atmospheric processes, long range transport, and opportunities for control of these $PM_{2.5}$ components.

(d) Justification for Including NO_X in Determining Significant Contributions and for Regulating NO_X Emissions for $PM_{2.5}$ Transport

Some commenters questioned the EPA's basis for requiring emissions reductions of NO_X, in addition to SO_2, for the purposes of controlling interstate transport of $PM_{2.5}$. These comments, and EPA's response, are discussed below. Other comments addressing EPA's basis for requiring NO_X for ozone are addressed in a subsequent section.

Like SO_2, NO_X emissions are understood to affect $PM_{2.5}$ on regional scales, due in part to the time needed to convert NO_X emissions to nitrate. Like SO_2 but unlike precursors of other components of $PM_{2.5}$, emissions of NO_X are well quantified for EGUs and with reasonable accuracy for other urban and regional sources, and the transport of NO_X and $PM_{2.5}$ derived from NO_X can also be quantified with a fair degree of certainty. In addition, SO_2 and NO_X interact as part of the same chemical system in the atmosphere. Controlling SO_2 emissions without concurrently controlling NO_X emissions can lead to nitrate replacement whereby SO_2 emissions reductions will be less effective than expected. Finally, SO_2 and NO_X share common sources in fossil fuel combustion. As such, controlling emissions of both precursors in a coordinated way presents opportunities to reduce the overall cost of the control program.[25]

Commenters questioned EPA's methodology of evaluating whether an upwind State contributes significantly to $PM_{2.5}$ nonattainment by considering (through the ''zero-out'' air quality modeling technique) SO_2 and NO_X emissions simultaneously. These commenters argued that zeroing out SO_2 and NO_X emissions simultaneously precludes determining the contribution of each component to downwind nonattainment. Because sulfates generally comprise a greater fraction of $PM_{2.5}$ than nitrates in the Eastern U.S., these commenters argued that the basis for requiring NO_X controls is weaker than for SO_2, and has not been determined directly by EPA.

[24] EPA OAQPS CMAQ Evaluation for 2001 Docket # OAR–2003–0053–1716.

[25] NARSTO, Particulate Matter Science for Policy Makers—A NARSTO Assessment, February 2003.

The EPA's multi-pollutant approach of modeling SO_2 and NO_X contributions at the same time is consistent both with sound science and with the requirements of CAA section 110(a)(2)(D), as EPA interpreted and applied them in the NO_X SIP Call. This provision requires each State to submit a SIP to prohibit ''any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will * * * contribute significantly to nonattainment'' downwind. As discussed in section II above, in the NO_X SIP Call, a rulemaking in which EPA regulated NO_X emissions as precursors for ozone, EPA found that ozone resulted from the combined contributions of many emitters over a multistate region, a phenomenon that EPA termed ''collective contribution'' (63 FR 57356–86). As a result, EPA evaluated each State's contribution to nonattainment downwind by considering the impact of the entirety of that State's NO_X emissions on downwind nonattainment. Once EPA determined the State's entire NO_X emissions inventory to have at least a minimum downwind impact, then EPA required the State to eliminate the portion of those emissions that could be reduced through highly cost-effective controls. The EPA considered this approach to be consistent with the section 110(a)(2)(D) requirements.

In a companion rulemaking, the section 126 Rule, EPA found that certain, individual NO_X emitters must be subject to Federal regulation due to their impact on downwind nonattainment (65 FR 2674). The EPA based this finding on the same notion of ''collective contribution,'' that is, NO_X emissions from those individual sources were part of the upwind State's total NO_X inventory, the total NO_X inventory had a sufficiently high impact on downwind nonattainment, and therefore the individual NO_X emitters should be subject to control without any separate determination as to their individual impacts on downwind nonattainment.

The DC Circuit accepted EPA's collective contribution approach upholding most of the NO_X SIP Call regulation, in *Michigan* v. *EPA,* 213 F.3d 663 (DC Cir. 2000), *cert. denied* 532 U.S. 904 (2001). Similarly, the DC Circuit upheld most aspects of EPA's Section 126 Rule, including the collective contribution basis for finding that emissions from the individual sources should be subject to regulation. *Appalachian Power Co.* v. *EPA,* 249 F.3d 1032 (DC Cir. 2001) (per curium).

As discussed elsewhere, $PM_{2.5}$ is similar to ozone in that it is the result of emissions from many sources over a multi-state region. Accordingly, EPA considers that the phenomenon of ''collective contribution'' is associated with $PM_{2.5}$ as well.

In the CAIR NPR, EPA selected SO_2 and NO_X as the appropriate precursors to be controlled for $PM_{2.5}$ transport, for several reasons presented above. As in the NO_X SIP Call, today's rulemaking, under CAA section 110(a)(2)(D), requires EPA to evaluate whether a particular upwind State must submit a SIP that prohibits ''any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will * * * contribute significantly to nonattainment'' downwind. In making this determination, EPA considers the effects of all of the appropriate precursors—here, both SO_2 and NO_X—from all of the State's sources on downwind $PM_{2.5}$ nonattainment. If that collective contribution to downwind $PM_{2.5}$ nonattainment is sufficiently high, then EPA requires the upwind State to eliminate those precursors to the extent of the availability of highly cost-effective controls.

The EPA's approach to evaluating a State's impact on downwind nonattainment by considering the entirety of the State's SO_2 and NO_X emissions is also consistent with the chemical interactions in the atmosphere of SO_2 and NO_X in forming $PM_{2.5}$. The contributions of SO_2 and NO_X emissions are generally not additive, but rather are interrelated due to the nitrate replacement phenomenon, as well as other complex chemical reactions that can include organic compounds as well. As commenters point out, the nature of these reactions can vary with location and time. The non-linear nature of some of these reactions can produce differing results depending on the relative amount of reductions and copollutants. Reductions in sulfates can increase nitrates and, in some conditions, modest reductions in nitrates can increase sulfates although through different mechanisms. Large regional reductions in both pollutants, however, are more likely to result in a significant reductions in fine particles.[26]

Based on its current understanding of regional air pollution and modeling results, EPA believes that adopting a broad new program of regional controls to continue the downward trajectory in both SO_X and NO_X begun in base programs such as the national mobile source rules and Title IV, as well as the NO_X SIP call, will ultimately result in significant benefits not only in reducing $PM_{2.5}$ nonattainment, but improving public health, reducing regional haze, and addressing multimedia environmental concerns including acid deposition and nutrient loadings in sensitive coastal estuaries in the East.[27]

Some commenters argued that the benefits of combining NO_X with SO_2 reductions, if any, would be small, and further argued that the effect of any nitrate reductions in the environment would be further diminished by measurement losses that can occur in the filter in the method used to measure $PM_{2.5}$. In so doing, they questioned the scientific basis for nitrate replacement, suggesting that this response to changes in SO_2 emissions may not happen in all places and at all times. The commenters referenced a study in the Southeastern U.S. by Blanchard and Hidy,[28] which they claim calls into question whether nitrate replacement actually occurs. In fact, the study finds evidence that nitrate replacement occurs: ''the sulfate decreases were an input to the model calculations, but their effect on fine PM mass was modified by concomitant decreases in ammonium and increases in nitrate.'' A second study by the same authors, using essentially the same dataset and methods, and referenced both by EPA in the NPR and by the commenters, gives very strong support for the existence of nitrate replacement, as well as for coordinating SO_2 and NO_X reductions, as indicated by the following conclusions: ''reductions in sulfate through SO_2 reduction at constant NO_X levels would not result in proportional reduction in $PM_{2.5}$ mass because particulate nitrate concentrations would increase. However, if both NO_X and SO_2 emissions are reduced, then it may be possible to achieve sulfate reductions without concomitant nitrate increases * * *''[29]

Nitrate replacement is well documented in the scientific literature as a possible response of $PM_{2.5}$ to changes in SO_2 emissions.[30] While these commenters are correct that nitrate replacement is not expected to occur at all places and at all times, even where average conditions are not favorable for

[26] NARSTO, Particulate Matter Science for Policy Makers—A NARSTO Assessment, February 2003.

[27] ''Regulatory Impact Analysis for the Final Clean Air Interstate Rule (March 2005).''

[28] Blanchard, C.L., and G.M. Hidy (2004) Effects of projected utility SO_2 and NO_X emission reductions on particulate nitrate and $PM_{2.5}$ mass concentrations in the Southeastern United States, Report to Southern Company. See CAIR docket.

[29] Blanchard C.L., and G.M. Hidy (2003). Effects of changes in sulfate, ammonia, and nitric acid on particulate nitrate concentrations in the Southeastern United States, J. Air & Waste Manage. Assoc., 53: 283–290.

[30] NARSTO, Particulate Matter Science for Policy Makers—A NARSTO Assessment, February 2003.

nitrate replacement, hourly variability in those conditions can create conditions favorable for nitrate replacement at particular times. Nitrate replacement theory predicts no conditions under which SO_2 reductions would decrease nitrate, and suggests that nitrate may increase under fairly common conditions.[31] Consequently, the net effect of SO_2 reductions can be only to increase nitrate or not to have any effect. The variability of conditions occurring over a year means that SO_2 reductions would be expected to increase nitrate on balance.

Even if the studies referenced by these commenters showed that nitrate replacement does not occur in some circumstances, other studies suggest that the conditions for nitrate replacement are common in the Eastern U.S.[32] Suggesting that nitrate replacement does not occur under some conditions does not imply that NO_X should not be controlled, when it is known that nitrate replacement occurs under other common conditions.

The EPA recognizes that the relative reductions in $PM_{2.5}$ from implementation of the CAIR will be greater for SO_2 than for NO_X. Nevertheless, overall costs for reducing NO_X in the CAIR region are much lower than SO_2 because a large portion of the region has already installed NO_X controls for ozone in the summer months. Our revised modeling approaches took into account the differences commenters note between actual nitrate concentrations in the atmosphere and what is measured as $PM_{2.5}$. Nevertheless emissions of both pollutants clearly contribute to interstate transport of ambient fine particles, and EPA concludes that the best approach in this situation is to provide highly cost effective reductions for both pollutants. Moreover, in warmer conditions when apparent nitrate changes from NO_X reductions as measured on $PM_{2.5}$ monitors are small, the actual reductions in particulate and gaseous nitrates in the ambient environment are larger; accordingly, NO_X reductions combined with SO_2 reductions can be expected to reduce health risk, visibility impairment, and other environmental damages.

c. What Is EPA's Final Determination?

After considering the public comments, EPA concludes that it should adopt the approach it proposed for addressing interstate transport of pollutants that affect $PM_{2.5}$, for the reasons presented here and in the proposal. That is, in today's action, EPA is requiring states to take steps to control emissions of SO_2 and NO_X on the basis of their contributions to nonattainment of $PM_{2.5}$ standards in downwind states. The EPA concludes that we do not now have a sufficient basis for including emissions of other components (carbonaceous material, ammonia, and crustal material) that contribute to $PM_{2.5}$ in determining significant contributions and in requiring emission reductions of these components.

2. What Is the Role for Local Emissions Reduction Strategies?

a. Summary of Analyses and Conclusions in the Proposal

In section IV.F of the proposed rule, we discussed two analyses that were completed to address the impact of local control measures relative to regional reductions of SO_2 and NO_X (69 FR 4596–99). In the first analysis, we applied a list of readily identifiable control measures (NPR, Table IV–5) in the Philadelphia, Birmingham, and Chicago urban primary metropolitan statistical areas (PMSA) counties. In the second analysis, we applied a similar list of control measures to 290 counties representing the metropolitan areas we projected to contain any nonattainment county in 2010 in the baseline scenario. The three-city analysis estimated that these local measures would result in ambient $PM_{2.5}$ reductions of about 0.5 $\mu g/m^3$ to about 0.9 $\mu g/m^3$, which is less than needed to bring any of the cities into attainment in 2010. The 290-county study, which included enough counties to produce regional as well as local reductions, found that while some of the 2010 nonattainment areas would be projected to attain, many would not. Moreover, much of the $PM_{2.5}$ reduction in the 290-county study resulted from assuming reduction in sulfates due to SO_2 reductions on utility boilers in the urban counties. Accordingly, we concluded that for a sizable number of $PM_{2.5}$ nonattainment areas it will be difficult if not impossible to reach attainment unless transport is reduced to a much greater degree than by the simultaneous adoption of controls within only the nonattainment areas.

b. Summary and Response to Public Comments

A number of commenters supported EPA's conclusion that regional reductions are necessary given the difficulty in achieving local emission reductions, and given that they are generally more cost-effective. Generally, EPA agrees with these commenters.

Other commenters were critical of the local measures analysis, and recommended that EPA should consider a more appropriate mix of regional and local controls before requiring substantial expenditures for controls on power plants or other regional sources potentially affected by this rule. These commenters believed that the proposed rule did not represent the optimal emissions reduction strategy. Other commenters believed that the local measures analysis underestimated the achievable local emissions reductions. Some commenters believed that EPA should include local control measures in the baseline scenario for the analysis. Finally, some commenters questioned the feasibility of doing a local measures analysis at all, given the uncertainties in the analysis, the uncertainties regarding nonattainment boundaries, and the work to be done by State and local areas to identify and evaluate strategies.

The EPA continues to conclude that it would be difficult if not impossible for many nonattainment areas to reach attainment through local measures alone, and EPA finds no information in the comments to alter this conclusion. While recognizing the uncertainties in conducting such an analysis (as noted in the preamble to the proposed rule), we continue to believe that the two local measures scenarios represent a highly ambitious set of measures and emissions reductions that may in fact be difficult to achieve in practice. This analysis was not intended to precisely identify local measures that may be available in a particular area. The EPA believes that a strategy based on adopting highly cost effective controls on transported pollutants as a first step would produce a more reasonable, equitable, and optimal strategy than one beginning with local controls. The local measures analyses we conducted were not, however, intended to develop a specific or ''optimal'' regional and local attainment strategy for any given area. Rather, the analysis was intended to evaluate whether, in light of available local measures, it is likely to be necessary to reduce significant regional transport from upwind states. We continue to believe that the two local measures analyses that were conducted for the proposal rule strongly support the need for regional reductions of SO_2 and NO_X.

[31] Ibid.

[32] For example, West, J.J., A.S. Ansari, and S.N. Pandis (1999) Marginal $PM_{2.5}$, nonlinear aerosol mass response to sulfate reductions in the Eastern U.S., J. Air & Waste Manage. Assoc., 49: 1415–1424.

B. What Is the Basis for EPA's Decision To Require Reductions in Upwind Emissions of NO_X To Address Ozone-Related Transport?

1. How Did EPA Determine Which Pollutants Were Necessary To Control To Address Interstate Transport for Ozone?

In the notice of proposed rulemaking, EPA provided the following characterization of the origin and distribution of 8-hour ozone air quality problems:

The ozone present at ground level as a principal component of photochemical smog is formed in sunlit conditions through atmospheric reactions of two main classes of precursor compound: VOCs and NO_X (mainly NO and NO_2). The term ''VOC'' includes many classes of compounds that possess a wide range of chemical properties and atmospheric lifetimes, which helps determine their relative importance in forming ozone. Sources of VOCs include man-made sources such as motor vehicles, chemical plants, refineries, and many consumer products, but also natural emissions from vegetation. Nitrogen oxides are emitted by motor vehicles, power plants, and other combustion sources, with lesser amounts from natural processes including lightning and soils. Key aspects of current and projected inventories for NO_X and VOC are summarized in section IV of the proposal notice and EPA websites (*e.g., http://www.w.gov/ttn/chief.*) The relative importance of NO_X and VOC in ozone formation and control varies with local- and time-specific factors, including the relative amounts of VOC and NO_X present. In rural areas with high concentrations of VOC from biogenic sources, ozone formation and control is governed by NO_X. In some urban core situations, NO_X concentrations can be high enough relative to VOC to suppress ozone formation locally, but still contribute to increased ozone downwind from the city. In such situations, VOC reductions are most effective at reducing ozone within the urban environment and immediately downwind.

The formation of ozone increases with temperature and sunlight, which is one reason ozone levels are higher during the summer. Increased temperature increases emissions of volatile man-made and biogenic organics and can indirectly increase NO_X as well (*e.g.*, increased electricity generation for air conditioning). Summertime conditions also bring increased episodes of large-scale stagnation, which promote the build-up of direct emissions and pollutants formed through atmospheric reactions over large regions. The most recent authoritative assessments of ozone control approaches [33, 34] have concluded that, for reducing regional scale ozone transport, a NO_X control strategy would be most effective, whereas VOC reductions are most effective in more dense urbanized areas.

Studies conducted in the 1970s established that ozone occurs on a regional scale (*i.e.,* 1000s of kilometers) over much of the Eastern U.S., with elevated concentrations occurring in rural as well as metropolitan areas.[35, 36] While progress has been made in reducing ozone in many urban areas, the Eastern U.S. continues to experience elevated regional scale ozone episodes in the extended summer ozone season.

Regional 8-hour ozone levels are highest in the Northeast and Mid-Atlantic areas with peak 2002 (3-year average of the 4th highest value for all sites in the region) ranging from 0.097 to 0.099 parts per million (ppm).[37] The Midwest and Southeast States have slightly lower peak values (but still above the 8-hour standard in many urban areas) with 2002 regional averages ranging from 0.083 to 0.090 ppm. Regional-scale ozone levels in other regions of the country are generally lower, with 2002 regional averages ranging from 0.059 to 0.082 ppm. Nevertheless, some of the highest urban 8-hour ozone levels in the nation occur in southern and central California and the Houston area.

In the notice of proposed rulemaking, EPA noted that we continue to rely on the assessment of ozone transport made in great depth by the OTAG in the mid-1990s. As indicated in the NO_X SIP call proposal, the OTAG Regional and Urban Scale Modeling and Air Quality Analysis Work Groups reached the following conclusions:

A. Regional NO_X emissions reductions are effective in producing ozone benefits; the more NO_X reduced, the greater the benefit.

B. Controls for VOC are effective in reducing ozone locally and are most advantageous to urban nonattainment areas. (62 FR 60320, November 7, 1997).

The EPA proposed to reaffirm this conclusion in this rulemaking, and proposed to address only NO_X emissions for the purpose of reducing interstate ozone transport.

Some commenters suggested that in this rulemaking EPA should require regional reductions in VOC emissions as well as NO_X emissions in this rulemaking.[38] The EPA continues to believe based on the OTAG and NARSTO reports cited earlier, and the modeling completed as part of the analysis for this rule, that NO_X emissions are chiefly responsible for regional ozone transport, and that NO_X reductions will be most effective in reducing regional ozone transport. This understanding was considered an adequate basis for controlling NO_X emissions for ozone transport in the NO_X SIP call, and was upheld by the courts. As a result, EPA is requiring NO_X reductions and not VOC reductions in this rulemaking.

However, EPA agrees, that VOCs from some upwind States do indeed have an impact in nearby downwind States, particularly over short transport distances. The EPA expects that States will need to examine the extent to which VOC emissions affect ozone pollution levels across State lines, and identify areas where multi-state VOC strategies might assist in meeting the 8-hour standard, in planning for attainment. This does not alter the basis for the CAIR ozone requirements in this rule; EPA's modeling supports the conclusion that NO_X emissions from upwind states will significantly contribute to downwind nonattainment and interfere with maintenance of the 8-hour ozone standard.

2. How Did EPA Determine That Reductions in Interstate Transport, as Well as Reductions in Local Emissions, Are Warranted To Help Ozone Nonattainment Areas To Meet the 8-Hour Ozone Standard?

a. What Did EPA Say in Its Proposal Notice?

In the NPR, EPA noted that the Agency promulgated the NO_X SIP call in 1998 to address interstate ozone transport problems in the Eastern U.S. The EPA noted that it made sense to re-evaluate whether the NO_X SIP call was adequate at the same time that the Agency was assessing the need for emissions reductions to address interstate $PM_{2.5}$ problems because of overlap in the pollutants and relevant

[33] Ozone Transport Assessment Group, OTAG Final Report, 1997.

[34] NARSTO, An Assessment of Tropospheric Ozone Pollution—A North American Perspective, July 2000.

[35] National Research Council, Rethinking the Ozone Problem in Urban and Regional Air Pollution, 1991.

[36] NARSTO, An Assessment of Tropospheric Ozone Pollution—A North American Perspective, July 2000.

[37] U.S. EPA, Latest Findings on National Air Quality, August 2003.

[38] Other commenters confirmed that the control of NO_X emissions is critical for interstate ozone transport, and supported EPA's decision not to include VOC emissions in this rule.

sources, and the timetables for States to submit local attainment plans. The EPA presented a new analysis of the extent of residual 8-hour ozone attainment projected to remain in 2010, and the extent and severity of interstate pollution transport contributing to downwind nonattainment in that year.

The proposal notice said that based on a multi-part assessment, EPA had concluded that:

- ''Without adoption of additional emissions controls, a substantial number of urban areas in the central and eastern regions of the U.S. will continue to have levels of 8-hour ozone that do not meet the national air quality standards.
- * * * EPA has concluded that small contributions of pollution transport to downwind nonattainment areas should be considered significant from an air quality standpoint, because these contributions could prevent or delay downwind areas from achieving the standards.
- * * * EPA has concluded that interstate transport is a major contributor to the projected (8-hour ozone) nonattainment problem in the eastern U.S. in 2010. * * * (T)he nonattainment areas analyzed receive a transport contribution of more than 20 percent of the ambient ozone concentrations, and 21 of 47 had a transport contribution of more than 50 percent.
- Typically, two or more States contribute transported pollution to a single downwind area, so that the ''collective contribution'' is much larger than the contribution of any single State.

Also, EPA concluded that highly cost-effective reductions in NO_X emissions were available within the eastern region where it determined interstate transport was occurring, and that requiring those highly cost effective reductions would reduce ozone in downwind nonattainment areas.

In addition, the proposal examined the effect of hypothetical across-the-board emissions reductions in nonattainment areas. The notice stated that EPA had conducted a preliminary scoping analysis in which hypothetical total NO_X and VOC emissions reductions of 25 percent were applied in all projected nonattainment areas east of the continental divide in 2010, yet approximately 8 areas were projected to have ozone levels exceeding the 8-hour standard. Based on experience with state plans for meeting the one-hour ozone standard, EPA said this scenario was an indication that attaining the 8-hour standard will entail substantial cost in a number of nonattainment areas, and that further regional reductions are warranted.

b. What Did Commenters Say?

The Need for Reductions in Interstate Ozone Transport: Some commenters argued that EPA should not conduct another rulemaking to control interstate contributions to ozone because local contributions in nonattainment regions appear, according to the commenters, to have larger impacts than regional NO_X emissions. The commenters cited EPA's sensitivity modeling of hypothetical 25 percent reductions as supporting this view.

The EPA disagrees that comparing the sensitivity modeling and the CAIR control modeling is a valid way to compare the effectiveness of local and regional controls. The two scenarios do not reduce emissions by equal tonnage amounts, equal percentages of the inventory, or equal cost. These scenarios therefore do not support an assessment of the relative effectiveness of local and regional controls. While EPA in general agrees that emissions reductions in a nonattainment area will have a greater effect on ozone levels in that area than similar reductions a long distance away, EPA does not agree that the modeling supports the conclusion that all additional controls to promote attainment with the 8-hour standard should be local. The level of reduction assumed was a hypothetical level, not a level determined to be reasonable cost nor a mandated level of reduction. The commenters provided no evidence that reasonable local controls alone would result in attainment throughout the East. However, EPA did receive comments that such a level would result in costly controls and might not be feasible in some areas that have previously imposed substantial controls.

The EPA believes it is clear that further reductions in emissions contributing to interstate ozone transport, beyond those required by the NO_X SIP Call, are warranted to promote attainment of the 8-hour ozone standard in the eastern U.S. As explained elsewhere in this final rule, EPA analyzed interstate transport remaining after the NO_X SIP Call, and determined—considering both the impact of interstate transport on downwind nonattainment, and the potential for highly cost effective reductions in upwind States—that 25 States significantly contribute to 8-hour ozone nonattainment downwind. The importance of transport is illustrated, as mentioned above, by EPA's findings for the final rule that (1) all the 2010 nonattainment counties analyzed were projected to receive a transport contribution of 24 percent or more of the ambient ozone concentrations, and (2) that 16 of 38 counties are projected to have a transport contribution of more than 50 percent.

In addition, EPA received multiple comments from State associations and individual States strongly agreeing that further reductions in interstate ozone transport are warranted to promote attainment with the 8-hour standard, to protect public health, and to address equity concerns of downwind states affected by transport. For example, comments from the Maryland Department of the Environment stated, ''Our 15 year partnership with researchers from the University of Maryland has produced data that shows on many summer days the ozone levels floating into Maryland area are already at 80 to 90 percent of the 1-hour ozone standard and actually exceed the new 8-hour ozone standard before any Maryland emissions are added. * * * Serious help is needed from EPA and neighboring states to solve Maryland's air pollution problems. * * * Local reductions alone will not clean up Maryland's air.'' The comments of the Ozone Transport Commission stated that even after levels of control envisioned by EPA in 2010 (under the Clear Skies Act), interstate transport from other states would continue to affect the Ozone Transport Region created by the CAA (Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia). ''Our modeling demonstrates that even in the extreme example of zero anthropogenic emissions within the OTR (Ozone Transport Region), 145 of 146 monitors show a significant (>25%) increment of the 8-hour standard taken up by transport from outside the OTR.'' Comments from the North Carolina Department of Environment and Natural Resources stated, ''The reductions proposed in [EPA's rule] in the other states are needed to ensure that North Carolina can attain and maintain the health-based air quality standards for * * * 8-hour ozone.''

Magnitude of Ozone Reductions Achieved: Commenters stated that NO_X reductions should not be pursued because the 8-hour ozone reductions in projected nonattainment counties resulting from the required NO_X reductions are too small—1–2 ppb in only certain areas. According to commenters, these benefits are smaller than the threshold for determining significant contribution.

The EPA disagrees with the notion that if air quality improvements would be limited, then nothing further should be done to address interstate transport. Based on the difference between the base case and CAIR control case modeling results, EPA has concluded that interstate air quality impacts are significant from an air quality standpoint, and that highly cost effective reductions are available to reduce ozone transport. State comments have corroborated EPA's conclusion that a number of areas will face high local control costs, or even be unable to attain the 8-hour ozone standard, without further reductions in interstate transport. Therefore, EPA believes it is important for upwind states to modify their SIPs so that they contain adequate provisions to prohibit significant contributions to downwind nonattainment or interference with maintenance as the statute requires. The EPA has established an amount of required emissions reductions based on controls that are highly cost effective. The resulting improvements in downwind ozone levels are needed for attainment, public health and equity reasons.

The 2 ppb significance threshold that commenters cite is part of the test that EPA used to identify which States should be evaluated for inclusion in a rule requiring them to reduce emissions to reduce interstate transport. (See section VI.) This 2 ppb threshold is based on the impact on a downwind area of eliminating *all* emissions in an upwind State. The ozone reductions from CAIR will improve public health and will decrease the extent and cost of local controls needed for attainment in some areas. In addition, base case modeling for this rule shows that of the 40 counties projected in nonattainment in 2010, 16 counties are within 2 ppb of the standard, 6 counties are within 3 ppb, and 3 counties are within 4 ppb. In 2015, projected base case ozone concentrations in over 70 percent of nonattaining counties (*i.e.*, 16 of 22 counties) are within 5 ppb of the standard.

Reducing NO_X emissions has multiple health and environmental benefits. Controlling NO_X reduces interstate transport of fine particle levels as well as ozone levels, as discussed elsewhere in this notice. Although EPA is not relying on other benefits for purposes for setting requirements in this rule, reducing NO_X emissions also helps to reduce unhealthy ozone and PM levels within a State, as well as reduce acid deposition to soils and surface waters, eutrophication of surface and coastal waters, visibility degradation, and impacts on terrestrial and wetland systems such as changes in species composition and diversity.

EPA's Authority To Require Controls Beyond the NO_X SIP Call: Commenters emphasized that in the NO_X *SIP Call, EPA determined the States whose emissions contribute significantly to nonattainment, EPA mandated NO_X* emissions reductions that would eliminate those significant contributions, and EPA indicated that it would reconsider the matter in 2007. This commenter argued that for the States included in the NO_X SIP Call, EPA may not, as a legal matter, conduct further rulemaking at this time because the affected States are no longer contributing significantly to nonattainment downwind. In any event, the commenters said, EPA should abide by its statement that it would revisit the matter in 2007, and EPA should not do so earlier.

Sound policy considerations support re-examining interstate ozone transport at this time. At the time of the NO_X SIP Call, EPA anticipated reassessing in 2007 the need for additional reductions in emissions that contribute to interstate transport, but EPA has accelerated that date in light of various circumstances, including the fact that we are undertaking similar action with the $PM_{2.5}$ NAAQS. In addition, in light of overlap in the pollutants, States, and sources likely to be affected, it is prudent to coordinate action under the 8-hour ozone standard. The EPA notes that evaluating $PM_{2.5}$ transport and ozone transport together at this time will enable States to consider the resulting rules in devising their $PM_{2.5}$ and 8-hour ozone attainment plans, and will enable States and sources to plan emissions reductions knowing their transport-related reduction requirements for both standards.

CAA section 110(a)(2)(D) requires that State SIPs contain ''adequate provisions'' prohibiting emissions that significantly contribute to nonattainment areas in, or interfere with maintenance by, other States. Over time, emissions of ozone precursors, the (projected) non-attainment status of receptors, the modeling tools that EPA and the states use to conduct their analyses, the data available to the states or EPA and other analytic tools or conditions may change. The EPA has conducted an updated analysis of upwind contribution to downwind nonattainment of 8-hour ozone nonattainment areas after the NO_X SIP Call, including updated emissions projections, updated air quality modeling, and updated analysis of control costs. This has revealed a need for reductions beyond those required by the NO_X SIP Call in order for upwind states to be in compliance with section 110(a)(2)(D). The EPA thus disagrees with commenters' assertions that the provisions of section 110(a)(2)(D) prevent EPA from conducting further evaluation of upwind contributions to downwind nonattainment at this time. The EPA also notes that the NO_X SIP Call, a 1998 rulemaking, promulgated a set of requirements intended to eliminate significant contribution to downwind ozone nonattainment at the time of implementation, which EPA identified on the basis of modeling for the year 2007 (although implementation was required to occur several years earlier). In today's action, EPA is reviewing the transport component of 8-hour ozone nonattainment for the period beginning in 2010, consistent with the criteria in the NO_X SIP Call as applied to present circumstances, concluding that even with implementation of the NO_X SIP Call controls, upwind States will contribute significantly to downwind ozone nonattainment and interfere with maintenance at a point after 2007. No provision of the CAA prohibits this action.

Commenters added that the purpose of the CAIR rulemaking seemed to be to account for the fact that control costs have changed since the date of the NO_X SIP Call. The commenters said that control costs will frequently fluctuate, but that such fluctuations should not merit revised rulemaking.

In response, we would note that EPA conducted an updated analysis for air quality impacts, not only costs, in determining that further reductions in interstate ozone transport are warranted. That air quality analysis showed a substantial, continuing interstate transport problem for areas after implementation of the NO_X SIP Call. The EPA does have the legal authority to reconsider the scope of the area that significantly contributes and the level of control determined to be ''highly cost-effective'' based on new information. Updated information shows that lower NO_X burners and SCR achieve better performance than previously estimated and as a result are more cost effective than previously anticipated. This rule follows the NO_X SIP Call by six years; EPA does not believe that this represents a too-frequent re-evaluation, particularly given the stay of the 8-hour basis for the NO_X SIP Call (*See, e.g.,* CAA section 109(d)(1) requiring EPA to reevaluate the NAAQS themselves every five years.) So both updated air quality and cost information supports further

NO_X controls to reduce interstate transport.

Some commenters argued that EPA should delay imposing control obligations on upwind States for the 8-hour ozone NAAQS until after EPA has implemented local control requirements, and after all of the NO_X SIP Call control requirements are implemented and evaluated. Others said EPA should not impose requirements on non-SIP-Call States until after all 8-hour controls—NO_X SIP Call and local—are implemented.

We agree that the NO_X SIP Call should be taken into account in evaluating the need for further interstate transport controls. We have taken the NO_X SIP Call into account by including the effect of the NO_X SIP Call in the base case used for the CAIR analysis, and by conducting analyses to confirm that CAIR will achieve greater ozone-season reductions than the SIP Call. The EPA disagrees that the Agency should wait for implementation of local controls before determining transport controls. There is no legal requirement that EPA wait to determine transport controls until after local controls are implemented. The EPA's basis for this legal interpretation is explained in section II.A. above. In addition, the Agency believes it is important to address interstate transport expeditiously for public health.

C. Comments on Excluding Future Case Measures From the Emissions Baselines Used To Estimate Downwind Ambient Contribution

The EPA received comments that the 2010 analytical baseline for evaluating whether upwind emissions meet the air quality portion of the ''contribute significantly'' standard should reflect local control measures that will be required in the downwind nonattainment areas, or broader statewide measures in downwind states, to attain the $PM_{2.5}$ or 8-hour ozone NAAQS by the relevant attainment dates, many of which are (or are anticipated to be) 2010 or earlier. This single target year was chosen both to address analytical tool constraints and to reasonably reflect future conditions in or near the initial attainment years for both ozone and PM nonattainment areas. The EPA did include in the baseline most of the specifically required measures that can be identified at this time, but did not include any further measures that would be needed for satisfying ''rate of progress'' requirements or for attainment of the $PM_{2.5}$ and 8-hour ozone standards. If EPA had included further local controls, the commenters contend, fewer upwind States would have exceeded our significant contribution thresholds.

We reject any notion that in determining the need for transport controls in upwind states, EPA should assume that the affected downwind areas must ''go all the way first''—that is, assume that downwind areas put on local in-state controls sufficient to reach attainment, or assume that downwind states with nonattainment areas implement statewide control measures. The EPA does not believe these are appropriate assumptions. The former assumption would eviscerate the meaning of CAA section 110(a)(2)(D). The latter assumption would make the downwind state solely responsible for reductions in any case where a downwind state could attain through in-state controls alone, even if the upwind state contribution was significantly contributing to nonattainment problems in the downwind state. We do not believe that this approach would be consistent with the intent of section 110(a)(2)(D), which in part is to hold upwind states responsible for an appropriate share of downwind nonattainment and maintenance problems, and to prevent scenarios in which downwind states must impose costly extra controls to compensate for significant pollution contributions from uncontrolled or poorly controlled sources in upwind states. In addition, this approach could raise costs of meeting air quality standards because highly cost effective controls in upwind States would be foregone.

Rather, in the particular circumstances presented here, we think the adoption of regional controls at this time under section 110(a)(2)(D) is consistent with sound policy and section 110. Based on our analysis, the states covered by CAIR make a significant contribution to downwind nonattainment and the required reductions are highly cost effective. The reductions will reduce regional pollution problems affecting multiple downwind areas, will make it possible for States to determine the extent of local control needed knowing the reductions in interstate pollution that are required, will address interstate equity issues that can hamper control efforts in downwind States, and reflect considerations discussed in detail in section VII.

Although some commenters advocated specifically including statutorily mandated future nonattainment area controls in the analytical baseline, it would be difficult as a practical matter to predict the extent of local controls that will be required (beyond controls previously required) in each area in advance of final implementation rules interpreting the Act's requirements for $PM_{2.5}$ and 8-hour ozone, and before the state implementation plan process. Subpart 2 provisions that apply to certain ozone nonattainment areas are quite specific regarding some mandatory measures; we believe the CAIR baseline for the most part captures these measures. (See Response to Comments document in the docket.) As noted above, the choice of a single analytical year of 2010 was made to reflect baseline conditions at a date at or near the attainment dates for different pollutants and classes of areas. Because the attainment date for many ozone areas is 2009 or earlier, it should be noted that the analyses in 2010 may slightly overestimate the benefits of a number of national rules for mobile sources that grow with time. As noted elsewhere, these differences are unlikely to be significant.

D. What Criteria Should Be Used To Determine Which States Are Subject to This Rule Because They Contribute to $PM_{2.5}$ Nonattainment?

1. What Is the Appropriate Metric for Assessing Downwind $PM_{2.5}$ Contribution?

a. Notice of Proposed Rulemaking

In the NPR, we proposed as the metric for identifying a State as significantly contributing (depending upon further consideration of costs) to downwind nonattainment, the predicted change, due to the upwind State's emissions, in $PM_{2.5}$ concentration in the downwind nonattainment area that receives the largest ambient impact. The EPA proposed this metric in the form of a range of alternatives for a ''bright line,'' that is, ambient impacts at or greater than the chosen threshold level indicated that the upwind State's emissions do contribute significantly (depending on cost considerations), and that ambient impacts below the threshold mean that the upwind State's emissions do not contribute significantly to nonattainment. As detailed in section VI below, EPA conducted the analysis through air quality modeling that removed the upwind State's anthropogenic SO_2 and NO_X emissions, and determined the difference in downwind ambient $PM_{2.5}$ levels before and after removal. The modeling results indicate a wide range of maximum downwind nonattainment impacts from the 37 States that we evaluated. The largest maximum contribution is 1.67 micrograms per cubic meter ($\mu g/m^3$), from Ohio to both Allegheny and Beaver counties in Pennsylvania.

b. Comments and EPA's Responses

The EPA proposed to use the maximum contribution on any downwind nonattainment area for assessing downwind $PM_{2.5}$ contributions. Many commenters expressed agreement with our proposed metric, however, many others disagreed. One group of these commenters indicated that EPA should distinguish the relative contribution from States using two parameters: (1) How many downwind nonattainment receptors they contribute to, and (2) how much they contribute to each such receptor. The commenters indicated that this approach would avoid inequities created by the disproportionate impact of some upwind contributors on their downwind neighbors. The EPA interprets these comments to suggest a metric that collectively includes both of these parameters, such as the sum of all downwind impacts on all affected receptors. This metric would result in higher values for States contributing to multiple receptors and at relatively high levels, and lower values for States contributing to fewer receptors and at relatively low levels.

The EPA's proposed metric does address how much each State contributes to a downwind neighbor; however, EPA does not believe that multiple downwind receptors need to be impacted in order for a particular state to be required to make emissions reductions under CAA section 110(a)(2)(D). Under this provision, an upwind State must include in the SIP adequate provisions that prohibit that State's emissions that ''contribute significantly to nonattainment in * * * *any other State* * * *.'' (Emphasis added.) Our interpretation of this provision is that the emphasized terms make clear that the upwind State's emissions must be controlled as long as they contribute significantly to a single nonattainment area.

One commenter agreed with EPA's use of maximum annual average downwind contribution, but suggested that EPA consider additional metrics such as: (a) Contributions to adverse health and welfare effects from short-term $PM_{2.5}$ concentrations; (b) contributions to worst 20 percent haze levels in Class 1 areas; and (c) contributions to adverse effects of sulfur and nitrogen deposition to acid sensitive surface waters and forest soils. The EPA appreciates that these metrics all have merit in their focus on the health and environmental consequences of emissions, however, in determining a metric for significant contributions, we must focus on implementation of CAA section 110(a)(2)(D) provisions regarding significant contribution to nonattainment of the $PM_{2.5}$ NAAQS.

Another commenter suggested EPA use the maximum annual average impact, as we proposed, but add the maximum daily $PM_{2.5}$ contribution. The commenter notes that this additional metric would indicate whether specific meteorological events drive the concentration change or whether there is a consistent pattern of transport from one area to another. It is not clear to EPA how the single data point of the maximum daily contribution indicates a consistent pattern of transport from one area to another since it is a measure from only a single day. Further, EPA does not agree that multiple days of impact is a relevant criterion for evaluating whether a State contributes significantly to nonattainment, since in theory, a single high-contribution event could be the cause or a substantial element of nonattainment of the annual average $PM_{2.5}$ standard. Because we currently do not observe nonattainment of the daily average $PM_{2.5}$ standard in Eastern areas, nonattainment of the annual average $PM_{2.5}$ standard is the relevant evaluative measure.

Some commenters suggested separately evaluating the NO_X- and SO_2-related impacts (*i.e.*, particulate nitrate and particulate sulfate) on nonattainment. As discussed in section II of this notice, EPA's approach to evaluating a State's impact on downwind nonattainment by considering the entirety of the State's SO_2 and NO_X emissions is consistent with the chemical interactions in the atmosphere of SO_2 and NO_X in forming $PM_{2.5}$. The contributions of SO_2 and NO_X emissions are generally not additive, but rather are interrelated due to complex chemical reactions.

c. Today's Action

The EPA continues to believe that for each upwind State analyzed, the change in the annual $PM_{2.5}$ concentration level in the downwind nonattainment area that receives the largest impact is a reasonable metric for determining whether a State passes the ''air quality'' portion of the ''contribute significantly'' test, and therefore that State should be considered further for emissions reductions (depending upon the cost of achieving those reductions). This single concentration-based metric is adequate to capture the impact of SO_2 and NO_X emissions on downwind annual $PM_{2.5}$ concentrations.

2. What Is the Level of the $PM_{2.5}$ Contribution Threshold?

a. Notice of Proposed Rulemaking

In the NPR, EPA proposed to establish a State-level annual average $PM_{2.5}$ contribution threshold from anthropogenic SO_2 and NO_X emissions that was a small percentage of the annual air quality standard of 15.0 μg/m^3. The EPA based this proposal on the general concept that an upwind State's contribution of a relatively low level of ambient impact should be regarded as significant (depending on the further assessment of the control costs). We based our reasoning on several factors. The EPA's modeling indicates that at least some nonattainment areas will find it difficult or impossible to attain the standards without reductions in upwind emissions. In addition, our analysis of ''base case'' $PM_{2.5}$ transport shows that, in general, $PM_{2.5}$ nonattainment problems result from the combined impact of relatively small contributions from many upwind States, along with contributions from in-State sources and, in some cases, substantially larger contributions from a subset of particular upwind States. In the NO_X SIP Call rulemaking, we termed this pattern of contribution—which is also present for ozone nonattainment—''collective contribution.''

In the case of $PM_{2.5}$, we have found collective contribution to be a pronounced feature of the $PM_{2.5}$ transport problem, in part because the annual nature of the $PM_{2.5}$ NAAQS means that throughout the entire year and across a range of wind patterns—rather than during just one season of the year or on only the few worst days during the year which may share a prevailing wind direction—emissions from many upwind States affect the downwind nonattainment area.

As a result, to address the transport affecting a given nonattainment area, many upwind States must reduce their emissions, even though their individual contributions may be relatively small. Moreover, as noted above, EPA's air quality modeling indicates that at least some nonattainment areas will find it difficult or impossible to attain the standards without reductions in upwind emissions. In combination, these factors suggest a relatively low value for the $PM_{2.5}$ transport contribution threshold is appropriate. For reasons specified in the NPR (69 FR 4584), EPA initially proposed a value of 0.15 μg/m^3 (1% of the annual standard) for the significance criterion, but also presented analyses based on an alternative of 0.10 μg/m^3 and called for comment on this alternative as well as on ''the use of higher or lower thresholds for this purpose'' (69 FR 4584).

The EPA adopted a conceptually similar approach to that outlined above for determining that the significance level for ozone transport in the NO_X SIP Call rulemaking should be a small number relative to the NAAQS. The DC Circuit Court, in generally upholding the NO_X SIP Call, viewed this approach as reasonable. *Michigan* v. *EPA,* 213 F.3d 663, 674–80 (DC Cir. 2000), *cert. denied,* 532 U.S. 904 (2001). After describing EPA's overall approach of establishing a significance level and requiring States with impacts above the threshold to implement highly cost-effective reductions, the Court explained: ''EPA's design was to have a lot of States make what it considered modest NO_X reductions * * *. '' *Id.* at 675. Indeed, the Court intimated that EPA could have established an even lower threshold for States to pass the air quality component:

> The EPA has determined that ozone has some adverse health effects—however slight—at every level [citing National Ambient Air Quality Standards for Ozone, 62 FR 38856 (1997)]. Without consideration of cost it is hard to see why any ozone-creating emissions should not be regarded as fatally ''significant'' under section 110(a)(2)(D)(i)(I).''

213 F.3d at 678 (emphasis in original).

We believe the same approach applies in the case of $PM_{2.5}$ transport.

b. Comments and EPA's Responses

Many commenters indicated that EPA did not adequately justify the proposed annual average $PM_{2.5}$ contribution threshold level of 0.15 μg/m³. Some commenters favor the alternative 0.10 μg/m³ proposed by EPA, citing their agreement with EPA's rationale for 0.10 μg/m³ while criticizing as arbitrary EPA's rationale for 0.15 μg/m³.

Some commenters argued that the public health impact portion of EPA's rationale for establishing a relatively low-level threshold was not relevant. The commenters said that EPA previously determined, in establishing the $PM_{2.5}$ NAAQS, that ambient levels at or above 15.0 μg/m³ were of concern for protecting public health, not the much lower levels that EPA proposed as the thresholds. In the NPR, we stated that we considered that there are significant public health impacts associated with ambient $PM_{2.5}$, even at relatively low levels. In generally upholding the NO_X SIP Call, the DC Circuit noted a similar reason for establishing a relatively low threshold for ozone impacts. *Michigan* v. *EPA,* 213 F.3d 663, 678 (DC Cir. 2000), cert. denied, 532 U.S. 904 (2001). The EPA notes that by using a metric that focuses on the contribution of upwind areas to downwind areas that are above 15.0 μg/m³, relatively low contributions to levels above the annual $PM_{2.5}$ standard are highly relevant to public health protection.

Many commenters offered alternative thresholds higher than 0.15 μg/m³, citing previous EPA rules or policies as justification for the alternative level. Some suggested the $PM_{2.5}$ threshold should be equivalent in percentage terms to the threshold employed for assessing maximum downwind 8-hour ozone contributions. The threshold for maximum downwind 8-hour ozone concentration impact used in the NO_X SIP Call, and proposed for use in the CAIR, is 2 parts per billion (ppb), or about 2.5 percent of the standard level of 80 ppb. Applying the 2.5 percent criterion to the 15.0 μg/m³ annual $PM_{2.5}$ standard would yield a significance threshold of 0.35 μg/m³.

The EPA disagrees with the comment that the thresholds for annual $PM_{2.5}$ and 8-hour ozone should be an equivalent percentage of their respective NAAQS. Both the forms and averaging times of the two standards are substantially different, with 8-hour ozone based on the average of the 4th highest daily 8-hour maximum values from each of 3 years, and $PM_{2.5}$ based on the average of annual means from 3 successive years. These fundamental differences in time scales, and thus in the patterns of transport that are relevant to contributing to nonattainment, do not suggest a transparent reason for presuming that the contribution thresholds should be equivalent. As discussed above, when more States make smaller individual contributions because of the annual nature of the $PM_{2.5}$ standard, it makes sense to have a threshold for $PM_{2.5}$ that is a smaller percentage of its NAAQS.

Other commenters suggested that in setting the maximum downwind $PM_{2.5}$ threshold, EPA should take into consideration the measurement precision of existing $PM_{2.5}$ monitors. The commenters assert that such measurement carries ''noise'' in the range of 0.5—0.6 μg/m³. Because many daily average monitor readings are averaged to calculate the annual average, the precision of the annual average concentration is better than the figures cited by the commenters. Indeed, the annual standard is expressed as 15.0 μg/m³, rounded to the nearest ¹⁄₁₀ μg, because such small differences are meaningful on an annual basis. While disagreeing with the specific amounts suggested by commenters, EPA recognizes that the $PM_{2.5}$ threshold specified in the proposal contains two digits beyond the decimal place, while the NAAQS specifies only one. The EPA agrees that specification of a threshold value of 0.15 μg/m³ does suggest an overly precise test that might need to take into account modeled difference in $PM_{2.5}$ values as low as 0.001 μg/m³.

Other commenters indicated that modeling ''noise''—that is, imprecision—is a relevant consideration for establishing a threshold whose evaluation depends on air quality modeling analysis. These commenters indicated that a threshold of 5 percent of the NAAQS (*i.e.,* 0.75 μg/m³) is more reasonable considering modeling sensitivity. The commenters were not clear about what they mean by modeling ''noise'' and did not explain how it relates to the use of a threshold metric in the context of the CAIR.

In responding to the comment, we have considered some possible contributors to what the commenter describes as ''noise.'' There is the possibility that the air quality model has a systematic bias in predicting concentrations resulting from a given set of emissions sources. The EPA uses the model outputs in a relative, rather than an absolute, sense so that any modeling bias is constrained by real world results. As described further in section VI, EPA conducts a relative comparison of the results of a base case and a control case to estimate the percentage change in ambient $PM_{2.5}$ from the current year base case, holding meteorology, other source emissions, and other factors contributing to uncertainty constant. With this technique, any absolute modeling bias is cancelled out because the same model limitations and uncertainties are present in each set of runs.

Another possible source of noise is in the relative comparison of two model runs conducted on different computers. Since the computers used by EPA to run air quality models do not have any significant variability in their numerical processes, two model runs with identical inputs result in outputs that are identical to many significant digits. On the other hand, EPA believes it is not appropriate or necessary to carry such results to a level of precision that is beyond that required by the $PM_{2.5}$ NAAQS itself [39].

Many commenters noted that EPA's proposed threshold of 0.15 μg/m³, or one percent of the annual $PM_{2.5}$ NAAQS of 15.0 μg/m³, is lower than the single-source contribution thresholds

[39] In attainment modeling for the annual $PM_{2.5}$ NAAQS, results are carried to the second place beyond the decimal, in contrast to the three places beyond decimal noted above for the proposed threshold.

employed for PM_{10} in certain other regulatory contexts. Commenters cited several different thresholds, including thresholds governing the applicability of the preconstruction review permit program and the emissions reduction requirement for certain major new or modified stationary sources located in attainment or unclassified areas;[40] and thresholds in the PSD rules that may relieve proposed sources from performing comprehensive ambient air quality analyses.[41]

Since the thresholds referred to by the commenters serve different purposes than the CAIR threshold for significant contribution, it does not follow that they should be made equivalent. The implication of the thresholds cited by the commenters is not that single-source contributions below these levels indicate the absence of a contribution. Rather, these thresholds address whether further more comprehensive, multi-source review or analysis of appropriate control technology and emissions offsets are required of the source. A source with estimated impacts below these levels is recognized as still affecting the airshed and is subject to meeting applicable control requirements, including best available control technology, designed to moderate the source's impact on air quality. The purpose of the CAIR threshold for $PM_{2.5}$ is to determine whether the annual average contribution from a collection of sources in a State is small enough not to warrant any additional control for the purpose of mitigating interstate transport, even if that control were highly cost effective.

One commenter suggested that EPA also establish and evaluate a threshold for a potential new tighter 24-hour $PM_{2.5}$ standard (*e.g.*, 1 percent of 30 μg/m³). The EPA must base its criteria on evaluation of the current $PM_{2.5}$ standards and not standards that may be considered in the future.

c. Today's Action

The EPA continues to believe that the threshold for evaluating the air quality component of determining whether an individual State's emissions ''contribute significantly'' to downwind nonattainment of the annual $PM_{2.5}$ standard, under CAA section 110(a)(2)(D) should be very small compared to the NAAQS. We are, however, persuaded by commenters arguments on monitoring and modeling that the precision of the threshold should not exceed that of the NAAQS. Rounding the proposal value of 0.15, the nearest single digit corresponding to about 1% of the $PM_{2.5}$ annual NAAQS is 0.2 μg/m³. The final rule is based on this threshold. The EPA has decided to apply this threshold such that any model result that is below this value (0.19 or less)indicates a lack of significant contribution, while values of 0.20 or higher exceed the threshold.[42]

Using this metric for determining whether a State ''contributes significantly'' (before considering cost) to $PM_{2.5}$ nonattainment, our updated modeling shows that Kansas, Massachusetts, New Jersey, Delaware, and Arkansas (all included in the original proposal) no longer exceed the 0.2 μg/m³ annual average $PM_{2.5}$ contribution threshold. Of these states, only Arkansas would exceed the threshold of 0.15 μg/m³ that was included in the proposal.

E. What Criteria Should Be Used To Determine Which States Are Subject to This Rule Because They Contribute to Ozone Nonattainment?

1. Notice of Proposed Rulemaking

In assessing the contribution of upwind States to downwind 8-hour ozone nonattainment, EPA proposed to follow the approach used in the NO_X SIP Call and to employ the same contribution metrics, but with an updated model and updated inputs that reflect current requirements (including the NO_X SIP Call itself).[43]

The air quality modeling approach we proposed to quantify the impact of upwind emissions includes two different methodologies: Zero-out and source apportionment. As described in section VI, EPA applied each methodology to estimate the impact of all of the upwind State's NO_X emissions on each downwind nonattainment areas.

The EPA's first step in evaluating the results of these methodologies was to remove from consideration those States whose upwind contributions were very low. Specifically, EPA considered an upwind State not to contribute significantly to a downwind nonattainment area if the State's maximum contribution to the area was either (1) less than 2 ppb, as indicated by either of the two modeling techniques; or (2) less than one percent of total nonattainment in the downwind area.[44]

If the upwind State's impact exceeded these thresholds, then EPA conducted a further evaluation to determine if the impact was high enough to meet the air quality portion of the ''contribute significantly'' standard. In doing so, EPA organized the outputs of the two modeling techniques into a set of ''metrics.'' The metrics reflect three key contribution factors:

- The magnitude of the contribution (actual amount of ozone contributed by emissions in the upwind State to nonattainment in the downwind area);
- The frequency of the contribution (how often contributions above certain thresholds occur); and
- The relative amount of the contribution (the total ozone contributed by the upwind State compared to the total amount of nonattainment ozone in the downwind area).

The specific metrics on which EPA proposed to rely are the same as those used in the NO_X SIP Call. Table III–1 lists them for each of the two modeling techniques, and identifies their relationship to the three key contribution factors.

[40] *See* 40 CFR 51.165(b)(2). New or modified major sources in attainment or unclassifiable areas must undergo preconstruction permit review, adopt best available control technology, and obtain emissions offsets if they are determined to ''cause or contribute'' to a violation of the NAAQS. ''Cause or contribute'' is defined as an impact that exceeds 5 μg/m³ (3.3 percent) of the 150 μg/m³ 24-hour average PM_{10} NAAQS , or 1 μg/m³ (2 percent) of the annual average PM_{10} NAAQS.

[41] *See* 40 CFR 51.166(i)(5)(i). Proposed new sources or existing-source modifications that would contribute less than 10 μg/m³ (or 5.3%) of the 150 μg/m³ PM_{10} 24-hour average NAAQS, estimated using on a screening model, may avoid the requirement of collecting and submitting ambient air quality data.

[42] This truncation convention for $PM_{2.5}$ is similar to that used in evaluating modeling results in applying the ozone significance screening criterion of 2 ppb in the NO_X SIP call and the CAIR proposal (Technical Support Document for the Interstate Air Quality Rule Air Quality Modeling Analyses'', January 2004. Docket # OAR–2003–0053–0162), as well as today's final action.

[43] Today's action, including the updated modeling, fulfills EPA's commitment in the NO_X SIP Call (which EPA finalized in 1998) to reevaluate interstate ozone contributions by 2007. *See* 63 FR 57399; October 27, 1998.

[44] See the CAIR Air Quality Modeling TSD for description of the methodology used to calculate these metrics.

TABLE III–1.—OZONE CONTRIBUTION FACTORS AND METRICS

Factor	Modeling technique	
	Zero-out	Source apportionment
Magnitude of Contribution	Maximum contribution	Maximum contribution; and Highest daily average contribution (ppb and percent).
Frequency of Contribution	Number and percent of exceedances with contributions in various concentration ranges.	Number and percent of exceedances with contributions in various concentration ranges.
Relative Amount of Contribution	Total contribution relative to the total exceedance ozone in the downwind area; and. Population-weighted total contribution relative to the total population-weighted exceedance ozone in the downwind area.	Total average contribution to exceedance hours in the downwind area.

In the NPR, EPA proposed threshold values for the metrics. An upwind State whose contribution to a downwind area exceeded the threshold values for at least one metric in each of at least two of the three sets of metrics was considered to contribute significantly (before considering cost) to that downwind area. To reiterate, the three sets of metrics reflect the factors of magnitude of contribution, frequency of contribution, and relative percentage on nonattainment.

In fact, EPA noted in the NPR that for each upwind State, the modeling disclosed at least one linkage with a downwind nonattainment area in which all factors (magnitude, frequency, and relative amount) were found to indicate large and frequent contributions. In addition, EPA noted in the NPR that each upwind State contributed to nonattainment problems in at least two downwind States (except for Louisiana and Arkansas which contributed to nonattainment in only 1 downwind State).

In addition, EPA noted in the NPR that for most of the individual linkages, the factors yield a consistent result across all three sets of metrics (*i.e.*, either (i) large and frequent contributions and high relative contributions or (ii) small and infrequent contributions and low relative contributions). In some linkages, however, not all of the factors are consistent. The EPA believes that each of the factors provides an independent, legitimate measure of contribution.

In the NPR, EPA applied the evaluation methodology described above to each upwind-downwind linkage to determine which States contribute significantly (before considering cost) to nonattainment in the 40 downwind counties in nonattainment for ozone in the East. The analysis of the metrics for each linkage was presented in the AQMTSD for the NPR. The modeling analysis supporting the final rule is an update to the NPR modeling, and is described in more detail in section VI below.

2. Comments and EPA Responses

Some commenters submitted comments specifically on the 8-hour ozone metrics. One commenter asserted that in calculating the ''Relative Amount of Contribution'' metric, EPA treats the modeled reductions from zeroing out a State's emissions as impacting only the portion of the downwind receptor's ambient ozone level that exceeds the 8-hour average 84 ppb level. The commenter asserted that this approach falsely treats the upwind state's emissions as contributing to the amount of ozone that exceeds the NAAQS, and thus inflates the ambient impact of those emissions. The commenter concluded that it would be more appropriate to treat the upwind emissions as impacting all of the downwind ozone level (not just the portion greater than 84 ppb). We interpret this comment to mean that in expressing an upwind State's contribution as a percentage, the denominator of the percentage should be the downwind area's total ozone contribution, rather than the downwind area's ozone excess above the NAAQS, but that the same threshold should be used to evaluate contribution. This would tend to result in fewer upwind States being found to be significant with respect to this metric.

We believe that it is important to examine the ozone contribution relative to the amount of ozone above the NAAQS as well as the amount relative to total nonattainment ozone. Both approaches have merit. The intent of the relative contribution metric, as calculated for the zero-out modeling, is to view the contribution of the upwind State relative to the amount that the downwind area is in nonattainment; that is, the amount of ozone above the NAAQS. However, our relative amount metric for the source apportionment modeling does treat the amount of contribution relative to the total amount of ozone when ozone concentrations are predicted to be above the NAAQS. To be found a significant contributor, an upwind State must be above the threshold for both the zero-out-based metric and the source-apportionment-based metric. Thus, our approach to considering the significance of interstate ozone transport captures both approaches for examining the relative amount of contribution and does not favor one approach over the other, as discussed above.

3. Today's Action

The EPA is finalizing the methodology proposed in the NPR, and discussed above, for evaluating the air quality portion of the ''contribute significantly'' standard for ozone.

F. Issues Related to Timing of the CAIR Controls

1. Overview

A number of commenters questioned the need for CAIR requirements considering that cap dates of 2010 and 2015 are later than the attainment dates that, in the absence of extensions, would apply to certain downwind $PM_{2.5}$ areas and ozone nonattainment areas. Other commenters, noting that states will be required to adopt controls in local attainment plans, questioned whether CAIR controls would still be needed to avoid significant contribution to downwind nonattainment, or whether the controls would still be needed to the extent required by the rule.

Of course, CAIR will achieve substantial reductions in time to help many nonattainment areas attain the standards by the applicable attainment dates. The design of the SO_2 program, including the declining caps in 2010 and 2015 and the banking provisions, will steadily reduce SO_2 emissions over time, achieving reductions in advance of the cap dates; and the 2009 and 2015 NO_X reductions will be timely for many downwind nonattainment areas.

Although many of today's nonattainment areas will attain before all the reductions required by CAIR will be achieved, it is clear that CAIR's reductions will still be needed through 2015 and beyond. The EPA's air quality modeling has demonstrated that upwind States have a sufficiently large impact on downwind areas to require reductions in 2010 and 2015 under CAA section 110(a)(2)(D). Under this provision, SIPs must prohibit emissions from sources in amounts that ''will contribute significantly to * * * nonattainment'' or ''will interfere with maintenance''.[45] The EPA has evaluated the attainment status of the downwind receptors in 2010 and 2015, and has determined that each upwind State's 2010 and 2015 emissions reductions are necessary to the extent required by the rule because a downwind receptor linked to that upwind State will either (i) remain in nonattainment and continue to experience significant contribution to nonattainment from the upwind State's emissions; or (ii) attain the relevant NAAQS but later revert to nonattainment due, for example, to continued growth of the emissions inventory.

The argument that the CAIR reductions are justified, in part, by the need to prevent interference with maintenance, is a limited one. The EPA does not believe that the ''interfere with maintenance'' language in section 110(a)(2)(D) requires an upwind state to eliminate all emissions that may have some impact on an area in a downwind state that is (or once was) in nonattainment and that, therefore, will need (or now needs) to maintain its attainment status. Instead, we believe that CAIR emission reductions are needed beyond 2010 and 2015, in part, to prevent upwind states from significantly interfering with maintenance in other states because our analysis shows it is likely that, in the absence of the CAIR, a current or projected attainment area will revert to nonattainment due to continued emissions growth or other relevant factors. We are not taking the position that CAIR controls are automatically justified to prevent interference with maintenance in every area initially modeled to be in nonattainment.

We also note that considering the emission controls needed for maintenance, along with the controls needed to reach attainment in the first place, is consistent with the goal of promoting a reasonable balance between upwind state controls and local (including all in-state) controls to attain and maintain the NAAQS. As discussed in section IV of this notice, in the ideal world, the states and EPA would have enough information (and powerful enough analytical tools) to allow us to identify a mix of control strategies that would bring every area of the country into attainment at the lowest overall cost to society. Under such an approach, we would evaluate the impact of every emissions source on air quality in all nonattainment areas, the cost of different options for controlling those sources, and the cost-effectiveness of those controls in terms of cost per increment of air quality improvement. Such an approach would obviously make it easier for a state to develop an appropriate set of control requirements for sources located in that state based on (1) the need to bring its own nonattainment areas into attainment and (2) its responsibility under section 110(a)(2)(D) to prevent significant contribution to nonattainment in downwind States and interference with maintenance in those States.

Such an approach would also make it much easier for the Agency to decide on efficiency grounds whether to take action under section 126 (or under section 110(a)(2)(D) if a State failed to meet its obligations under that section) for purposes of either attainment or maintenance of a NAAQS in another State. In the simplest example, we might need to consider a case in which a downwind State with a nonattainment area is seeking reductions from an upwind State based on the claim that emissions from the upwind state are contributing significantly to the nonattainment problem in the downwind State. In such a case, the first question is whether the upwind state should be required to take any action at all, and in the ideal world, it would be simple to answer this question. If emission reductions from sources in the upwind State are more cost-effective than emission reductions in the downwind State—in terms of cost per increment of improvement in air quality in the downwind nonattainment area—then the upwind State would need to take some action to control emissions from sources in that State.[46] On the other hand, if controls on sources in the upwind State are not more cost-effective in terms of cost per increment of improvement in air quality, then the Agency would not take action under sections 126 or 110(a)(2)(D); rather, the downwind State would need to meets its attainment and maintenance needs by controlling sources within its own jurisdiction. Of course, factors other than efficiency, such as equity or practicality, also might affect the decision.

Unfortunately, we do not have adequate information or analytical tools (ideally a detailed linear programming model that fully integrates both control costs and ambient impacts of sources in each State on each of the downwind receptors) to allow us to undertake the analysis described above at this time. However, the Agency believes that CAIR is consistent with this basic approach and will result in upwind States and downwind States sharing appropriate responsibility for attainment and maintenance of the relevant NAAQS, considering efficiency, equity and practical considerations. Under CAIR, the required reductions in upwind States (including those projected to occur after 2015) are highly cost effective, measured in cost-per-ton of emissions reduction, as documented in section IV. This suggests that, regardless of whether the CAIR reductions assist downwind areas in achieving attainment or in subsequently maintaining the relevant NAAQS, the upwind controls will be reasonable in cost relative to a further increment of local controls that, in most cases, will have a substantially higher cost per ton—particularly in areas that need greater local reductions and require reductions from a variety of source types.[47] Thus, we believe that CAIR is consistent with the goal of attaining and maintaining air quality standards in an efficient, as well as equitable, manner.

Another reason for considering both attainment and maintenance needs at this time is EPA's expectation that most nonattainment areas will be able to

[45] As in the NO_X SIP Call rulemaking, EPA interprets the ''interfere with maintenance'' statutory requirement ''much the same as the term 'contribute significantly' '', that is, ''through the same weight-of-evidence approach.'' 63 FR at 57379. Furthermore, we believe the ''interfere with maintenance'' prong may come into play only in circumstances where EPA or the State can reasonably determine or project, based on available data, that an area in a downwind state will achieve attainment, but due to emissions growth or other relevant factors is likely to fall back into nonattainment. *Id.*

[46] This does not mean that the upwind state would be responsible for making all the reductions necessary to bring the downwind State's nonattainment area into attainment; how much would be required of each State is a separate question. Again in the ideal world, we would be able to find the right mix of controls in both states so that attainment would be achieved at the lowest total cost.

[47] Tables describing cost effectiveness of various control measures and programs are provided in section IV. These show that the cost per ton of non-power-sector control options that states might consider for attainment purposes typically is higher than for CAIR controls.

attain the $PM_{2.5}$ and 8-hour ozone standards within the time periods provided under the statute. Considering both types of downwind needs shows that there is a strong basis for CAIR's requirements despite the potential for most receptor areas to attain before all the emission reductions required by CAIR are achieved.

2. By Design, the CAIR Cap and Trade Program Will Achieve Significant Emissions Reductions Prior to the Cap Deadlines

The EPA notes that Phase I of CAIR is the initial step on the slope of emissions reduction (*i.e.*, the ''glide path'') leading to the final control levels. Because of the incentive to make early emission reductions that the cap and trade program provides, reductions will begin early and will continue to increase through Phases I and II. Therefore, all the required Phase II emission reductions will not take place on January 1, 2015, the effective date of the second phase cap. Rather, these reductions will accrue throughout the implementation period, as the sources install controls and start to test and operate them. The resulting glide path of reductions with CAIR Phase II will provide important reductions to areas coming into attainment over the 2010 to 2014 period.[48]

3. Additional Justification for the SO_2 and NO_X Annual Controls

Our modeling indicates that it is very plausible that a significant number of downwind $PM_{2.5}$ receptors are likely to remain in nonattainment in 2010 and beyond. As noted below (Preamble Table VI–10), the Agency has evaluated a wide range of emission control options and found that the average ambient reduction in $PM_{2.5}$ concentrations achievable through aggressive but feasible local controls is 1.26 μg/m³. In the 2010 base case (which does not consider potential local controls or 2010 CAIR controls, but does consider all other emission controls required to be in effect as of that date), nearly half the receptor counties would be in nonattainment by more than this amount. This indicates that nonattainment is of sufficient severity to make it likely that, in the absence of CAIR, many of these areas would need an attainment date extension of at least one year.

Our base case modeling further shows that every upwind state is linked to at least one receptor area projected to have nonattainment of this severity. Tables VI–10 and VI–11. Thus, there is a reasonable likelihood that CAIR controls will be needed from all of the upwind states to prevent significant contribution to these downwind receptors' nonattainment.

Nor is the amount of reduction in excess of what is needed for attainment. We project that even with CAIR controls, almost all of the upwind states in 2010 remain linked with at least one downwind receptor that would not attain by the same substantial margin exceeding the average of aggressive local controls. Tables VI–10 and VI–8. This not only indicates that the 2010 CAIR controls are not excessive, but that local controls will still be necessary for attainment.

In addition, there is potential for residual nonattainment in 2015 in view of the severity of $PM_{2.5}$ levels in some areas, uncertainties about the levels of reductions in $PM_{2.5}$ and precursors that will prove reasonable over the next decade, the potential for up to two 1-year extensions for areas that meet certain air quality levels in the year preceding their attainment date, and historical examples in which areas did not meet their statutory attainment dates for other NAAQS.

With respect to the argument that phase II emission reductions that will be achieved after 2015 are not needed because all receptors will have attained before 2015, we think it likely that some $PM_{2.5}$ nonattainment areas may qualify for 2014 attainment dates and eventually, one-year attainment date extensions, and that there may be residual nonattainment in 2015. We continue to project that nearly half the downwind receptors in the 2015 base case will be in nonattainment by amounts exceeding the average ambient reduction (again, 1.26 μg/m³) attributable to local controls we believe would be aggressive but feasible for 2010. Table VI–11. The history of progress in development of emission reduction strategies and technologies indicates that greater local reductions could be achieved by 2015 than in 2010; nonetheless, this potential nonattainment is of sufficient severity to make it plausible that at least some of these areas will need an extension. In such cases, this would eliminate the issue of timing raised by commenters, since CAIR controls would no longer be following attainment dates.

Our modeling further shows that, in the 2015 base case (which does not include CAIR controls), all the upwind states in the CAIR region are linked to areas projected to exceed the standard by at least 2 μg/m³. Tables VI–11 and VI–8. Given the reasonable potential for continued nonattainment, it is reasonable to require 2015 CAIR controls from each upwind state to prevent significant contribution to nonattainment.

Moreover, even with 2015 CAIR controls (but not attainment SIP controls), almost all of the upwind states remain linked with at least one downwind receptor that would not attain by at least this same substantial margin (at least 1.26 μg/m³). *Id.* This shows that the 2015 CAIR controls are not more than are necessary to attain the NAAQS (and also shows the necessity for local controls in order to attain). Thus, we conclude that the further $PM_{2.5}$ reductions achieved by the second phase cap will likely be needed to assure all relevant areas reach attainment by applicable deadlines.

Even if some of these areas make more progress than we predict, many downwind receptor areas would be likely in 2010 and 2015 to continue to have air quality only marginally better than the standard, and be at risk of returning to nonattainment. Air quality is unlikely to be appreciably cleaner than the standard because many areas will need steep reductions merely to attain, given that we project nonattainment by wide margins (as explained above).

Moreover, we project that without CAIR, $PM_{2.5}$ levels would worsen in 19 downwind receptor counties between 2010 and 2015, reflecting changes in local and upwind emissions. Air Quality Modeling Technical Support Document, November, 2004. This suggests a reasonable likelihood that, without CAIR, these areas would return to nonattainment. See 63 FR at 57379–80 (finding in NO_X SIP Call that upwind emissions interfere with maintenance of 8-hour ozone standard under section 110(a)(2)(D)(i) where increases in emissions of ozone precursors are projected due to growth in emissions generating activity, resulting in receptors no longer attaining the standard). These downwind receptors link to all but two of the upwind states, and the remaining two upwind states are linked to receptors where projected $PM_{2.5}$ levels between 2010 and 2015 improve only slightly, leaving their air quality only marginally in attainment. Response to Comments, section III.C. In light of documented year-to-year variations in $PM_{2.5}$ levels, these receptors would have a reasonable probability of returning to nonattainment in the absence of CAIR.

Emissions trends after 2015 give rise to further maintenance concerns. Between 2015 and 2020, emissions of

[48] A similar glide path will occur prior to the effective date of the Phase I SO_2 cap because this cap will complement and extend the cap that currently exists under the Acid Rain program.

$PM_{2.5}$ and certain precursors are projected to rise. We do not have air quality modeling for 2020. However, for $PM_{2.5}$ and every precursor, the 2015–2020 emission trend is less favorable than the 2010–2015 emission trend. Given the $PM_{2.5}$ increases our air quality modeling found for 19 counties between 2010 and 2015, the emission trends suggest greater maintenance concerns in the 2015–2020 period than during the 2010–2015 period. See Response to Comments section III.C.

Accordingly, we believe that given these projected trends, and the likelihood of only borderline attainment, CAIR controls from every upwind state in the CAIR region are needed to prevent interference with maintenance of the $PM_{2.5}$ standard. The projected upwards pressure on $PM_{2.5}$ concentrations in most receptor areas indicates that the amount of upwind reductions is not more than necessary to prevent interference with maintenance of the standards, again given the likelihood of initial attainment by narrow margins.

4. Additional Justification for Ozone NO_X Requirements

We believe that most 8-hour ozone areas will be able to attain by their attainment deadlines through existing measures, 2009 CAIR NO_X reductions, and additional local measures. However, we also believe that a limited number of downwind receptor areas will remain in nonattainment with the ozone standard after 2010. This is due to the severity of projected ozone levels in certain areas, uncertainties about the levels of emissions reductions in that will prove reasonable over the next decade, and historical difficulties with attaining the 1-hour ozone standard.

For ozone, the historic difficulties that many areas, particularly large urban areas, have experienced in attaining the ozone NAAQS raises the possibility that some areas may not attain by their attainment dates, and may request a voluntary bump up to a higher classification pursuant to section 181(b)(2) to gain an extension, or may fail to attain by the attainment date and be bumped up under section 181(b)(2). These authorities were used in the course of implementing the 1-hour ozone NAAQS.

Our base case modeling (without CAIR, and without state controls implementing the 8-hour standard) projects geographically widespread nonattainment with the 8-hour ozone NAAQS in 2015. Tables VI–12 and VI–13. Five counties that link to 14 upwind states have projected ozone levels that exceed the 8-hour standard by 6 ppb or more, and 20 upwind states are linked to counties projected to exceed the 8-hour standard by more than 4 ppb. These two sets of linkages show that under a scenario in which several of the receptors with the highest ozone levels did not attain, CAIR reductions would be justified to prevent significant contributions from many of the upwind states in the CAIR ozone region.

The fact that receptors show significant nonattainment even after implementation of the phase II CAIR reductions, as shown in Table VI–13, indicates that these reductions would not be more than necessary to prevent significant contribution to nonattainment in residual areas. Even if all ozone nonattainment areas in the CAIR region could achieve reductions sufficient to meet the level of the 8-hour ozone standard in 2009 [49] based on local controls, 2009 CAIR NO_X reductions, and existing programs, we believe that numerous downwind receptor areas would remain close enough to the standard to be at risk of falling back into nonattainment for the reasons discussed below. These receptor areas are linked to all states in the CAIR ozone region.

First, it is highly unlikely that the receptor areas will be able to attain by a wide margin. This is primarily because many of those areas will need substantial emissions reductions merely to attain. This is supported by modeling showing that in the 2010 base case, 30 percent of the receptors are projected to be in nonattainment by the wide margin of 6 ppb or more, indicating the steep emissions reductions necessary just to come into attainment. Table VI–12. We recognize that, unlike the trend in key PM receptor areas, our modeling projects that the ozone levels in ozone receptor areas will improve somewhat between 2010 and 2015 due chiefly to downward trends in NO_X emissions projected under existing requirements. Nonetheless, as shown in detail in the Response to Comments, the projected improvements in ozone levels in the receptor areas are less (often considerably less) than historic variability in monitored 8-hour ozone design values from one three year period to the next.[50] We believe this variability is mostly attributable to changing weather conditions (which significantly affect the rate at which ozone is formed in the atmosphere and movement of ozone after it is formed), rather than variability in the emissions inventory. Thus, absent the second phase CAIR cap, these receptors remain vulnerable to falling back into nonattainment. The receptors for which this is the case link to each of the upwind States in the ozone CAIR region.

IV. What Amounts of SO_2 and NO_X Emissions Did EPA Determine Should Be Reduced?

In today's rule, EPA requires annual SO_2 and NO_X emissions reductions and ozone-season NO_X emissions reductions to eliminate the amount of emissions that contribute significantly to nonattainment of the NAAQS for $PM_{2.5}$ and ozone. The NO_X reductions are phased in beginning in 2009, the SO_2 reductions beginning in 2010, and both caps are lowered in 2015. In this section of the preamble, EPA explains its analysis of the cost portion of the contribute-significantly test, which determines the amount of required emissions reductions. The cost portion requires analysis of whether the control program under review is highly cost effective, and other factors that are discussed below in section IV.A.

In section IV.A of today's preamble, EPA explains its methodology for determining the amounts of SO_2 and NO_X emissions that must be eliminated for compliance with the CAIR. Section IV.A is divided into IV.A.1, IV.A.2, IV.A.3, and IV.A.4. In IV.A.1, EPA explains the methodology that the Agency used to model control costs for evaluation of cost effectiveness. In IV.A.2, EPA describes the methodology that was proposed in the NPR for determining the amounts of emissions that must be eliminated, including an overview of the proposed methodology, a description of the NO_X SIP Call regulatory history in relation to the proposed methodology, and a description of EPA's proposed criteria for determining emission reduction requirements. Section IV.A.3 summarizes some comments received regarding the proposed methodology. Section IV.A.4 describes EPA's evaluation of highly cost-effective SO_2 and NO_X emissions reductions based on controlling EGUs.

Section IV.A.4 is further divided into IV.A.4.a and IV.A.4.b, which address

[49] Attainment deadlines for moderate ozone areas are to be no later than June 2010; an approvable attainment plan must demonstrate the reductions needed for attainment will be achieved by the ozone season in the preceding year.

[50] We recognize that in the absence of substantial evidence, variability alone would not be a sufficient basis for applying the ''interfere with maintenance'' prong of section 110(a)(2)(D). Here, however, where there is a substantial body of historical data documenting the variability in ozone concentrations, we believe it is appropriate to consider variability in determining whether emission reductions from upwind states are necessary to prevent interference with maintenance of the ozone standard in downwind states.

SO_2 and NO_X emission reduction requirements, respectively. Section IV.A.4.a describes EPA's evaluation of highly cost-effective SO_2 reduction requirements, beginning with a summary of the proposal and then describing today's final determination. In IV.A.4.b., EPA describes its evaluation of highly cost-effective NO_X reduction requirements, also beginning with a summary of the proposal and then describing today's final determination. Section IV.A.4.b first addresses annual NO_X reductions, and then addresses ozone season NO_X reductions. The final regionwide CAIR SO_2 and NO_X control levels are provided within section IV.A, while a more detailed description of today's final emission reduction requirements is presented in section IV.D.

In section IV.B of today's preamble, EPA discusses other (non-EGU) sources that the Agency considered in developing today's rule.

Section IV.C of today's preamble explains the schedule for implementing today's SO_2 and NO_X emissions reductions requirements. This section begins with an overview of the schedule (see section IV.C.1), then provides a detailed discussion of the engineering factors that affect timing for control retrofits (section IV.C.2). Within IV.C.2, EPA first describes the NPR discussion of engineering factors including the availability of boilermaker labor as a limitation (IV.C.2.a), then presents some comments received (IV.C.2.b) and EPA's responses (IV.C.2.c). In section IV.C.3, EPA discusses the financial stability of the power sector in relation to the schedule for the CAIR.

Section IV.D of today's preamble provides a detailed description of the final CAIR emission reduction requirements. Regionwide SO_2 and NO_X control levels, projected base case emissions and emissions after the CAIR, and projected emissions reductions are presented. Section IV.D begins with a description of the criteria used to determine final control requirements and provides the details of the final requirements.

A. What Methodology Did EPA Use To Determine the Amounts of SO_2 and NO_X Emissions That Must Be Eliminated?

1. The EPA's Cost Modeling Methodology

The EPA conducted analysis using the Integrated Planning Model (IPM) that indicates that its CAIR SO_2 and NO_X reduction requirements are highly cost effective. Cost effectiveness is one portion of the contribute-significantly test. The EPA uses the IPM to examine costs and, more broadly, analyze the projected impact of environmental policies on the electric power sector in the 48 contiguous States and the District of Columbia. The IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. The EPA used the IPM to evaluate the cost and emissions impacts of the policies required by today's action to limit annual emissions of SO_2 and NO_X and ozone season emissions of NO_X from the electric power sector (on the assumption that all affected States choose to implement reductions by controlling EGUs using the model cap and trade rule).

The EPA conducted analyses for the final CAIR using the 2004 update of the IPM, version 2.1.9. Documentation describing the 2004 update is in the CAIR docket and on EPA's Web site. Some highlights of the 2004 update include: Updated inventory of electric generating units (EGUs) and installed pollution control equipment; updated State emission regulations; updated coal choices available to generating units; updated natural gas supply curves; updated SCR and SNCR cost assumptions; updated assumptions on performance of NO_X combustion controls; updated title IV SO_2 bank assumptions; updated heat rates and SO_2 and NO_X emission rates; and, updated repowering costs.

The National Electric Energy Data System (NEEDS) contains the generation unit records used to construct model plants that represent existing and planned/committed units in EPA modeling applications of the IPM. The NEEDS includes basic geographic, operating, air emissions, and other data on all the generation units that are represented by model plants in EPA's v.2.1.9 update of the IPM.

The IPM uses model run years to represent the full planning horizon being modeled. That is, several years in the planning horizon are mapped into a representative model run year, enabling the IPM to perform multiple-year analyses while keeping the model size manageable. Although the IPM reports results only for model run years, it takes into account the costs in all years in the planning horizon. In EPA's v.2.1.9 update of the IPM, the years 2008 through 2012 are mapped to run year 2010, and the years 2013 through 2017 are mapped to run year 2015.[51] Model outputs for 2009 and 2010 are from the 2010 run year. Model outputs for 2015 are from the 2015 run year.

The EPA used the IPM to conduct the cost-effectiveness analysis for the emissions control program required by today's action. The model was used to project the incremental electric generation production costs that result from the CAIR program. These estimates are used as the basis for EPA's estimate of average cost and marginal cost of emissions reductions on a per ton basis. The model was also used to project the marginal cost of several State programs that EPA considers as part of its base case.

In modeling the CAIR with the IPM, EPA assumes interstate emissions trading. While EPA is not requiring States to participate in an interstate trading program for EGUs, we believe it is reasonable to evaluate control costs assuming States choose to participate in such a program since that will result in less expensive reductions. The EPA's IPM analyses for the CAIR includes all fossil fuel-fired EGUs with generating capacity greater than 25 MW.

The EPA's IPM modeling accounts for the use of the existing title IV bank of SO_2 allowances. The projected EGU SO_2 emissions in 2010 and 2015 are above the cap levels, because of the use of the title IV bank. The annual SO_2 emissions reductions that are achieved in 2010 and 2015 are based on the caps that EPA determined to be highly cost effective, including the existence of the title IV bank.

The final CAIR requires annual SO_2 and NO_X reductions in 23 States and the District of Columbia, and also requires ozone season NO_X reductions in 25 States and the District of Columbia. Many of the CAIR States are affected by both the annual SO_2 and NO_X reduction requirements and the ozone season NO_X requirements.

The EPA initially conducted IPM modeling for today's final action using a control strategy that is similar but not identical to the final CAIR requirements.[52] Many of the analyses for the final CAIR are based on that initial modeling, as explained further below. The control strategy that EPA initially modeled included three additional States (Arkansas, Delaware and New Jersey) within the region required to make annual SO_2 and NO_X reductions. However, these three States are not required to make annual reductions under the final CAIR. (In the ''Proposed Rules'' section of today's **Federal**

[51] An exception was made to the run year mapping for an IPM sensitivity run that examined the impact of a NO_X Compliance Supplement Pool (CSP). In that run the years 2009 through 2012 were mapped to 2010 and 2008 was mapped to 2008.

[52] The EPA began our emissions and economic analyses for the CAIR before the air quality analysis, which affects the States covered by the final rule, was completed

Register, EPA is publishing a proposal to include Delaware and New Jersey in the CAIR region for annual SO_2 and NO_X reductions.) The addition of these three States made a total of 26 States and the District of Columbia covered by annual SO_2 and NO_X caps for the initial model run. The initial model run also included individual State ozone season NO_X caps for Connecticut and Massachusetts, and did not include ozone season NO_X caps for any other States.

The Agency conducted revised final IPM modeling that reflects the final CAIR control strategy. The final IPM modeling includes regionwide annual SO_2 and NO_X caps on the 23 States and the District of Columbia that are required to make annual reductions, and includes a regionwide ozone season NO_X cap on the 25 States and the District of Columbia that are required to make ozone season reductions. The EPA modeled the final CAIR NO_X strategy as an annual NO_X cap with a nested, separate ozone season NO_X cap.

In this section of today's preamble, the projected CAIR costs and emissions are generally derived from the final IPM run reflecting the final CAIR. However, some of EPA's analyses are based on the initial IPM run, described above, which reflected a similar but not identical control strategy to the final CAIR. Analyses that are presented in this section of the preamble that are based on the initial IPM run include: IPM sensitivity runs that examine the effects of using the Energy Information Administration (EIA) natural gas price and electricity growth assumptions; marginal cost effectiveness curves developed using the Technology Retrofitting Updating Model; estimates of average annual SO_2 and NO_X control costs and average non-ozone season NO_X control costs, and projected control retrofits used in the feasibility analysis. The air quality analysis in section VI of today's preamble and the benefits analysis in section X, as well as the analyses presented in the Regulatory Impact Analysis (RIA), are based on emissions projections from the initial IPM run.

The EPA believes that the differences between the initial IPM run that the Agency used for many of the analyses for the CAIR, and the final IPM run reflecting the final CAIR requirements, have very little impact on projected control costs and emissions. For the two IPM runs, projected marginal costs of CAIR annual NO_X reductions in 2009 and 2015 are identical. In addition, for the two IPM runs, projected marginal costs of CAIR annual SO_2 reductions in 2010 and 2015 are almost identical. Also, the 2009 and 2015 projected annual NO_X emissions in the region encompassing the States that are affected by the final CAIR annual NO_X requirements are virtually identical when compared between the two model runs (difference between projected NO_X emissions is less than 1 percent for 2009 and less than 2 percent for 2015). In addition, the 2010 and 2015 projected annual SO_2 emissions in the region encompassing the States that are affected by the final CAIR annual SO_2 requirements are virtually the same when compared between the two runs (difference between projected SO_2 emissions is less than 1 percent for 2010 and less than 2 percent for 2015). These comparisons confirm EPA's belief that the initial IPM run very closely represents the final CAIR program.

The IPM output files for the model runs used in CAIR analyses are available in the CAIR docket. A Technical Support Document in the CAIR docket entitled ''Modeling of Control Costs, Emissions, and Control Retrofits for Cost Effectiveness and Feasibility Analyses'' further explains the IPM runs used in the analyses for section IV of the preamble.

2. The EPA's Proposed Methodology To Determine Amounts of Emissions That Must be Eliminated

a. Overview of EPA Proposal for the Levels of Reductions and Resulting Caps, and Their Timing

In the NPR, the amounts of SO_2 and NO_X emissions reductions that EPA proposed could be cost effectively eliminated in the CAIR region in 2010 and 2015, and the amount of the proposed EGU emissions caps for SO_2 and NO_X that would exist if all affected States achieved those reductions by capping EGU emissions, appear in Tables IV–1 and IV–2, respectively.

TABLE IV–1.—PROJECTED SO_2 AND NO_X EMISSION REDUCTIONS IN THE CAIR REGION IN 2010 AND 2015 FOR THE PROPOSED RULE

[Million Tons] [1]

Pollutant	2010	2015
SO_2	3.6	3.7
NO_X	1.5	1.8

[1] CAIR Notice of Proposed Rulemaking (69 FR 4618, January 30, 2004). The proposed annual SO_2 and NO_X caps covered a 27-State (AL, AR, DE, FL, GA, IL, IN, IA, KS, KY, LA, MD, MA, MI, MN, MO, NJ, NY, NC, OH, PA, SC, TN, TX, VA, WV, WI) plus DC region. In addition, we proposed an ozone-season only cap for Connecticut.

TABLE IV–2.—PROPOSED ANNUAL ELECTRIC GENERATING UNIT SO_2 AND NO_X EMISSIONS CAPS IN THE CAIR REGION

[Million Tons] [1]

Pollutant	2010–2014	2015 and later
SO_2	3.9	2.7
NO_X	1.6	1.3

[1] CAIR Notice of Proposed Rulemaking (69 FR 4618, January 30, 2004). The proposed annual SO_2 and NO_X caps covered a 27-State (AL, AR, DE, FL, GA, IL, IN, IA, KS, KY, LA, MD, MA, MI, MN, MO, NJ, NY, NC, OH, PA, SC, TN, TX, VA, WV, WI) plus DC region. In addition, we proposed an ozone-season only cap for Connecticut.

In the NPR, EPA evaluated the amounts of SO_2 and NO_X emissions in upwind States that contribute significantly to downwind $PM_{2.5}$ nonattainment and the amounts of NO_X emissions in upwind States that contribute significantly to downwind ozone nonattainment. That is, EPA determined the amounts of emissions reductions that must be eliminated to help downwind States achieve attainment, by applying highly cost-effective control measures to EGUs and determining the emissions reductions that would result.

From past experience in examining multi-pollutant emissions trading programs for SO_2 and NO_X, EPA recognized that the air pollution control retrofits that result from a program to achieve highly cost-effective reductions are quite significant and can not be immediately installed. Such retrofits require a large pool of specialized labor resources, in particular, boilermakers, the availability of which will be a major limiting factor in the amount and timing of reductions.

Also, EPA recognized that the regulated industry will need to secure large amounts of capital to meet the control requirements while managing an already large debt load, and is facing other large capital requirements to improve the transmission system. Furthermore, allowing pollution control retrofits to be installed over time enables the industry to take advantage of planned outages at power plants (unplanned outages can lead to lost revenue) and to enable project management to learn from early installations how to deal with some of the engineering challenges that will exist, especially for the smaller units that often present space limitations.

Based on these and other considerations, EPA determined in the NPR that the earliest reasonable deadline for compliance with the final highly cost-effective control levels for reducing emissions was 2015 (taking into consideration the existing bank of title IV SO_2 allowances). First, the Agency confirmed that the levels of SO_2 and NO_X emissions it believed were reasonable to set as annual emissions caps for 2015 lead to highly cost-effective controls for the CAIR region.

Once EPA determined the 2015 emissions reductions levels, the Agency determined a proposed first (interim) phase control level that would commence January 1, 2010, the earliest the Agency believed initial pollution controls could be fully operational (in today's final action, the first NO_X control phase commences in 2009 instead of in 2010, as explained in detail in section IV.C). The first phase would be the initial step on the slope of emissions reductions (the glide-path) leading to the final (second) control phase to commence in 2015. The EPA determined the first phase based on the feasibility of installing the necessary emission control retrofits, as described in section IV.C.

Although EPA's primary cost-effectiveness determination is for the 2015 emissions reductions levels, the Agency also evaluated the cost effectiveness of the first phase control levels to ensure that they were also highly cost effective. Throughout this preamble section, EPA reports both the 2015 and 2010 (and 2009 for NO_X) cost-effectiveness results, although the first phase levels were determined based on feasibility rather than cost effectiveness. The 2015 emissions reductions include the 2010 (and 2009 for NO_X) emissions reductions as a subset of the more stringent requirements that EPA is imposing in the second phase.

b. Regulatory History: NO_X SIP Call

In the NPR, EPA generally followed the statutory interpretation and approach under CAA section 110(a)(2)(D) developed in the NO_X SIP Call rulemaking. Under this interpretation, the emissions in each upwind State that contribute significantly to nonattainment are identified as being those emissions that can be eliminated through highly cost-effective controls.

In the NO_X SIP Call, EPA relied primarily on the application of highly cost-effective controls in determining the amount of emissions that the affected States were required to eliminate. Specifically, EPA developed a reference list of the average cost effectiveness of recently promulgated or proposed controls, and compared the cost effectiveness of those controls to the cost effectiveness of the NO_X SIP Call controls under consideration. In addition, EPA considered several other factors, including the fact that downwind nonattainment areas had already implemented ozone controls but upwind areas generally had not, the fact that some otherwise required local controls would be less cost-effective than the regional controls, and the overall ambient effects of the reductions required in the NO_X SIP Call (63 FR 57399–57403; October 27, 1998).

i. Highly Cost-Effective Controls

In the NO_X SIP Call, EPA presented control costs in 1990 dollars (1990$). For the electric power industry, these expenditures were the increase in annual electric generation production costs in the control region that result from the rule. In the CAIR NPR, SNPR, and today's final action, EPA presents the same type of electric generation as well as other costs in 1999$, and rounds all values related to the cost per ton of air emissions controls to the nearest 100 dollars.

In the NO_X SIP Call, EPA's decision on the amount of required NO_X emissions reductions was that this amount must be computed on the assumption of implementing highly cost-effective controls. The determination of what constituted highly cost effective controls was described as a two-part process: (1) The setting of a dollar-limit upper bound of highly cost-effective emissions reductions; and (2) a determination of what level of control below this upper-bound was appropriate based upon achievability and other factors.

With respect to setting the upper bound of potential highly cost-effective controls, EPA determined this level on the basis of average cost effectiveness (the average cost per ton of pollutant removed). The EPA explained that it relied on average cost effectiveness for two reasons:

> Since EPA's determination for the core group of sources is based on the adoption of a broad-based trading program, average cost effectiveness serves as an adequate measure across sources because sources with high marginal costs will be able to take advantage of this program to lower their costs. In addition, average cost-effectiveness estimates are readily available for other recently adopted NO_X control measures (63 FR 57399).

At that time, EPA acknowledged that average cost effectiveness did not directly address the fact that certain units might have higher costs relative to the average cost of reduction (*e.g.*, units with lower capacity factors tend to have higher costs):

> [I]ncremental cost effectiveness helps to identify whether a more stringent control option imposes much higher costs relative to the average cost per ton for further control. The use of an average cost effectiveness measure may not fully reveal costly incremental requirements where control options achieve large reductions in emissions (relative to the baseline) (63 FR 57399).

Examination of marginal cost effectiveness—which examines what the cost would be of the next ton of reduction after the defined control level—would fill this gap. However, for the NO_X SIP Call rulemaking, adequate information concerning marginal cost effectiveness was not available.

For the NO_X SIP Call, to determine the average cost effectiveness that should be considered to be highly cost effective, EPA developed a ''reference list'' of NO_X emissions controls that are available and of comparable cost to other recently undertaken or planned NO_X measures. The EPA explained that ''the cost effectiveness of measures that EPA or States have adopted, or proposed to adopt, forms a good reference point for determining which of the available additional NO_X control measures can most easily be implemented by upwind States whose emissions impact downwind nonattainment problems.'' (63 FR 57400). The EPA explained that the measures on the reference list had already been implemented or were planned to be implemented, and therefore could be assumed to be less expensive than other measures to be implemented in the future. The EPA found that the costs of the measures on the reference list approached but were below $2,000 per ton (1990$). The EPA concluded that ''controls with an average cost effectiveness [of] less than $2,000 [1990$, or $2,500 (1999$)] per ton of NO_X removed [should be considered] to be highly cost-effective.'' (63 FR 57400). Notably, the reference costs were taken from the supporting analyses used for the regulatory actions covering the NO_X pollution controls—they are what regulatory decision makers and the public believed were the control costs.

Mindful of this $2,000 limit [1990$, or $2,500 (1999$)], EPA considered a control level that would have resulted in estimated average costs of approximately $1,800 (1990$) per ton. However, EPA concluded that because the corresponding level of controls—nominally a 0.12 lb/mmBtu control level—was not well enough established, EPA was ''not as confident about the robustness'' of the cost estimates. Moreover, EPA expressed concern that its ''level of comfort'' was not as high as it would have liked that the nominal 0.12 lb/mmBtu control level ''will not lead to installation of SCR technology at a level and in a manner that will be difficult to implement or result in reliability problems for electric power generation'' (63 FR 57401).

Accordingly, EPA selected the next control level that it had evaluated—a nominal 0.15 lb/mmBtu level—which would result in an average cost of approximately $1,500 [1990$, or $1,900 (1999$)] per ton. The EPA determined that this control level did not present the uncertainty concerns associated with the 0.12 level. The EPA added, in this 1998 rule: ''With a strong need to implement a program by 2003 that is recognized by the States as practical, necessary, and broadly accepted as highly cost-effective, the Agency has decided to base the emissions budgets for EGUs on a 0.15 * * * level.'' (63 FR 57401—57402). The EPA summarized its approach as determining ''the required emission levels * * * based on the application of NO_X controls that achieve the greatest feasible emissions reduction while still falling within a cost-per-ton reduced range that EPA considers to be highly cost-effective.* * *'' (63 FR 57399).

The bulk of the cost for reducing NO_X emissions for EGUs is in the capital investment in the control equipment, which would be the same whether controls are installed for ozone season only, or for annual controls. The increased costs to run the equipment annually instead of only in the ozone season is relatively small. Although the NO_X SIP Call is an ozone season NO_X reduction program, most of the NO_X control costs on the reference list are for annual reductions. If the NO_X SIP Call were an annual program instead of seasonal, its average control costs would be lower, relative to the annual control costs in the reference list.

ii. Other Factors

In the NO_X SIP Call, although considering air quality and cost to be the primary factors for determining significant contribution, EPA identified several other factors that it generally considered. As one factor, EPA reviewed ''overall considerations of fairness related to the control regimes required of the downwind and upwind areas,'' particularly, the fact that the major urban nonattainment areas in the East had implemented controls on virtually all portions of their inventory of ozone precursors, but upwind sources had not implemented reductions intended to reduce their impacts downwind (63 FR 57404).

As another factor, EPA generally considered ''the cost effectiveness of additional local reductions in the * * * ozone nonattainment areas.'' The EPA included in the record information that nationally, on average, additional local measures would cost more than the cost of the upwind controls required under the NO_X SIP Call. This consideration further indicated that the regional controls under the NO_X SIP Call were highly cost effective (63 FR 57404).

In addition, EPA conducted air quality modeling to determine the impact of the controls, and found that they benefitted the downwind areas without being more than necessary for those areas to attain (63 FR 57403—57404).

c. Proposed Criteria for Emissions Reduction Requirements

i. General Criteria

In the CAIR NPR, EPA proposed criteria for determining the appropriate levels of annual emissions reductions for SO_2 and NO_X and ozone-season emissions reductions for NO_X. The EPA stated that it considers a variety of factors in evaluating the source categories from which highly cost-effective reductions may be available and the level of reduction assumed from that sector. These include:

- The availability of information,
- The identification of source categories emitting relatively large amounts of the relevant emissions,
- The performance and applicability of control measures,
- The cost effectiveness of control measures, and
- Engineering and financial factors that affect the availability of control measures (69 FR 4611).

Further, EPA stated that overall, ''We are striving * * * to set up a reasonable balance of regional and local controls to provide a cost-effective and equitable governmental approach to attainment with the NAAQS for fine particles and ozone.'' (69 FR 4612)

The EPA has used these types of criteria in a number of efforts to develop regional and national strategies to reduce interstate transport of SO_2 and NO_X. Starting in 1996, EPA performed analysis and engaged in dialogue with power companies, States, environmental groups and other interested groups in the Clean Air Power Initiative (CAPI).[53] In that study of national emission reduction strategies, EPA initially considered an emissions cap based on a 50 percent reduction in SO_2 emissions from title IV levels (*i.e.*, 4.5 million tons nationwide) in 2010. For NO_X, EPA initially looked at ozone season and non-ozone season caps. Commencing in 2000, the ozone season emissions cap would be based on an emission rate of 0.20 lb/mmBtu, and in 2005, the ozone season cap would be reduced to a level based on 0.15 lb/mmBtu (these cap levels would be similar to the phased caps adopted by the Ozone Transport Commission (OTC) States). The non-ozone season cap would be based on the proposed title IV phase II NO_X rule. The EPA also considered other options in the CAPI study, including setting NO_X caps based on emission rates of 0.20 lb/mmBtu and 0.25 lb/mmBtu; setting NO_X caps based on rates of 0.15 lb/mmBtu and 0.20 lb/mmBtu but lowering the SO_2 allowance cap by 60 percent instead of 50 percent; and, keeping a NO_X cap based on a rate of 0.15 lb/mmBtu but lowering the SO_2 allowance cap by 50 percent in 2005 instead of in 2010.

The EPA did a follow-up study in 1999 and discussed those results with various stakeholder groups, as well.[54] That study considered a variety of SO_2 emission caps ranging from a 40 percent reduction from title IV cap levels in 2010 to a 55 percent reduction from title IV cap levels in 2010. The 1999 study did not consider additional reductions in NO_X emissions beyond those required under the NO_X SIP Call.

In the last several years, EPA has performed significant additional analysis in support of the proposed Clear Skies Act.[55] That legislation, proposed in 2002 and 2003, would include nationwide SO_2 caps of 4.5 million tons in 2010 and 3.0 million tons in 2018 (*i.e.*, 50 percent and 67 percent reductions from title IV cap levels). The Clear Skies Act also includes a two-phase, two-zone NO_X emission cap program, with the first phase in 2008 and the second phase in 2018. In the 2003 legislation, the first phase NO_X caps would result in effective NO_X emissions rates of 0.16 lb/mmBtu in the east and 0.20 lb/mmBtu in the west, and the second phase would result in effective emission rates of 0.12 lb/mmBtu in the east and 0.20 lb/mmBtu in the west.

[53] U.S. Environmental Protection Agency, Office of Air and Radiation, EPA's Clean Air Power Initiative, October 1996.

[54] U.S. Environmental Protection Agency, Office of Air and Radiation, Analysis of Emission Reduction Options for the Electric Power Industry, March 1999.

[55] EPA's Clear Skies Act analysis is on the web at: *http://www.epa.gov/air/clearskies/technical.html.*

ii. Reliance on Average and Marginal Cost Effectiveness

In the CAIR NPR, EPA supported the conclusion that its emissions caps are highly cost effective based upon ''(1) comparison to the average cost effectiveness of other regulatory actions and (2) comparison to the marginal cost effectiveness of other regulatory actions.'' (69 FR 4585). We supplemented these comparisons of cost-effectiveness tables with an auxiliary evaluation of the marginal costs curves, which allowed us to show that the selected control levels would be ''below the point at which there would be significant diminishing returns on the dollars spent for pollution control.'' (69 FR 4614).

Although in the NO_X SIP Call, EPA based the required controls on average cost alone, in today's rule, EPA uses both average and marginal costs, including an evaluation of the marginal cost curves. At the time of the NO_X SIP Call, marginal cost information was not as readily available. Today, such information is available for both SO_2 and NO_X controls, although marginal cost information remains more limited and EPA has had to specifically develop marginal cost estimates for use in this rulemaking.

Marginal costs are a useful measure of cost effectiveness because they indicate how much any additional level of control at the margin will cost relative to other actions that are available. Using both average and marginal control costs, provides a more complete picture of the costs of controls than using average costs alone. Average costs provide a means for a straightforward comparison between the CAIR and other emissions reductions programs for which average costs are generally the only type of costs available. Where marginal cost information is available, it enables EPA to compare the costs of the CAIR at the stringency level being considered to the costs of the last increment of control in other programs. Moreover, evaluation of marginal cost curves allows us to corroborate that the selected level of stringency of the selected program stops short of the point where the returns begin to diminish significantly.

Projected marginal cost information for controlling emissions from EGUs is now available for some State programs, because EPA includes the programs in its base case power sector modeling using the IPM to develop the incremental costs of electricity production for the CAIR. Marginal EGU control costs from State programs modeled using the IPM were compared to projected marginal EGU control costs under the CAIR, as discussed in more detail below.

3. What Are the Most Significant Comments That EPA Received About Its Proposed Methodology for Determining the Amounts of SO_2 and NO_X Emissions That Must Be Eliminated, and What Are EPA's Responses?

Some commenters took issue with EPA's reliance on cost-per-ton-of-emissions-reductions as the metric for determining cost effectiveness. These commenters observed that this metric does not take into account that any given ton of pollutant reduction may have different impacts on ambient concentration and human exposure. Some of these commenters advocated use of a metric based on cost per unit of pollutant concentration reduced. Another stated that EPA should account for cost effectiveness based on geographical location relative to the area of nonattainment.

Still other commenters took a contrasting view. They argued that a metric based on cost-per-ambient-impact might be useful in justifying control cost effectiveness for source categories within an individual nonattainment area as part of an attainment SIP, but not for evaluating costs of controlling long-range transport. These commenters stated that it is impractical to calculate cost effectiveness of control on the basis of cost per unit reduction in ambient concentration. One queried: ''Where would the ambient reduction be measured? 100 miles downwind? 1,500 miles downwind?''

The EPA agrees that optimally, the cost-per-ambient-impact of controls could play a major role in determining upwind control obligations (although equitable considerations and other factors identified in the NO_X SIP Call rulemaking and today's action may also play a role). The EPA recognized the potential importance of this factor during the NO_X SIP Call rulemaking and endeavored to develop technical information to support it. However, in that rulemaking, EPA was not able to develop an approach to quantify, with sufficient accuracy, cost-per-ambient impact because the NO_X SIP Call region was large—covering approximately half of the continental U.S. and including approximately half the States—and many upwind States with different emissions inventories had widely varied impacts on many different nonattainment areas downwind.

This problem—the complexity of the task and the dearth of analytic tools—remains today for both $PM_{2.5}$ and 8-hour ozone regional transport. Not surprisingly, no commenter presented to EPA the analytic tools, which we would expect would consist of a complex, computerized program that could integrate, on a State-by-State basis, both control costs and ambient impacts by each State on each of its downwind receptors under the CAIR control scenario.

In the absence of a scientifically defensible, practicable method for implementing a program design approach based on the cost-per-ambient-impact of emissions reductions, EPA is not able to employ such an approach. However, EPA believes it appropriate to continue to examine ways to develop such an approach for future use.

A few commenters suggested that EPA should use a cost-benefit analysis for determining reduction levels. One noted that cost-benefit analysis can help find the reduction levels that maximize societal net benefit (benefits minus costs), and suggested the Agency should compare the marginal cost of each ton of pollutant reduced to the marginal benefit achieved, as well as compare the total costs to the total benefits. Another stated that an optimal allocation of resources is where the marginal cost equals the marginal benefit, and observed that comparing the average cost to the average benefit of the controls proposed in the CAIR NPR yields an average benefit significantly higher than the average cost. This commenter concluded that EPA should require controls beyond the controls described in the NPR as highly cost effective.

Although EPA strongly agrees that examination of costs and benefits is very useful, in today's rulemaking, EPA does not interpret CAA section 110(a)(2)(D) to base the amount of emissions reductions on benefits other than progress towards attainment of the $PM_{2.5}$ or the 8-hour ozone NAAQS. The EPA's interpretation does, however, use cost effectiveness per ton of pollutant reduced, and we are using that analytic tool for setting SO_2 and NO_X emission reduction requirements. Additionally, EPA has prepared a cost-benefit analysis to inform the Agency and public of the many other important impacts of this rulemaking.

A few commenters suggested that the Agency should set its NO_X and SO_2 reduction requirements based on Best Available Control Technology (BACT) emission rates for EGUs. Although not clearly stated, the commenters appear to suggest BACT level controls for both existing and new units.

The emission reduction requirements that EPA determined are based on the application of highly cost-effective controls that are a step that the Agency is taking at this time to eliminate emissions that contribute significantly to nonattainment of the ozone and fine particle NAAQS. As explained elsewhere, this step is reasonable in light of the current status of implementation for those NAAQS.

Basing emission reduction requirements on a presumption of BACT emission rates across the board would require scrubbers and SCRs on all coal-fired units and SCRs on all gas-fired and oil-fired units. The cost of these controls would vary considerably from source to source, be expensive for many sources, and may cause substantial fuel switching to natural gas and closure of smaller coal-fired units. Having considered this suggestion for deeper regional reductions that would not be as cost effective as the highly cost-effective reductions in today's rule, EPA believes that a more tailored approach, such as the CAIR level control as well as local controls under SIPs (where necessary), is a more reasonable approach to achieving the level of ambient improvement needed for attainment throughout the United States.

4. The EPA's Evaluation of Highly Cost-Effective SO_2 and NO_X Emissions Reductions Based on Controlling EGUs

a. SO_2 Emissions Reductions Requirements

i. CAIR Proposal for SO_2

The NPR focused primarily on determining highly cost-effective amounts of emissions reductions based on, as in the NO_X SIP Call, comparison to reference lists of the cost effectiveness of other regulatory controls. In the NPR, EPA developed reference lists for both the average cost effectiveness and the marginal cost effectiveness of those other controls. These reference lists indicated that the average annual costs per ton of SO_2 removed ranged from $500 to $2,100; and marginal costs of SO_2 removal ranged from $800 to $2,200.

Moreover, EPA further considered the cost effectiveness of alternative stringency levels for this regulatory proposal. That is, EPA examined changes in the marginal cost curve at varying levels of emissions reductions. The EPA determined in the NPR that the ''knee'' in the marginal cost-effectiveness curve—the point at which the marginal cost per ton of SO_2 removed begins to increase at a noticeably higher rate—appears to start above $1,200 per ton (69 FR 4613—4615).

In the NPR, EPA then provided further analysis of a two-phase SO_2 reduction program. The final (second) phase, in 2015, would reduce SO_2 emissions in the CAIR region by the amount that results from making a 65 percent reduction from the title IV Phase II allowance levels (taking into consideration the existing bank of title IV SO_2 allowances). The first phase, in 2010, would reduce SO_2 emissions in the CAIR region by a lesser amount, *i.e.*, a 50 percent reduction from title IV Phase II allowance levels (again, taking into consideration the banked title IV SO_2 allowances). The EPA developed this target SO_2 control level for further evaluation because, based on all of the earlier work performed on multi-pollutant power plant reduction programs and general consideration, with technical support, of overall emissions reductions, costs to industry and the general public, ambient improvement, and consistency with the emerging $PM_{2.5}$ implementation program, we believed it would meet the criteria set forth above.

Then, EPA conducted cost analyses of this control level using the IPM as well as additional analysis of the implications of this control level to determine if it did indeed meet those criteria. The IPM analysis considered the increase in annual electric generation production costs in the CAIR region that result from the rule. The EPA evaluated the cost effectiveness of the final phase (2015) cap to determine if it is highly cost effective; and, we also evaluated the cost effectiveness of the 2010 cap. The EPA used the IPM to estimate cost effectiveness of the CAIR in the future. The IPM incorporates projections of future electricity demand, and thus heat input growth. The EPA's IPM analyses for the CAIR includes all fossil fuel-fired EGUs with capacity greater than 25 MW. A description of the IPM is included elsewhere in this preamble, and a detailed model documentation is in the docket.

The SO_2 annual control costs that were presented in the CAIR NPR were average costs of $700 per ton and $800 per ton for years 2010 and 2015, respectively, and marginal costs of $700 per ton and $1,000 per ton for years 2010 and 2015. In addition, the NPR included the results of sensitivity analyses that examined costs of the proposed SO_2 controls based on the Energy Information Administration's projections for electricity growth and natural gas prices. These sensitivity analyses showed marginal SO_2 control costs of $900 per ton and $1,100 per ton for years 2010 and 2015, respectively. The EPA proposed to consider the SO_2 emissions reductions proposed in the NPR as highly cost effective because they were consistent with the lower end of the reference list range of cost per ton of SO_2 reduction for controls on both an average and a marginal cost basis (69 FR 4613—4615).

ii. Analysis of SO_2 Emission Reduction Requirements for Today's Final Rule

(I) Reference Lists of Cost-Effective SO_2 Controls

For today's action, EPA updated the reference list of controls included in the NPR of the average and marginal costs per ton of recent SO_2 control actions. The EPA systematically developed a list of cost information from both recent actions and proposed actions. The EPA compiled cost information for actions taken by the Agency, and examined the public comments submitted after the NPR was published, to identify all available control cost information to provide the updated reference list for today's preamble. The updated reference list includes both average and marginal costs of control, to which EPA compares the CAIR control costs, and the list represents what regulatory decision makers and/or the public believes are the control costs.[56]

Table IV–3 provides average costs of SO_2 controls. This table includes average costs for recent BACT permitting decisions for SO_2. Under EPA's New Source Review (NSR) program, if a company is planning to build a new plant or modify an existing plant such that a significant net increase in emissions will occur, the company must obtain a NSR permit that addresses controls for air emissions. BACT is the type of control required by the NSR program for existing sources in attainment areas. The BACT decisions are determined on a case-by-case basis, usually by State or local permitting agencies, and reflect consideration of average and incremental cost effectiveness. These decisions are relevant for EPA's reference list of average costs of SO_2 controls, because they represent cost-effective controls that have been demonstrated.

[56] The updated reference list includes estimated average costs for SO_2 reductions from EGUs under best available retrofit technology (BART) requirements. The BART rule was proposed and has not been finalized (69 FR 25184; May 5, 2004).

TABLE IV–3.—AVERAGE COSTS PER TON OF ANNUAL SO_2 CONTROLS

SO_2 control action	Average cost per ton
Best Available Control Technology (BACT) Determinations	[1] $400–$2,100
Nonroad Diesel Engines and Fuel	[2] $800
Proposed Best Available Retrofit Technology (BART) for Electric Power Sector	[3] $2,600–$3,400

[1] These numbers reflect a range of cost-effectiveness data entered into EPA's RACT/BACT/LAER Clearinghouse (RBLC) for add-on SO_2 controls (*www.epa.gov/ttn/catc/*). We identified actions in the data base for large, utility-scale, coal-fired boiler units for which cost effectiveness data were reported. The range of costs shown here is for boilers ranging from 30 MW to an estimated 790 MW (we used a conversion factor of 10 mmBtu/hr = 1 MW for units for which size was reported in mmBtu/hr). Emission limits for these actions ranged from 0.10 lb/mmBtu to 0.27 lb/mmBtu. Add-on controls reported for these units are dry or wet scrubbers (in one case with added alkali and in one case with a baghouse). Where the dollar-year was not reported we assumed 1999 dollars. The cost range presented in the NPR was $500–$2,100–today's range includes additional BACT costs that were entered into the clearinghouse after the NPR was published.

[2] Control of Emissions of Air Pollution From Nonroad Diesel Engines and Fuel; Final Rule (69 FR 39131; June 29, 2004). The value in this table represents the long-term cost per ton of emissions reduced from the total fuel and engine program (cost per ton of emissions reduced in the year 2030). 1999$ per ton.

[3] The EPA IPM modeling 2004, available in the docket. The EPA modeled the Regional Haze Requirements as source specific limits (90 percent SO_2 reduction or 0.1 lb/mmBtu rate; except the five state WRAP region for which we did not model SO_2 controls beyond what is done for the WRAP cap in the base case modeling). Estimated average costs based on this modeling are $2,600 per ton in 2015 and $3,400 per ton in 2020. 1999$ per ton.

Table IV–4 provides the marginal cost per ton of recent State and regional decisions for annual SO_2 controls.

TABLE IV–4.—MARGINAL COSTS PER TON OF ANNUAL SO_2 CONTROLS

SO_2 control action	Marginal cost per ton
New Hampshire Rule	[1] $600
WRAP Regional SO_2 Trading Program	[2] $1,100–$2,200

[1] The EPA IPM base case modeling August 2004, available in the docket. (1999$ per ton). We modeled New Hampshire's State Bill ENV-A2900, which caps SO_2 emissions at all existing fossil steam units.

[2] "An Assessment of Critical Mass for the Regional SO_2 Trading Program," prepared for Western Regional Air Partnership Market Trading Forum by ICF Consulting Group, September 27, 2002, available in the docket. This analysis looked at the implications of one or more States choosing to opt-out of the WRAP regional SO_2 trading program. (1999$ per ton)

(II) Cost Effectiveness of the CAIR Annual SO_2 Reductions

In the NPR, EPA evaluated an annual SO_2 control strategy based on a specified level of emissions reductions from EGUs. Available information indicated that emissions reductions from this industry would be the most cost effective. (As noted elsewhere, EPA considered control strategies for other source categories, but concluded that they would not qualify as highly cost-effective controls.) Of course, under today's rule, although EPA calculates the amount of emissions reductions States must achieve by evaluation of the EGU control strategy, States remain free to achieve those reductions by implementing controls on any sources they wish.

For today's action, EPA updated the predicted annual SO_2 control costs included in the NPR. The EPA analyzed the costs of the CAIR using an updated version of the IPM (documentation for the IPM update is in the docket). Further, EPA modified the modeling to match the final CAIR strategy (see section IV.A.1 for a description of EPA's CAIR IPM modeling).

The EPA also updated its analysis of the sensitivity of the marginal cost results to assumptions of higher electric growth and natural gas prices than we used in the base case. These sensitivity analyses were based on the Energy Information Administration's Annual Energy Outlook for 2004.[57]

In determining whether our control strategy is highly cost effective, EPA believes it is important to account for the variable levels of cost effectiveness that these sensitivity analyses indicate may occur if electricity demand or natural gas prices are appreciably higher than assumed in the IPM. Those two factors are key determinants of control costs and, over the relatively long implementation period provided under today's action, a meaningful degree of risk arises that these factors may well vary to the extent indicated by the sensitivity analyses. As a result, EPA wanted to examine the marginal costs that would occur under the scenarios modeled in the sensitivity analyses to see how they differed from the costs using EPA's assumptions.

Table IV–5 provides the average and marginal costs of annual SO_2 reductions under the CAIR for 2010 and 2015. (When presenting estimated CAIR control costs in section IV of this preamble, EPA uses "Main Case" to indicate the primary CAIR IPM analyses, as differentiated from other IPM analyses such as sensitivity runs used to examine the impacts of varying assumptions about natural gas price and electric growth.)

TABLE IV–5.—ESTIMATED COSTS PER TONS OF SO_2 CONTROLLED UNDER CAIR, CAP LEVELS BEGINNING IN 2010 AND 2015 [1]

Type of cost effectiveness	2010	2015
Average Cost—Main Case	$500	$700
Marginal Cost—Main Case	700	1,000

[57] The EPA used the difference between EIA's estimates for well-head natural gas prices and minemouth coal prices to determine the sensitivity of IPM's results to higher natural gas prices. The EPA describes this sensitivity analysis as "EIA natural gas prices". For electric demand, we replaced EPA's assumed annual growth of 1.6 percent with EIA's projection of annual growth of 1.8 percent.

TABLE IV–5.—ESTIMATED COSTS PER TONS OF SO_2 CONTROLLED UNDER CAIR, CAP LEVELS BEGINNING IN 2010 AND 2015 [1]—Continued

Type of cost effectiveness	2010	2015
Sensitivity Analysis: Marginal Cost Using EIA Electric Growth and Natural Gas Prices	800	1,200

[1] The EPA IPM modeling 2004, available in the docket. $1999 per ton.

These estimated SO_2 control costs under the CAIR reflect annual EGU SO_2 caps of 3.6 million tons in 2010 and 2.5 million tons in 2015 within the CAIR region. Based on IPM modeling, EPA projects that SO_2 emissions in the CAIR region will be about 5.1 million tons in 2010 and 4.0 million tons in 2015. The projected emissions are above the cap levels because of the use of the existing title IV bank of SO_2 allowances. Average costs shown for 2015 are an estimate of the average cost per ton to achieve the total difference in projected emissions between the base case conditions and the CAIR in the year 2015 (the 2015 average costs are not based on the increment in reductions between 2010 and 2015). (A more detailed description of the final CAIR SO_2 and NO_X control requirements is provided below in today's preamble.)

(III) SO_2 Cost Comparison for CAIR Requirements

The EPA believes that if an SO_2 control strategy has a cost effectiveness that is at the low end of the updated reference tables, the approach should be considered to be highly cost effective. The costs in the reference range should be considered to be cost effective because they represent actions that have already been taken to reduce emissions. In deciding to require these actions, policymakers at the local, State and Federal levels have determined them to be cost-effective reductions to limit or reduce emissions. Thus, costs at the bottom of the range must necessarily be considered highly cost effective.

Today's action requires SO_2 emissions reductions (or an EGU emissions cap) in 2015. The EPA has determined that those emissions reductions are highly cost effective. In addition, today's action requires that some of those SO_2 emissions reductions (or a higher EGU emissions cap) be implemented by 2010. The EPA has examined the cost effectiveness of implementing those earlier emissions reductions (or cap) by 2010, and determined that they are also highly cost effective.

The cost of the SO_2 reductions required under today's action—if the States choose to implement those reductions through EGUs, for which the most cost-effective reductions are available—on average and at the margin, are at the lower end of the range of cost effectiveness of other, recent SO_2 control requirements.[58] This is true for our analysis of both the costs EPA generally expects as well as the somewhat higher costs that would result from higher than expected electricity demand and natural gas prices, as indicated in the sensitivity analyses that EPA has done.

Specifically, the average cost effectiveness of the SO_2 requirements is $700 per ton removed in 2015. This amount falls toward the low end of the reference range of average costs per ton removed of $400 to $3,400. Similarly, the marginal cost effectiveness of the SO_2 requirements ranges from $1,000 to $1,200 for 2015 (with the higher end of the range based on the sensitivity analyses). These amounts fall toward the lower end of the reference range of marginal cost per ton removed of $600 to $2,200.

The EPA believes that selecting as highly cost-effective amounts toward the lower end of our average and marginal cost ranges for SO_2 and NO_X control is appropriate because today's rulemaking is an early step in the process of addressing $PM_{2.5}$ and 8-hour ozone nonattainment and maintenance requirements. The CAA requires States to submit section 110(a)(2)(D) plans to address interstate transport, and overall attainment plans to ensure the NAAQS are met in local areas. By taking the early step of finalizing the CAIR, we are requiring a very substantial air emission reduction that addresses interstate transport of $PM_{2.5}$ as well as a further reduction in interstate transport of ozone beyond that required by the NO_X SIP Call Rule. Much of the air quality improvement resulting from reduced transport is likely to occur through broad and deep emissions reductions from the electric power sector, which has been a major part of the transport problem. Other air quality benefits will occur as the result of Federal mobile source regulations for new sources, which cover passenger vehicles and light trucks, heavy-duty trucks and buses, and non-road diesel equipment.

Against this backdrop of Federal actions that lower air emissions (as well as some substantial State control programs), States will develop plans designed to achieve the standards in their local nonattainment areas. The EPA has not yet promulgated rules interpreting the CAA's requirements for SIPs for $PM_{2.5}$ and ozone nonattainment areas,[59] nor have States developed plans to demonstrate attainment. As a result, there are significant uncertainties regarding potential reductions and control costs associated with State plans. We believe that some areas are likely to attain the standards in the near term through early CAIR reductions and local controls that have costs per ton similar to the levels we have determined to be highly cost effective. We expect that other areas with higher $PM_{2.5}$ or ozone levels will determine through the attainment planning process that they need greater emissions reductions, at higher costs per ton, to reach attainment within the CAA's timeframes. For those areas, States will need to assess targeted measures for achieving local attainment in a cost-effective (but not necessarily highly cost-effective) manner, in combination with the CAIR's significant reductions. Given the uncertainties that exist at this early stage of the implementation process, EPA believes this rule is a rational approach to determining the highly cost-effective reductions in $PM_{2.5}$ and ozone precursors that should be required for interstate transport purposes.

As discussed above, the Agency believes this approach is consistent with our action in the NO_X SIP Call. While the cost level selected for the NO_X SIP Call was not at the low end of the reference range of costs, if the NO_X SIP Call costs were for annual rather than seasonal controls they would have been lower relative to the annual control costs on the list. This would make the relationship between the cost of the NO_X SIP Call and the reference costs used in that rulemaking, more similar to relative costs of CAIR compared to its reference lists. Also, significant local controls for meeting the 1-hour ozone standard had already been adopted in many areas.

Although EPA's primary cost-effectiveness determination is for the 2015 emissions reductions levels, the Agency also evaluated the cost effectiveness of the interim phase control levels to ensure that they were also highly cost effective. For the SO_2 requirements for 2010, the average cost effectiveness is $500 per ton removed, and the marginal cost effectiveness

[58] The updated reference list of average SO_2 control costs includes estimated average EGU costs under BART. The BART rule has been proposed but not finalized (69 FR 25184; May 5, 2004).

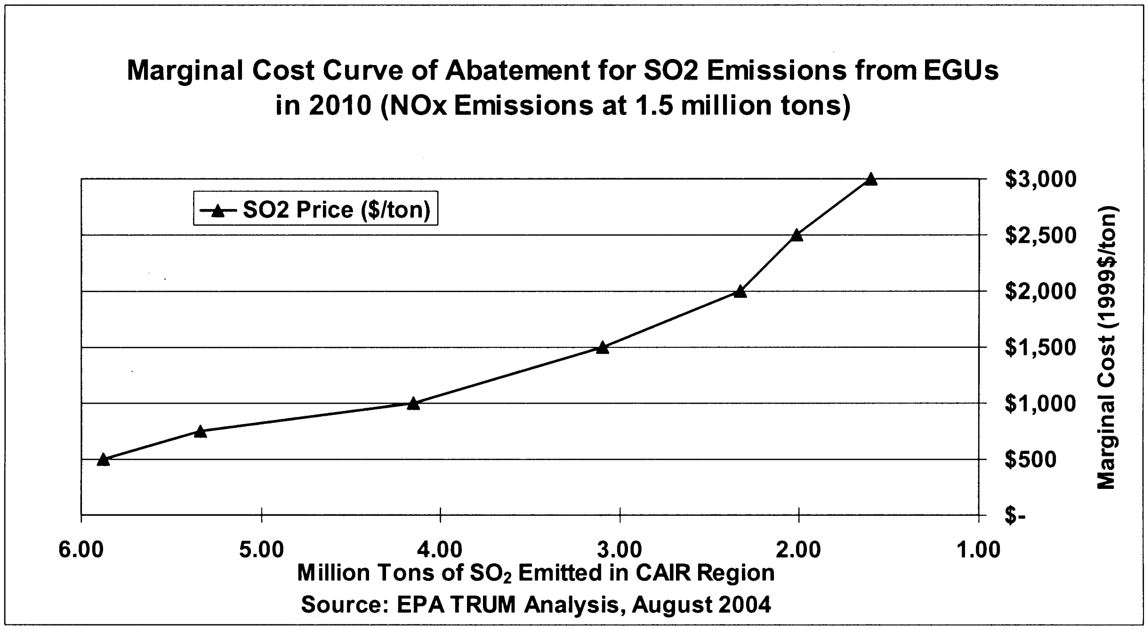
[59] EPA did promulgate Phase I of the ozone implementation rule in April 2004 (69 FR 23951; April 30, 2004) but has not issued Phase II of the rule, which will interpret CAA requirements relating to local controls (*e.g.,* RACT, RACM, RFP).

ranges from $700 to $800. The 2010 costs indicate that the interim phase CAIR reductions are also highly cost-effective.

(IV) Cost Effectiveness: Marginal Cost Curves for SO_2 Control

As noted above, the Agency also considered another factor to corroborate its conclusion concerning the cost effectiveness of the selected levels of control:

Figure IV-1.

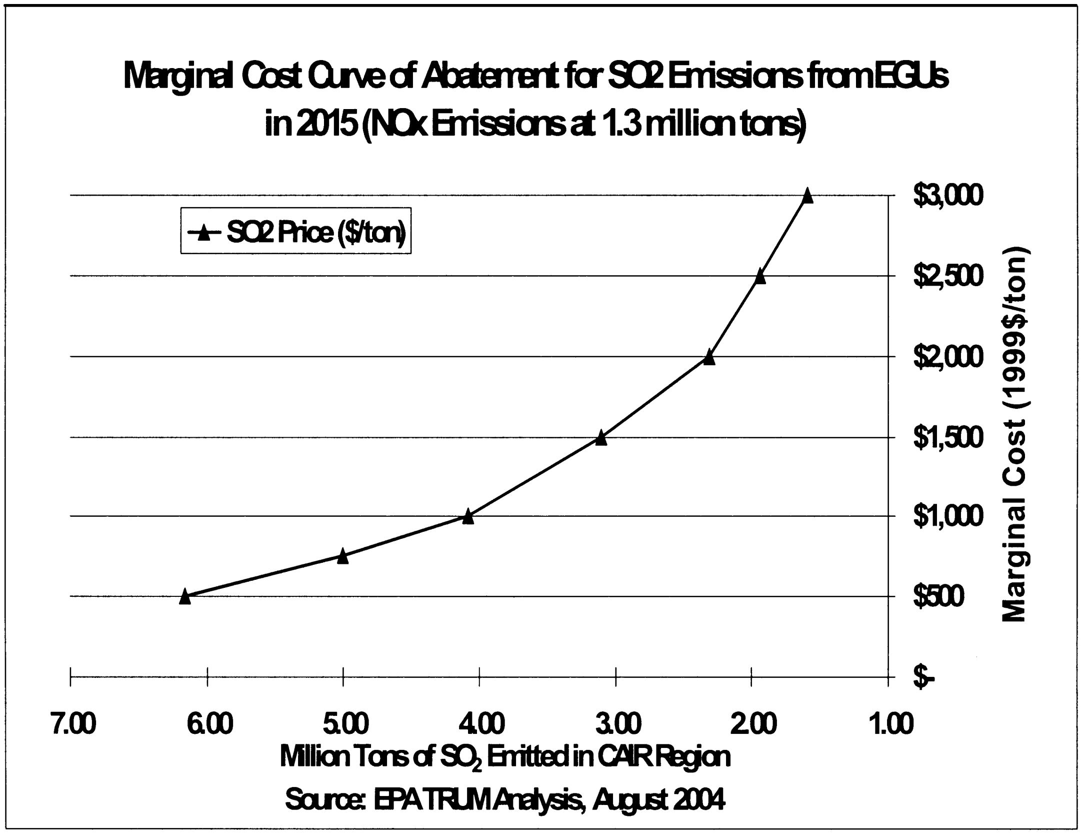


The cost effectiveness of alternative stringency levels for today's action. Specifically, EPA examined changes in the marginal cost curve at varying levels of emissions reductions for EGUs. Figure IV–1 shows that the ''knee'' in the 2010 marginal cost-effectiveness curve—the point where the cost of controlling a ton of SO_2 from EGUs is increasing at a noticeably higher rate—appears to occur at about $2,000 per ton of SO_2. Figure IV–2 shows that the ''knee'' in the 2015 marginal cost-effectiveness curve also appears to occur at about $2,000 per ton of SO_2. (As discussed above, the projected marginal costs of SO_2 reductions for the CAIR are $700 per ton in 2010 and $1,000 per ton in 2015.) The EPA used the Technology Retrofitting Updating Model (TRUM), a spreadsheet model based on the IPM, for this analysis. (The EPA based these marginal SO_2 cost-effectiveness curves on the electric growth and natural gas price assumptions in the main CAIR IPM modeling run. Marginal cost effectiveness curves based on other electric growth and natural gas price assumptions would look different, therefore it would not be appropriate to compare the curves here to the marginal costs based on the IPM modeling sensitivity run that used EIA assumptions.) These results make clear that this rule is very cost effective because the control level is below the point at which the cost begins to increase at a significantly higher rate.

In this manner, these results corroborate EPA's findings above concerning the cost effectiveness of the emissions reductions.[60]

[60] EPA is using the knee in the curve analysis solely to show that the required emissions reductions are very cost effective. The marginal cost curve reflects only emissions reduction and cost information, and not other considerations. We note that it might be reasonable in a particular regulatory action to require emissions reductions past the knee of the curve to reduce overall costs of meeting the NAAQS or to achieve benefits that exceed costs. It should be noted that similar analysis for other source categories may yield different curves.

Figure IV -2.



b. NO_X Emissions Reductions Requirements

i. The CAIR Proposal for NO_X and Subsequent Analyses for Regionwide Annual and Ozone Season NO_X Control Levels

In this section, EPA describes its proposed method for determining regionwide NO_X control levels and the method used for the final CAIR.

In the CAIR NPR, EPA updated the reference list included in the NO_X SIP Call for the average annual cost effectiveness of recent or proposed NO_X controls, and determined that these amounts ranged from approximately $200 to $2,800. In addition, in the NPR, EPA developed a reference list for marginal annual cost effectiveness for NO_X controls, and determined that these amounts ranged from approximately $1,400 to $3,000 (69 FR 4614—4615).

In the NPR, EPA proposed a two-phased annual NO_X control program, with a final phase in 2015 and a first phase in 2010. The regionwide emissions reduction requirements that EPA proposed—and the budget levels that would apply if all States chose to implement the reductions from EGUs—were based on using a combination of recent historical heat input and NO_X emissions rates for fossil fuel-fired EGUs. For historical heat input, EPA proposed determining the highest heat input from units affected by the Acid Rain Program for each affected State for the years 1999–2002. The EPA then summed this heat input for all of the States affected for annual NO_X reductions. For 2015, EPA calculated a proposed regionwide annual NO_X budget by multiplying this heat input by an emission rate of 0.125 lb/mmBtu, and for 2010 by multiplying by 0.15 lb/mmBtu.

In developing the CAIR NPR, when EPA considered the appropriate amount of annual SO_2 emissions reductions, EPA relied on the existing title IV annual SO_2 cap as a starting point. However, in considering the appropriate amount of NO_X reductions, the situation is different because title IV does not cap NO_X emissions. Therefore, EPA and the States have focused on emissions caps based on a combination of heat input and NO_X emission rates. Emission rates similar to the rates used to develop the CAIR NPR have been considered in the past. For example, the CAPI 1996 study, noted above, contemplated NO_X caps based on an emission rate of 0.15 lb/mmBtu (and other options based on NO_X rates of 0.20 lb/mmBtu and 0.25 lb/mmBtu). The NO_X SIP Call is based on an emission rate of 0.15 lb/mmBtu.

The methodology described in the NPR is best understood as the means for developing the target 2015 annual NO_X control level (or emissions budget) for further evaluation through IPM. The EPA developed this level mindful of its experience to date with the NO_X SIP Call and the earlier work EPA has performed on multi-pollutant power plant reduction programs. The EPA also considered available technical information on pollution controls, costs to industry and the general public, ambient air improvement, and consistency with the emerging $PM_{2.5}$ implementation program, in developing its target control level.

Recent advances in combustion control technology for NO_X reductions, as well as widespread use of selective catalytic reduction (SCR) on U.S. coal-fired EGU boilers achieving NO_X emission rates of 0.06 lb/mmBtu and below, provide evidence that even lower average NO_X emission rates are more highly cost-effective than rates considered in the past (based on analyzing EGUs), possibly on the order of 0.12 lb/mmBtu or less. The EPA developed the target annual NO_X control level (or emissions budget) with the understanding that the evaluation of that level might indicate that average emission rates on the order of 0.12 lb/mmBtu or less might be highly cost effective for the final (2015) control phase, and an interim level resulting in an average emission rate of less than 0.15 lb/mmBtu might be feasible for the first phase.

The EPA did evaluate the target annual NO_X control levels (or emissions budgets) using the IPM. The EPA confirmed that the 2015 level is highly cost effective. The Agency also evaluated the cost effectiveness of the proposed 2010 cap to assure that the interim phase reductions would also be highly cost effective. The EPA's IPM analyses for the CAIR includes all fossil fuel-fired EGUs with generating capacity greater than 25 MW.

The proposed cap for the first phase was developed taking into consideration how much pollution control for NO_X and SO_2 could be installed without running into a shortage of skilled labor, in particular boilermakers (EPA's assumptions regarding boilermaker labor are described in section IV.C.2 of this preamble). The Agency focused on providing substantial reductions of both SO_2 and NO_X emissions at the outset of the proposed program, leading to significant retrofits of Flue Gas Desulfurization units (FGD) for SO_2 control and SCR for NO_X control.

In the NPR, EPA explained that using the highest Acid Rain Program heat input for each State to develop a regionwide heat input amount, rather than the average Acid Rain Program heat input, provided a cushion that represented a reasonable adjustment to reflect that there are some non-Acid Rain units that operate in these States that will be subject to the proposed CAIR emission reduction levels. The EPA explained that it did not use heat input data from non-Acid Rain units in the proposal because it did not have all the necessary data available at the time the NPR was developed.[61] Using the highest of recent years' Acid Rain Program heat input provided an approximation of the regionwide heat input, although it did not include heat input from non-Acid Rain sources. Multiplying the approximate recent heat input by 0.125 lb/mmBtu to develop a proposed regionwide annual 2015 NO_X cap could reasonably be expected to yield an average effective NO_X emission rate (considering all EGUs potentially affected by CAIR for annual reductions, not only the Acid Rain units, and considering growth in heat input) somewhat less than 0.125 lb/mmBtu. Likewise, multiplying the approximate recent heat input by 0.15 lb/mmBtu to develop a regionwide annual 2010 NO_X cap could reasonably be expected to yield an average effective NO_X emission rate for all CAIR units of about 0.15 lb/mmBtu or less.

Although EPA calculated—in essence, as a target level for further evaluation—the proposed regionwide annual NO_X control levels (or emissions budgets) based on heat input from only Acid Rain Program units, the Agency evaluated the cost effectiveness of the control levels using heat input from all EGUs that potentially would be affected by the proposed CAIR. The EPA evaluated cost effectiveness using the IPM, which includes both Acid Rain units and non-Acid Rain units. Further, the IPM incorporates assumptions for electricity demand growth, and thus heat input growth.

Specifically, EPA evaluated these target annual NO_X caps on EGUs for 2010 and 2015—and therefore the associated regionwide emissions reductions—using the IPM, which, in effect, demonstrated that these proposed NO_X emissions cap levels can be met using highly cost-effective controls with the expected levels of electricity demand in 2010 and 2015, respectively. Those expected levels of electricity demand are higher than the electricity demand during the 1999 to 2002 years upon which EPA based heat input; and as a result, the amount of heat input necessary to meet the projected electricity demand is expected to be higher than the amount that EPA developed for evaluation purposes through the method described above. The projected average future emissions rates that would be associated with the 2010 and 2015 heat input levels needed to meet electricity demand (coupled with the NO_X emissions budgets developed through the methodology described above) would be about 0.14 lb/mmBtu and 0.11 lb/mmBtu in 2010 and 2015, respectively.[62] These average rates would be for all units affected by annual NO_X controls under CAIR, including non-Acid Rain units. Thus, the heat input is projected to be higher in 2010 and 2015 than the recent historic heat input used to develop the target emissions budgets, and the projected NO_X emission rates in 2010 and 2015 are lower than the 0.15 lb/mmBtu and 0.125 lb/mmBtu rates that were used to develop the budgets. IPM determined the costs of meeting these average future NO_X emission rates of 0.14 lb/mmBtu and 0.11 lb/mmBtu. The EPA considers these emission rates to be highly cost-effective and feasible.

In the NPR, EPA proposed an interim (Phase I) annual NO_X phase in 2010 and a final (Phase II) annual NO_X phase in 2015. However, in today's final rule, EPA is promulgating a Phase I for NO_X in 2009 (with the Phase II for NO_X in 2015, as proposed). The EPA determined the regionwide NO_X control levels for 2009 and 2015 for today's final action using the same methodology as we used to determine proposed levels. The Agency evaluated the cost effectiveness of the final reduction requirements (and average NO_X emission rates) using IPM and determined them to be highly cost-effective, assuming controls on EGUs. The EPA's evaluation of the cost effectiveness of the emission reduction strategy we assumed in establishing the final CAIR control levels is discussed further below.

The average NO_X emission rates in the first and second phases of CAIR will be lower than the nominal emission rate on which the NO_X SIP Call was based, which was 0.15 lb/mmBtu. In the NO_X SIP Call, EPA also considered a control level based on a lower nominal emission rate, 0.12 lb/mmBtu. However, at that time the use of SCR was not sufficiently widespread to allow EPA to conclude that the controls necessary to meet a tighter cap could be installed in the required timeframe, without causing reliability problems for the electric power sector. Now, through the experience gained from the NO_X SIP Call, EPA has confidence that with SCR technology average emissions rates lower than the NO_X SIP Call nominal emission rate can be achieved on a regionwide basis.

In the CAIR NPR, after determining the regionwide control level and evaluating it to assure that it is highly cost-effective, the Agency then apportioned the regionwide budgets to the affected States. The EPA proposed to apportion regionwide NO_X budgets to individual States on the basis of each State's share of recent average heat input. In the NPR, EPA used the average share of Acid Rain Program heat input. However, as discussed in the SNPR and the NODA, in order to distribute more equitably to States their share of the regionwide NO_X budgets, EPA then

[61] The EPA does not collect annual heat input data from these non-Acid Rain units. EIA does collect heat input from such units, however there are some limitations to the data. First, there are no requirements specifying how the data should be collected or quality assured. Second, the data is collected on a plant-wide basis rather than on a unit-by-unit basis.

[62] These projected average NO_X emissions rates are from updated IPM modeling done in 2004. The IPM modeling done prior to the NPR also projected similar average emission rates, about 0.15 lb/mmBtu and 0.11 lb/mmBtu in 2010 and 2015, respectively.

considered each State's proportional share of recent average heat input using data from non-Acid Rain Program sources as well as Acid Rain Program sources. The EPA obtained EIA heat input data reported for non-Acid Rain sources and combined the EIA heat inputs with Acid Rain heat inputs to determine each State's share of combined average recent heat input.

The fact that EPA distributed the regionwide budget to individual States based on their proportional share of heat input from Acid Rain and non-Acid Rain units combined does not affect the determination of the regionwide budgets themselves. The regionwide budgets were determined to be highly cost-effective when tested for all units—both non-Acid Rain units as well as Acid Rain units—that would be affected by CAIR. (The EPA's method for apportioning regionwide NO_X budgets to States is discussed in more detail elsewhere in today's preamble. That discussion includes an explanation of the differences between the State budgets that were presented in the NPR, the SNPR, and the NODA. In addition, see the TSD entitled ''Regional and State SO_2 and NO_X Emissions Budgets.'')

In the NPR, EPA proposed that Connecticut contributed significantly to downwind ozone nonattainment, but not to $PM_{2.5}$ nonattainment. Thus, the Agency proposed that Connecticut would not be subject to an annual NO_X control requirement and was not included in the region proposed for annual controls. We proposed that Connecticut would be affected by an ozone season-only NO_X control level, and proposed to calculate Connecticut's ozone season control level in a parallel way to how the regionwide annual NO_X control levels were calculated. That is, EPA selected the highest of the same 4 years of (ozone season-only) heat input used for the regionwide budget calculation, and multiplied that heat input by the same NO_X emission rates used to calculate the regionwide control levels. Connecticut is the only State for which an ozone season budget was proposed.

The EPA used the same methodology for developing regionwide budgets for today's final rule as was proposed in the NPR. For the final CAIR, EPA found that 23 States and the District of Columbia contribute significantly to downwind $PM_{2.5}$ nonattainment and found that 25 States and the District of Columbia contribute significantly to downwind ozone nonattainment (section III in today's preamble describes the significance determinations). CAIR requires annual NO_X reductions in all States determined to contribute significantly to downwind $PM_{2.5}$ nonattainment, and requires ozone season NO_X reductions in all States determined to contribute significantly to downwind ozone nonattainment (many of the CAIR States are affected by both annual and ozone season NO_X reduction requirements). The final CAIR ozone season NO_X reductions are required in two phases, with Phase I commencing in 2009 and Phase II in 2015, the same years as the annual NO_X reduction requirements.

As described above, the Agency proposed ozone season NO_X reduction requirements for Connecticut, and did not propose separate ozone season reduction requirements in any other State. For today's final rule, EPA requires ozone season reductions in all States contributing significantly to downwind ozone nonattainment. The EPA determined regionwide ozone season NO_X control levels for the final CAIR using the same methodology as was used for the annual NO_X reduction requirements (which is the same method that was proposed for Connecticut's ozone season budget). That is, EPA determined the highest (ozone season) heat input from Acid Rain Program units for the years 1999–2002 for each State, then summed this heat input for all of the States affected for ozone season NO_X reductions. For the final 2015 control level, EPA calculated a regionwide ozone season NO_X budget by multiplying this heat input by an emission rate of 0.125 lb/mmBtu, and for 2009 by multiplying by 0.15 lb/mmBtu. The Agency evaluated the cost effectiveness of these ozone season NO_X control levels (and average NO_X emission rates) using IPM and determined them to be highly cost-effective, assuming controls on EGUs. The EPA's evaluation of the cost effectiveness of the final CAIR control requirements is discussed further below.

Based on EPA's analysis of proposed annual NO_X control levels, in the NPR the Agency presented average costs for annual NO_X control of $800 per ton and $700 per ton for 2010 and 2015, and marginal costs of $1,300 per ton and $1,500 per ton for 2010 and 2015. In the NPR, EPA also presented marginal costs of annual NO_X control from sensitivity analyses that used EIA assumptions for electricity growth and natural gas prices. Those marginal control costs were $1,300 per ton and $1,600 per ton for 2010 and 2015, respectively. The EPA also presented costs from a sensitivity model run that used EIA assumptions for electricity growth and natural gas price and higher SCR costs. These marginal control costs were $1,700 per ton and $2,200 per ton for 2010 and 2015, respectively.[63]

In the NPR, EPA also presented the average cost effectiveness for ozone season-only NO_X control of $1,000 per ton and $1,500 per ton for 2010 and 2015, respectively, and a marginal cost for ozone season-only control of $2,200 per ton and $2,600 per ton for 2010 and 2015. The EPA also presented average costs for the non-ozone season (remaining seven months of the year) control of $700 per ton and $500 per ton in 2010 and 2015, respectively. (As noted above, the capital costs of installing NO_X control equipment would be largely identical whether the equipment will be operated during the ozone season only or for the entire year. However, the amount of reductions would be less if the control equipment were operated only during the ozone season compared to annual operation.)

The EPA proposed the conclusion that these costs met the criteria for highly cost-effective emissions reductions for NO_X (69 FR 4613–4615).

As with SO_2, EPA also considered the cost effectiveness of alternative stringency levels for this regulatory proposal (examining changes in the marginal cost curve at varying levels of emission reductions).

ii. What Are the Most Significant Comments That EPA Received About Proposed NO_X Emission Reduction Requirements, and What Are EPA's Responses?

Some commenters expressed concern that EPA did not account for growth of heat input in calculating regionwide NO_X emissions budgets, noting that growth was used in the calculation of the regional budget for the NO_X SIP Call. Commenters suggest that, by not taking heat input growth into account, EPA developed regionwide budgets that are unduly stringent.

On the other hand, some commenters noted that they supported EPA's proposal to base regionwide budgets on historical heat input and did not want EPA to use growth projections for calculating regionwide NO_X emissions budgets. Some stated that using actual, historic heat input numbers would be more straightforward than using growth projections, and some pointed to complications with the growth projection methodologies used in the NO_X SIP Call.

The EPA recognizes that it employed a growth factor in the NO_X SIP Call.

[63] The control costs for this model sensitivity that were presented in the NPR were in error (69 FR 4615). The corrected costs from the sensitivity are as shown here.

There, EPA determined the amount of the regional emissions reductions and budgets by applying a growth factor to a historic heat input baseline. The DC Circuit, after first remanding that growth methodology for a better explanation, upheld it. *West Virginia* v. *EPA,* 362 F.3d 861 (DC Cir., 2004). See 67 FR 21 868 (May 1, 2002).

For CAIR, as described above, EPA developed a target level for the proposed NO_X regionwide cap based on recent historic heat input and assumed emission rates of 0.125 lb/mmBtu and 0.15 lb/mmBtu for 2015 and 2010, respectively. The EPA evaluated these target NO_X emissions levels using IPM, which indicated that those target caps—in conjunction with expected electricity demand for 2015 and 2010—would result from higher heat input levels and lower average emissions rates (about 0.11 lb/mmBtu and 0.14 lb/mmBtu for 2015 and 2010, respectively) than the amounts assumed in developing the target NO_X caps. Most importantly, IPM indicated the cost levels associated with those projected 2015 and 2010 average NO_X emission rates, and EPA has determined that those cost levels are highly cost-effective. For the final rule, EPA revised its analyses to reflect the 2009 initial NO_X control phase, and determined that the final CAIR requirements are highly cost-effective. The EPA's methodology, in which the CAIR emissions reductions are predicted to be cost-effective under conditions of projected electricity growth that, in turn, projects heat input growth, in effect accounts for heat input growth. Moreover, the amount of heat input growth is the amount determined by IPM, a state-of-the-art model of the electricity sector (detailed documentation for IPM is in the docket).

Some commenters suggested that EPA adjust the NO_X regionwide budget amounts to include heat input from non-Acid Rain units. For example, some suggested adding the non-Acid Rain unit heat input amounts that EPA used in apportioning regionwide NO_X budgets to the States, to the total regionwide heat inputs that EPA used to calculate regionwide NO_X budgets.

The regionwide budgets determined in the NPR were target levels developed as a starting point for further evaluation. The regionwide heat input amounts and NO_X emission rates used to develop target budget levels were inherently imprecise. As discussed above, IPM modeling indicates that the projected future heat input amounts (based on electricity growth) are greater than the recent historic regionwide amount used to develop the target budget levels, and the future average emission rates for all units affected by CAIR annual NO_X controls (including non-Acid Rain units) are less than the rates used to develop the target budget levels. IPM indicates that the target regionwide NO_X budget levels (and corresponding future average NO_X emission rates and heat input levels) are highly cost-effective for all CAIR units, including non-Acid Rain units. The EPA does not believe it is necessary to adjust the target regionwide budget levels to include the relatively small additional amount of heat input from non-Acid Rain units. The method the Agency used to develop target levels was not intended to be a precise methodology for determining the NO_X caps; rather, it was a reasonable method for selecting a target level to be evaluated further. Upon evaluation of the target level, EPA determined that it can be achieved using highly cost-effective controls for all affected EGUs, including non-Acid Rain units.

iii. Analysis of NO_X Emission Reduction Requirements for Today's Final Rule

(I) Reference Lists of Cost-Effective Controls

For today's action, EPA updated the reference list of controls included in the NPR of the average and marginal costs per ton of recent NO_X control actions. The EPA systematically developed a list of cost information from recent actions and proposed actions. The Agency sought cost information for actions taken by EPA, and examined the comments submitted after the NPR was published, to identify all available control cost information to provide the updated reference list for today's preamble. The updated reference list includes both average and marginal costs of control to which EPA compares the CAIR control costs, although the Agency has limited information on marginal costs of other programs.

The EPA's updated summary of average costs of annual NO_X controls are shown in Table IV–6. The results of this reexamination show that costs of recent actions are generally very similar to those identified in the NO_X SIP Call. The cost figures are presented in 1999 dollars.[64]

TABLE IV–6.—AVERAGE COSTS PER TON OF ANNUAL NO_X CONTROLS

NO_X control action	Average cost per ton
Marine Compression Ignition Engines	Up to $200 [2]
Off-highway Diesel Engine	$400–$700 [2]
Nonroad Diesel Engines and Fuel	$600 [1]
Marine Spark Ignition Engines	$1,200–$1,800 [2]
Tier 2 Vehicle Gasoline Sulfur	$1,300–$2,300 [2]
Revision of New Source Performance Standards for NO_X Emissions-EGUs	$1,700 [3]
2007 Highway Heavy Duty Diesel Standards	$1,600–$2,100 [2]
National Low Emission Vehicle	$1,900 [2]
Tier 1 Vehicle Standards	$2,100–$2,800 [2]
Revision of New Source Performance Standards for NO_X Emissions-Industrial Units	$2,200 [3]
On-board Diagnostics	$2,300 [2]
Texas NO_X Emission Reduction Grants FY 2002–2003	$300–$12,700 [4]
Best Available Retrofit Technology (BART) for Electric Power Sector	$800 [5]

[1] Control of Emissions of Air Pollution From Nonroad Diesel Engines and Fuel; Final Rule (69 FR 39131; June 29, 2004). The value in this table represents the long-term cost per ton of emissions reduced from the total fuel and engine program (cost per ton of emissions reduced in the year 2030). This value includes the cost for NO_X plus NMHC reductions. 1999$ per ton.

[2] Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements; Final Rule (66 FR 5102; January 18, 2001). The values shown for 2007 Highway HD Diesel Stds are discounted costs. Costs shown in this table include a VOC component. 1999$ per ton.

[64] The updated reference list includes estimated average NO_X control costs under BART. The BART rule has been proposed but not finalized (69 FR 25184; May 5, 2004).

[3] Proposed Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units; Proposed Revision to Reporting Requirements for Standards of Performance for New Fossil-Fuel Fired Steam Generating Units; Proposed Rule (62 FR 36953; July 9, 1997), Table 4 (the Agency's estimate of average control costs was unchanged for the NSPS revisions final rule, published September 5, 1998). In the CAIR NPR, we included a value from the range of NO_X controls for coal-fired EGUs from Table 2 in the proposed NSPS proposed rule (62 FR 36951). 1999$ per ton.

[4] Costs shown in this table are the range of project costs reported for projects that were FY 2002–2003 recipients of the TERP Emission Reductions Incentive Grants Program. These costs may not be in 1999 dollars. *(www.tnrcc.state.tx.us/oprd/sips/grants.html)*

[5] The EPA IPM modeling 2004 of the proposed BART for the electric power sector (69 FR 25184, May 5, 2004), available in the docket. The EPA modeled the Regional Haze Requirements as a source specific 0.2 lb/mmBtu NO_X emission rate limit. Estimated average costs based on this modeling are $800 per ton in 2015 and 2020. 1999$ per ton.

Table IV–7 presents modeled marginal costs for recent State annual NO_X rules.

TABLE IV–7.—MARGINAL COSTS PER TON OF REDUCTION, RECENT ANNUAL NO_X RULES

NOX control action	Marginal cost per ton
Texas Rules	$2,000–$19,600 [1]

[1] The EPA IPM base case modeling August 2004, available in the docket. 1999$ per ton. We modeled Senate Bill 7 and Ch. 117, which impose varying NO_X control requirements in different areas of the State; the range of marginal costs shown here reflects the range of requirements.

The EPA does not believe that it has sufficient information, for today's rulemaking, to treat controls on source categories other than certain EGUs as providing highly cost-effective emissions reductions. The CAA Section 110 permits States to choose the sources and source categories that will be controlled in order to meet applicable emission and air quality requirements. This means that some States may choose to meet their CAIR obligations by imposing control requirements on sources other than EGUs.

As examples of cost-effective actions that States can take in efforts to provide for attainment with the air quality standards, Table IV–8 presents estimated average costs for potential local mobile source NO_X control actions. The EPA received these cost data during the public comments on the NPR.

TABLE IV–8.—AVERAGE COSTS OF POTENTIAL LOCAL MOBILE SOURCE CONTROL ACTIONS TO REDUCE NO_X EMISSIONS

[$ per Ton] [1]

Source category	Average cost per ton
MWCOG Analysis: Mobile Source, Bicycle racks in DC	$9,000
MWCOG Analysis: Mobile Source, Telecommuting Centers	7,300
MWCOG Analysis: Mobile Source, Government Action Days (ozone action days)	5,000
MWCOG Analysis: Mobile Source, Permit Right Turn on Red	1,200
MWCOG Analysis: Mobile Source, Employer Outreach	3,500
MWCOG Analysis: Mobile Source, Mass Marketing Campaign	2,900
MWCOG Analysis: Mobile Source, Transit Prioritization	8,500

[1] Washington DC Metro Area MWCOG Analysis of Potential Reasonably Available Control Measures (RACM). Projects determined to be "Possible" by MWCOG but not RACM because benefits from the possible control measures do not meet the 8.8 tpd NO_X or 34.0 tpd VOC threshold necessary for RACM. These costs may not be in 1999 dollars. (www.mwcog.org/uploads/committee-documents/z1ZZXg20040217144350.pdf) Comments submitted to the EPA CAIR docket from the Clean Air Task Force *et al.*, dated March 30, 2004, included costs from the MWCOG analysis.

(II) Cost Effectiveness of CAIR Annual NO_X Reductions

Table IV–9 provides the average and marginal costs of annual NO_X reductions under CAIR for 2009 and 2015. These costs are updated from the NPR figures—the EPA analyzed the costs of the CAIR using an updated version of IPM (documentation for the IPM update is in the docket). Further, EPA modified the modeling to match the final CAIR strategy (see section IV.A.1 for a description of EPA's CAIR IPM modeling).

CAIR provides for a Compliance Supplement Pool (CSP) of NO_X allowances that can be used for compliance with the annual NO_X reduction requirements. The CSP is discussed in detail later in this preamble. The EPA used IPM to model marginal costs of CAIR with the CSP. The magnitude of the NO_X CSP is relatively small compared to the annual NO_X budget,[65] thus the CSP does not significantly impact the marginal costs (see Table IV–9).

As with SO_2 marginal costs, EPA considered the sensitivity of the NO_X marginal cost results to assumptions of higher electric growth and future natural gas prices than the Agency used in the base case, as shown in Table IV–9.

TABLE IV–9.—ESTIMATED COSTS PER TON OF ANNUAL NO_X CONTROLLED UNDER CAIR [1]

Type of cost effectiveness	2009	2015
Average Cost—Main Case	$500	$700
Marginal Cost—Main Case	1,300	1,600

[65] The CSP consists of 200,000 tons, which is apportioned to each of the 23 States and the District of Columbia that are required by CAIR to make annual NO_X reductions, as well as the 2 States (Delaware and New Jersey) for which EPA is proposing to require annual NO_X reductions.

TABLE IV–9.—ESTIMATED COSTS PER TON OF ANNUAL NO_X CONTROLLED UNDER CAIR [1]—Continued

Type of cost effectiveness	2009	2015
Marginal Cost—With Compliance Supplement Pool (CSP)	1,300	1,600
Sensitivity Analysis: Marginal Cost Using Alternate Electricity Growth and Natural Gas Price Assumptions	1,400	1,700

[1] The EPA IPM modeling 2004, available in the docket. 1999$ per ton.

These estimated NO_X control costs under CAIR reflect annual EGU NO_X caps of 1.5 million tons in 2009 and 1.3 million tons in 2015 within the CAIR annual NO_X control region (the 23 States and DC that must make annual reductions). In both the main IPM modeling case and the modeling case that includes the CSP, projected annual NO_X emissions in the CAIR region will be about 1.5 million tons in 2009 and 1.3 million tons in 2015. The projected emissions are very similar in both modeling cases because the CSP is relatively small compared to the annual NO_X budget.

Average costs shown for 2015 are based on the amount of reductions that would achieve the total difference in projected emissions between the base case conditions and CAIR in the year 2015. These costs are not based on the increment in reductions between 2009 and 2015. (A more detailed description of the final CAIR SO_2 and NO_X control requirements is provided later in today's preamble.)

Most of the States subject to today's $PM_{2.5}$ control requirements have been subject to the NO_X SIP Call requirements. Some sources in these States have installed SCRs, and run them during the ozone season. These sources might comply with the $PM_{2.5}$ annual NO_X requirements by, at least in part, running the SCR controls for the remaining months of the year. Under these circumstances, the compliance costs for the $PM_{2.5}$ SIP requirements are lower.

Table IV–10 provides estimated costs per ton of NO_X for non-ozone season reductions under CAIR. These figures are updated from the NPR calculations—the EPA analyzed the costs of the CAIR using an updated version of IPM (documentation for the IPM update is in the docket) and modeled controls on a region that more closely matches the region affected by CAIR.

TABLE IV–10.—PREDICTED COSTS PER TON OF NON-OZONE SEASON NO_X CONTROLLED UNDER CAIR [1]

Type of cost effectiveness	2009	2015
Average Cost	$500	$500

[1] The EPA IPM modeling 2004, available in the docket. 1999$ per ton.

The estimated non-ozone season NO_X costs, like the annual NO_X costs, are on the low end of the cost effectiveness range described in Table IV–6. The EPA considers the 2015 and also the 2009 costs to represent highly cost-effective controls.

Environmental Defense reached similar conclusions regarding the cost effectiveness of non-ozone season NO_X reductions, as described in their report ''A Plan for All Seasons: Costs and Benefits of Year-Round NO_X Reductions in Eastern States (2002).'' As stated in that report, ''[As Figure 4 shows,] extending NO_X reductions throughout the year results in dramatic decreases in the per-ton costs of NO_X emission reductions for the 19 NO_X SIP Call States. This is because the bulk of the cost for reducing NO_X emissions from power plants lies in the capital investment in the control equipment. Once the primary investment has been made, it costs relatively little to continue running the control equipment beyond the summer months required by EPA's NO_X SIP Call.'' Environmental Defense based these conclusions on analysis conducted by Resources for the Future (RFF). In an RFF paper, ''Cost-Effective Reduction of NO_X Emissions from Electricity Generation (July 2001),'' RFF draws similar conclusions.

(III) NO_X Cost Comparison for CAIR Requirements

The EPA believes that selecting as highly cost-effective amounts at the lower end of these average and marginal cost ranges is appropriate for reasons explained above in this section of the preamble.

As discussed above, although in the NO_X SIP Call the cost level selected was not at the low end of the reference range of costs, if the NO_X SIP Call costs were for annual rather than seasonal controls they would have been lower relative to the other control costs on the reference list which were mostly for annual programs.

For annual NO_X, the range of average cost effectiveness extends broadly, from under $200 to thousands of dollars (Table IV–6). The 2015 estimated average costs for CAIR annual NO_X control of $700 are consistent with the lower end of this range.

Less information is available for the marginal costs of controls than for average costs. Looking at the available marginal costs (Table IV–7), the 2015 CAIR marginal costs for annual NO_X controls are at the lower end of the range. The EPA also evaluated the cost effectiveness of the 2009 cap, and concluded that the 2009 requirements are highly cost-effective.

(IV) Cost Effectiveness: Marginal Cost Curves for Annual NO_X Control

As with SO_2 controls, EPA also considered the cost effectiveness of alternative stringency levels for NO_X control for today's action by examining changes in the marginal cost curve at varying levels of emissions reductions. Figure IV–3 shows that the ''knee'' in the 2010 marginal cost effectiveness curve for EGUs—the point where the cost of controlling a ton of NO_X begins to increase at a noticeably higher rate—appears to occur at over $1,700 per ton of NO_X. Although EPA conducted this marginal cost curve analysis based on an initial NO_X control phase in 2010, the results would be very similar for 2009, which is the initial NO_X phase in the final CAIR. Figure IV–4 shows that the ''knee'' in the 2015 marginal cost effectiveness curve for EGUs appears to occur at over $1,700 per ton of NO_X. (The EPA based these marginal NO_X cost effectiveness curves on the electricity growth and natural gas price assumptions in the main CAIR IPM modeling run. Marginal cost effectiveness curves based on other electric growth and natural gas price assumptions would look different, therefore it would not be appropriate to compare the curves here to the marginal costs based on the IPM modeling sensitivity run that used EIA assumptions.) The EPA used the Technology Retrofitting Updating Model (TRUM), a spreadsheet model based on IPM, for this analysis. These results make clear that this rule is very cost-effective because the control level is below the point at which the cost begins to increase at a significantly higher rate.

In this manner, these results corroborate EPA's findings above concerning the cost effectiveness of the emissions reductions.[66]

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Figure IV-3

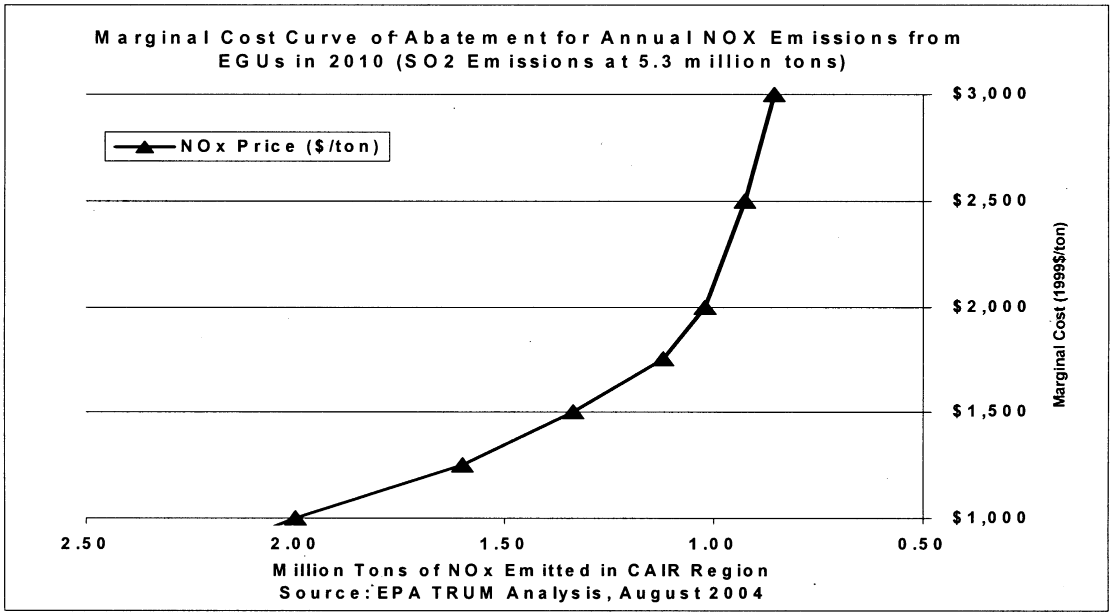
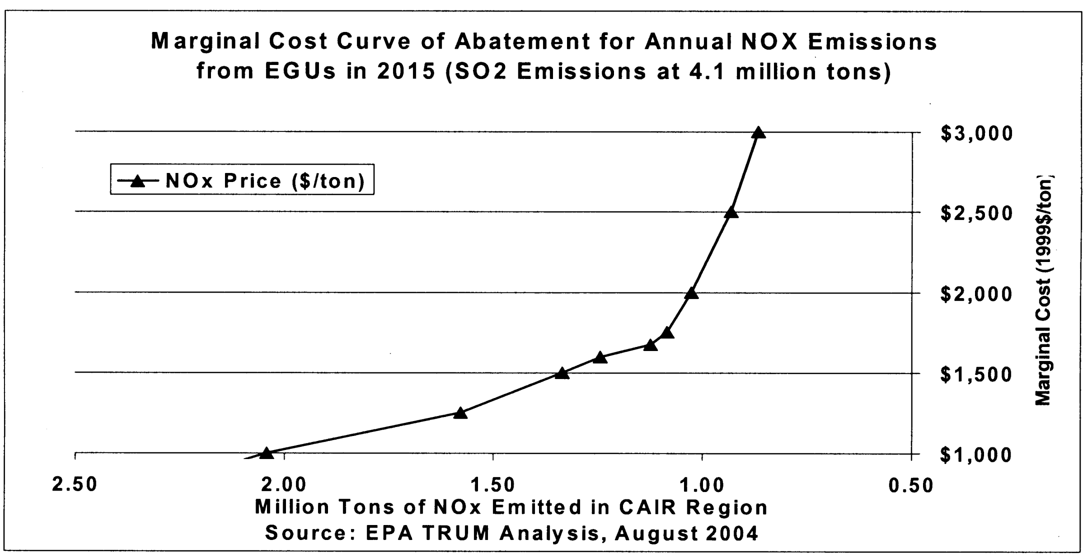


Figure IV-4



[66] EPA is using the knee in the curve analysis solely to show that the required emissions reductions are very cost effective. The marginal cost curve reflects only emissions reduction and cost information, and not other considerations. We note that it might be reasonable in a particular regulatory action to require emissions reductions past the knee of the curve to reduce overall costs of meeting the NAAQS or to achieve benefits that exceed costs. As in the case of SO_2 controls, described above, it should be noted that similar analysis for other source categories may yield different curves.

(V) Cost Effectiveness of Ozone Season NO_X Reductions

The CAIR requires ozone season NO_X emissions reduction for all States determined to contribute significantly to ozone nonattainment downwind (25 States and the District of Columbia). The EPA used IPM to model average and marginal costs of the ozone season reductions assuming EGU controls. In this modeling case, EPA modeled an ozone season NO_X cap for the region affected by CAIR for downwind ozone nonattainment, but did not include the CAIR annual SO_2 or NO_X caps. Based on that modeling, Table IV–11 provides estimated average and marginal costs of regionwide ozone season NO_X reductions for 2009 and 2015. Table IV–11 shows the estimated cost effectiveness of today's ozone season NO_X control requirements for 8-hour transport SIPs.

TABLE IV–11.—ESTIMATED COSTS PER TON OF OZONE SEASON NO_X CONTROLLED UNDER CAIR [1]

Type of cost effectiveness	2009	2015
Average Cost	$900	$1,800
Marginal Cost	2,400	3,000

[1] The EPA IPM modeling 2004, available in the docket. 1999$ per ton.

These estimated NO_X control costs are based on ozone season EGU NO_X caps of 0.6 million tons in 2009 and 0.5 million tons in 2015 within the CAIR ozone season NO_X control region. Average costs shown for 2015 are based on the amount of reductions that would achieve the total difference in projected emissions between the base case conditions and CAIR in the year 2015. These costs are not based on the increment in reductions between 2009 and 2015. (A more detailed description of the final CAIR SO_2 and NO_X control requirements is provided later in today's preamble.)

The EPA believes that selecting as highly cost-effective amounts at the lower end of the average and marginal cost ranges is appropriate for reasons explained above in section IV in this preamble.

In the NO_X SIP Call, EPA identified average costs of $2,500 (1999$) (or $2,000 (1990$)) as highly cost-effective.[67] The estimated average costs of regionwide ozone season NO_X control under CAIR are $1,800 per ton in 2015 and $900 per ton in 2009. Thus, with respect to average costs the controls for the final phase (2015) cap, which are below the $2,500 identified in the NO_X SIP Call, are also highly cost-effective, as are those for the 2009 cap. In addition, the estimated average costs of CAIR ozone season NO_X control are at the lower end of the reference range of average annual NO_X control costs (the reference list of average annual NO_X control costs is presented above).

Similarly, the estimated marginal costs[68] of ozone season CAIR NO_X controls are within EPA's reference range of marginal costs, at the lower end of the range (the reference list of marginal annual NO_X control costs is presented above). We note that the marginal costs in the reference range are for annual NO_X reductions, and would likely be higher for ozone season only programs. Considering both average and marginal costs, the CAIR ozone season control level is highly cost-effective.

For purposes of estimating costs of ozone season control under CAIR, EPA set up this modeling case with CAIR ozone season NO_X requirements but without the annual NO_X requirements. The Agency believes that the cost of the ozone season CAIR requirements will actually be lower than the costs presented here because interactions will occur between the CAIR annual and ozone season NO_X control requirements.[69] In addition, for States in both programs, the same controls achieving annual reductions for PM purposes will achieve ozone season reductions for ozone purposes; this is not reflected in our cost-per-ton estimates.

As with SO_2 controls, and annual NO_X controls, EPA also considered the cost effectiveness of alternative stringency levels for CAIR NO_X reductions for ozone purposes by examining changes in the marginal cost curve at varying levels of emissions reductions. Figure IV–5 shows that the ''knee'' in the 2010 marginal cost effectiveness curve for ozone season NO_X reductions from EGUs—the point where the cost of controlling an ozone season ton of NO_X begins to increase at a noticeably higher rate—appears to occur somewhere between $3,000 and $4,000 per ton of NO_X. Although EPA conducted this marginal cost curve analysis based on an initial NO_X control phase in 2010 the results would be very similar for 2009, which is the initial NO_X phase in the final CAIR. Figure IV–6 shows that the ''knee'' in the 2015 marginal cost effectiveness curve for ozone season NO_X reductions from EGUs appears to occur somewhere between $3,000 and $4,000 per ton of NO_X. The EPA used the Technology Retrofitting Updating Model (TRUM), a spreadsheet model based on the IPM, for this analysis. These results make clear that CAIR NO_X reductions for ozone purposes are very cost-effective because the control level is below the point at which the cost begins to increase at a significantly higher rate.

In this manner, these results corroborate EPA's findings above concerning the cost effectiveness of the emissions reductions.[70]

[67] For both the NO_X SIP Call and CAIR, the NO_X control costs on the reference lists are generally for annual reductions. The EPA compared the costs of ozone season reductions under the NO_X SIP Call, as well as ozone season CAIR NO_X reductions, to the annual reduction programs on the reference lists.

[68] In the NO_X SIP Call EPA used average, not marginal, costs to evaluate cost effectiveness. For the reasons discussed above we are evaluating both average and marginal costs for CAIR.

[69] Estimated costs for regionwide CAIR NO_X controls during the ozone season are higher than the average and marginal costs for CAIR annual NO_X controls. This is because, as noted above, the capital costs of installing NO_X control equipment would be largely identical whether the SCR will be operated during the ozone season only or for the entire year. However, the amount of reductions would be less if the control equipment were operated only during the ozone season compared to annual operation.

[70] EPA is using the knee in the curve analysis solely to show that the required emissions reductions are very cost effective. The marginal cost curve reflects only emissions reduction and cost information, and not other considerations. We note that it might be reasonable in a particular regulatory action to require emissions reductions past the knee of the curve to reduce overall costs of meeting the NAAQS or to achieve benefits that exceed costs. As in the case of SO_2 controls, described above, it should be noted that similar analysis for other source categories may yield different curves.

Figure IV-5

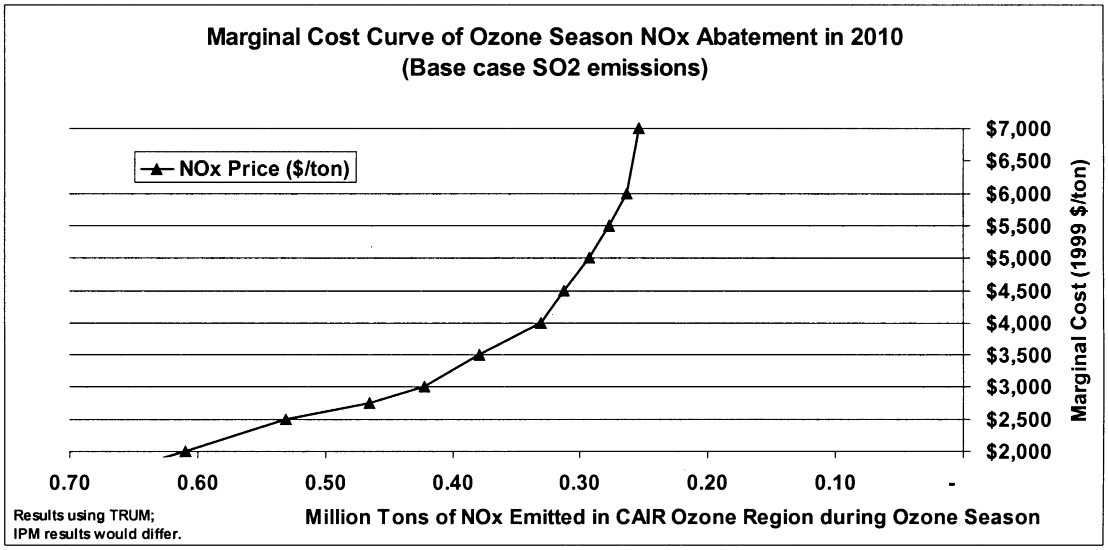
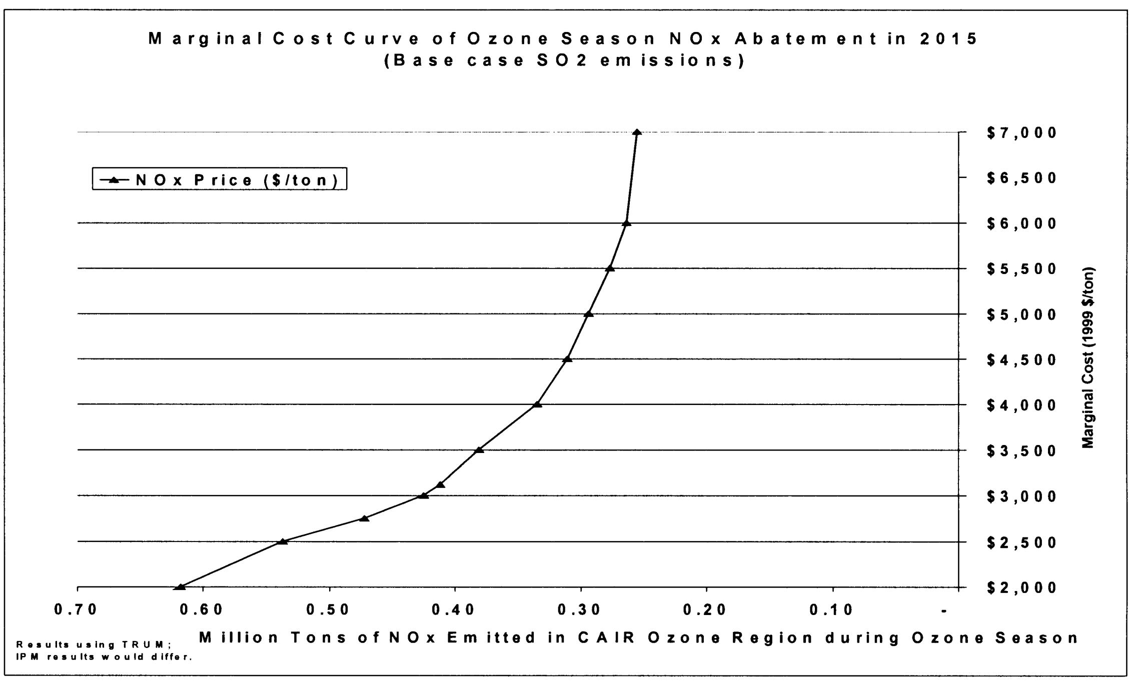


Figure IV-6



B. What Other Sources Did EPA Consider When Determining Emission Reduction Requirements?

1. Potential Sources of Highly Cost-Effective Emissions Reductions

In today's rulemaking, EPA determines the amount of regionwide emissions reductions required by determining the amount of emissions reductions that could be achieved through the application of highly cost-effective controls on certain EGUs. The EPA has reviewed other source categories, but concludes that for purposes of today's rulemaking, there is insufficient information to conclude that highly cost-effective controls are available for other source categories.

a. Mobile and Area Sources

In the NPR (69 FR 4610), EPA explained that ''it did not identify highly cost-effective controls on mobile or area sources.'' No comments were received suggesting that mobile or area sources should be controlled. Therefore, in developing emission reduction requirements, EPA is not assuming any emissions reductions from mobile or area sources.

b. Non-EGU Boilers and Turbines

The largest single category of stationary source non-EGUs are large non-EGU boilers and turbines. This source category emits both SO_2 and NO_X. In the CAIR NPR, EPA proposed not to include any potential SO_2 or NO_X emissions reductions from non-EGU boilers and turbines as constituting ''highly cost-effective'' reductions and thus to be taken into account in establishing emissions requirements because EPA believed it had insufficient information on their control costs, particularly costs associated with the integration of NO_X and SO_2 controls. In addition, based on information EPA does have, projected base case (without the CAIR) emissions of SO_2 and NO_X from these sources are significantly lower than projected EGU emissions. The EPA projects that in 2010 under base case conditions, EGUs would contribute 70 percent of SO_2 in the CAIR region compared to 15 percent from non-EGU boilers and turbines in the CAIR region. The Agency also predicts that in 2010 under the base case, EGUs would contribute 25 percent of NO_X emissions in the CAIR region compared to 16 percent from non-EGU boilers and turbines in the CAIR region. Thus, simply on an absolute basis, non-EGU emissions are relatively less significant than emissions from EGUs. The EPA is finalizing its proposed approach to these sources and has not based today's requirements on any presumed availability of highly cost-effective emissions reductions from non-EGU boilers and turbines.

A number of commenters believe EPA should determine that emissions reductions from non-EGUs should be taken into account in establishing emission requirements because, they believe, highly cost-effective controls are available for these sources. These commenters argued that highly cost-effective controls are available for these sources and that EPA should have sufficient emissions and control cost information because the same sources were included in the NO_X SIP Call.

In addition, while it is true that these sources were included in the NO_X SIP Call, EPA only addressed NO_X reductions from these sources. Neither SO_2 reductions nor monitoring of SO_2 emissions is required by the NO_X SIP Call. As a result, for these sources, EPA has less reliable SO_2 emissions data and very little information on the integration of NO_X and SO_2 controls. Although EPA has more information on NO_X emissions from these sources because of the NO_X SIP Call (and other programs in the northeastern U.S.), the geographic coverage of the CAIR includes some States that were not included in the NO_X SIP Call, some of which States contain significant amounts of industry. The EPA has even less emissions data from non-EGUs in these non-SIP call States affected by the CAIR. While EPA has incorporated State-submitted emissions inventory data for 1999 into its analysis for the CAIR, even this data is generally lacking information on fuel, sulfur content, and existing controls. Without this data, it is very difficult to assess the emission reduction opportunities available for non-EGU boilers and turbines. Furthermore, with regards to NO_X, many non-EGU boilers and turbines are making reductions using low NO_X burners (the control technology EPA assumed in making the cost-effectiveness determinations in the NO_X SIP Call). Since these controls are operated year-round, annual emissions reductions are already being obtained from many of these units. Additional reductions would likely be less cost effective.

Another commenter stated that non-EGU ''major sources'' are subject to the requirements of title V of the CAA and, therefore, EPA should have adequate emissions data provided as part of the sources' permitting obligations. However, title V simply requires that a source's permit include the substantive requirements (such as emission monitoring requirements) imposed by other sections of the CAA and does not itself impose any substantive requirements. Thus, the mere fact that a source is a major source required to have a title V permit does not mean that the source is monitoring and submitting emissions, fuel, and control device data. Many such sources do not, in fact, provide such data.

One commenter submitted cost information for FGD technology applications on industrial boilers. However, the information submitted by the commenter was based on the use of a limited number of technologies and for a limited number of boiler sizes. The EPA does not believe that the limited information demonstrates that SO_2 emissions from these sources could be controlled in a highly cost-effective manner across the entire sector in question, or to what level the emissions could be controlled.

Some commenters recommended including non-EGU boilers and turbines because in the future, after reductions from EGUs are made, the relative contribution of non-EGU boilers and turbines to the total NO_X and SO_2 emissions will increase. The EPA agrees that the relative contribution of non-EGUs to total NO_X and SO_2 emissions will increase in the future if States choose to meet their CAIR emissions reduction obligations solely by way of emission reductions made by EGUs. However, EPA does not believe that this, by itself, provides any basis for determining that in the context of this rule emissions reductions from non-EGUs should be determined to be highly cost-effective. As discussed above, EPA believes it is necessary to have more reliable emissions data and better control cost information for these sources before assuming reductions from them in the CAIR. The EPA is working to improve its inventory of emissions and control cost information for non-EGU boilers and turbines. Specifically, we are assessing the emission inventory submittals for 2002 made by States in response to the relatively new requirements of 40 CFR part 51 (the Consolidated Emission Reporting Rule), and we will work with States whose submissions appear to have gaps in required data. We also note that EPA provides financial and technical support for the efforts of the five Regional Planning Organizations to coordinate among and assist States in improving emission inventories.

Another commenter expressed concern that if the decision whether to control large industrial boilers is left to the States, the result may be inequitable treatment of EGUs on a State-by-State basis, particularly with respect to allowances, and therefore it would make sense to require NO_X and SO_2 reductions from large industrial boilers. Section 110 of the CAA leaves the ultimate choice of what sources to control to the States, and EPA cannot require States to control non-EGUs. Even if EPA had included reductions from non-EGUs in determining the total amount of reductions required under the CAIR, EPA could not have required any State to achieve those reductions through emission limitations on non-EGUs.

The recent economic circumstances faced by the manufacturing sector accentuates EPA's concerns about the lack of reliable emissions data and control information regarding non-EGUs. We note that the U.S. manufacturing sector was adversely affected by the latest business cycle slowdown. As noted in the 2004 Economic Report of the President, the manufacturing sector was hit earlier, longer, and harder than other sectors of the economy. The 2004 Report also points out that, although manufacturing output has dropped much more than the real gross domestic product (GDP) during past business cycles, the latest recovery has been unusual because it has been weaker for the manufacturing sector than the recovery in the real GDP. The disparity across sectors (and even within individual sectors) in the economic condition of firms reinforces

EPA's concerns about moving forward to consider emission controls on non-EGUs at this time.

As explained elsewhere in this preamble, although the CAIR does not require that States achieve the required emissions reductions by controlling particular source categories, we expect that States will meet their CAIR obligations by requiring emissions reductions from EGUs because such reductions are highly cost effective. We believe the States are in the best position to make decisions regarding any additional control requirements for non-EGU sources. In making such decisions, States may take into consideration all relevant factors and information, such as differences across States in the need for control, differences in relative contribution of various sources, and differences in the operating and economic conditions across sources.

c. Other Non-EGU Stationary Sources

In the NPR and in the technical support document entitled ''Identification and Discussion of Sources of Regional Point Source NO_X and SO_2 Emissions Other Than EGUs (January 2004),'' EPA applied a similar rationale for non-EGU stationary sources other than boilers and turbines. For SO_2, EPA noted that the emissions from such sources were a relatively small part of the emissions inventory, and we also noted the lack of information on costs. For NO_X, we explained that more information was available than for SO_2. This is because the NO_X SIP Call included consideration of emissions control measures for internal combustion (IC) engines and cement kilns, and developed cost estimates for other NO_X-emitting categories such as process heaters and glass manufacturing. However, we believed—as for boilers and turbines, discussed above—that insufficient information on emission control options and costs, was available to apply these measures to the entire geographic area covered by the proposed rule.

No adverse comments were received suggesting inclusion of SO_2 emissions reductions from non-EGU stationary sources other than boilers and turbines. Accordingly, EPA has determined not to consider SO_2 reductions from these other non-EGU stationary sources.

Several commenters suggested that EPA should have been able to consider NO_X emissions reductions from non-EGU categories other than boilers and turbines, such as internal combustion (IC) engines and refinery fluid catalytic cracking units. These commenters believed such reductions were demonstrated to be cost effective, and questioned EPA's assertion that insufficient information is available. Finally, some commenters believe EPA should have, at a minimum, required that controls for NO_X SIP Call sources—including large IC engines and cement kilns—should be extended from the ozone season to the entire year.

We believe it likely that inclusion in today's requirements of reductions from any highly cost-effective controls—if available—for these categories would have very small effects. First, most of the States included in the CAIR rule were also included in the NO_X SIP Call, so that many of the emissions reductions that would be available from these sources have already occurred due to implementation of the NO_X SIP Call. Second, in the States included in the CAIR rule, but which were not covered by the NO_X SIP Call, only a small portion of NO_X emissions come from cement kilns and IC engines compared to EGUs. Moreover, in some parts of this geographic area, in particular for Texas, many sources in these source categories are already regulated under ozone nonattainment plans (including SIPs for the Texas cities of Houston, Galveston, and Dallas).

Regarding the commenters' recommendation that extending NO_X SIP Call control requirements to a year-round basis for large IC engines and cement kilns should be considered to be highly cost effective, EPA believes that few emissions reductions would be achieved from doing so. The types of controls that were applied in the NO_X SIP Call States, while required to be in place only during the ozone season, will, as a practical matter, be applied on a year-round basis, whether or not so required by today's rule. Most, if not all, of the NO_X SIP Call States have developed regulations to control NO_X emissions from IC engines and cement kilns during the ozone season. The control of choice to meet these reductions from large lean burn IC engines is low emission combustion (LEC), which for retrofit applications is a substantial equipment modification of the engine's combustion system. The engine will operate with LEC year round because this modification is a permanent change to the engine. Most, if not all, new large lean-burn IC engines have LEC. In addition, year-round emissions controls are already required for rich-burn engines greater than 500 hp which will likely install nonselective catalyst reduction to comply with the recently adopted hazardous air pollutant standards (see final rule for reciprocating IC engines, 69 FR 33474, June 15, 2004). For cement kilns, the controls of choice are low NO_X burners and mid-kiln firing. Low NO_X burners (LNB) are a permanent part of the kiln, so that the kiln will operate year-round with LNB. Mid-kiln firing is a kiln modification for which a solid and slow burning fuel (typically tires) is injected in the mid-kiln area. Due to tipping fees and fuel credits, mid-kiln firing results in an operating cost savings. After this system is installed, year-round operation is expected.

C. Schedule for Implementing SO_2 and NO_X Emissions Reduction Requirements for $PM_{2.5}$ and Ozone

1. Overview

In the NPR, EPA proposed a two-phased schedule for implementing the CAIR annual emission reduction requirements: implementation of the first phase would be required by January 1, 2010 (covering 2010–2014), and that for the second phase by January 1, 2015 (covering after 2014). The EPA based its proposal on its analysis of engineering, financial, and other factors that affect the timing for installing the emission controls that would be most cost-effective—and are therefore the most likely to be adopted—for States to meet the CAIR requirements. Those air pollution controls are primarily retrofitted FGD systems (i.e., scrubbers) for SO_2 and SCR systems for NO_X on coal-fired power plants.

The EPA's projections showed a significant number of affected sources installing these controls. The proposed two-phased schedule allowed the implementation of as much of the controls as feasible by an early date, with a later time for the remaining controls.

The EPA received detailed, technical comments from commenters who argued that the controls could not be implemented until later than proposed, and from other commenters who argued that the controls could be implemented sooner than proposed. The EPA has reviewed the comments and has conducted additional research and analyses to verify availability of adequate industrial resources, including boilermakers, for constructing the emission control retrofits required by CAIR. These analyses are based on conservative assumptions, including those suggested by the commenters, to ensure that the requirements imposed by CAIR do not result in shortages of the required resources that could substantially increase construction costs for pollution controls and reduce the cost effectiveness of this program.

Today, EPA is taking final action to require the annual emissions reductions on the same two-phase schedule as proposed. However, the requirements for the first phase include two separate compliance deadlines: Implementation of NO_X reductions are required by January 1, 2009 (covering 2009–2014) and for SO_2 reductions by January 1, 2010 (covering 2010–2014). The compliance deadline requirements for the second phase are the same as proposed. The EPA believes that its action is consistent with the Agency's obligations under the CAA to require emission reductions for obtaining NAAQS to be achieved as soon as practicable. The EPA applied the same criterion in implementing the NO_X SIP Call, which was based on a single-phased schedule.[71]

2. Engineering Factors Affecting Timing for Control Retrofits

a. NPR

In the NPR, EPA identified the availability of boilermakers as an important constraint for the installation of significant amounts of SCR and FGD retrofits. Boilermakers are skilled laborers that perform various specialized construction activities, including welding and rigging, for boilers and high pressure vessels. The air pollution control devices, such as scrubber and SCR vessels, require boilermakers for their construction. Apprentices with no prior work-related experience complete a four-year training program, to become full boilermakers. For apprentices with relevant experience, this training period could be shorter. For example, union members representing the shipbuilding trade could be expedited into the boilermaker division within a year.

The boilermaker constraint was considered more important for the initiation of the first phase of CAIR, since the NO_X SIP Call experience had shown that many sources would be adverse to committing significant funds to install controls until after SIPs were finalized. With the States required to finalize SIPs in 18 months after the signing of the final rule, the sources would have three years in which to complete purchasing, construction, and startup activities associated with these controls, to meet the proposed CAIR deadline.

The EPA's projections showed power plants installing 51.4 gigawatts (GW) of FGD and 28.2 GW of SCR retrofits during the first CAIR phase. These projections include retrofits for CAIR as well as retrofits for base case policies (i.e., retrofits for existing regulatory requirements). We estimated the total boilermaker-years required for installing these controls at 12,700, which was based on the boilermakers being utilized over a period of 18 months during the installation process. Also, based on the projected boilermaker population in the timeframe relevant to the installation of these controls, we estimated that 14,700 boilermaker-years were available over the same 18-month period. The availability of approximately 15 percent more boilermaker-years than required, as shown by these estimates, confirms the adequacy of this critical resource for CAIR and EPA assumed this to be a reasonable contingency factor.

The EPA also determined that installation of the projected amounts of FGD and SCR retrofits could be completed within the three-year period available for CAIR. This determination was based on a previous report prepared by EPA for the proposed Clear Skies Act, ''Engineering and Economic Factors Affecting the Installation of Control Technologies for Multi-Pollutant Strategies,'' (docket no. OAR–2003–0053–0106). According to this report, an average of 21 months are required to install SCR on one unit, and 27 months to install a scrubber on one unit. For multiple units within the same plant, installation of controls would normally be staggered to avoid operational disruptions. The EPA projected that the maximum number of multiple-unit controls required for each affected facility could all be installed within three years.The NPR proposal included a second phase, with a compliance deadline of January 1, 2015. The EPA's projections showed power plants installing 19.1 GW of FGD and 31.7 GW of SCR retrofits by 2015, which included retrofits for CAIR as well as retrofits for base case policies (i.e., retrofits for existing regulatory requirements). Availability of boilermaker labor was not an important constraint for this phase.

b. Comments

The EPA received several comments relating to the requirements for the two-phased implementation program, the emission caps and compliance deadline for each phase, and resources required to install necessary controls. The commenters offered opposing viewpoints, which can be broadly categorized as follows.

Several commenters indicated that the compliance deadline of 2010 for the first phase was not attainable and argued that EPA should either extend the deadline, or set higher emission caps for this phase. The commenters raised the following specific points in support of their concerns:

- The time allowed for completing various activities from planning to startup of the required controls was not sufficient. Other related activities, including project financing and obtaining a landfill permit for the scrubber waste, could also require more time than what the rule allowed. In addition, the short implementation period would require simultaneous outages of too many units to tie the new equipment into the existing systems, which would affect the reliability of the electrical grid.
- Implementation of controls to the required large number of units would cause shortages in the supply of critical industrial resources, especially boilermakers. An analysis performed by a commenter showed a shortfall in the supply of boilermaker labor during the construction period relevant to CAIR retrofits. This commenter anticipated that certain key variables would be greater in value than those used by EPA and based their analysis on higher SCR prices, EIA-projected higher natural gas prices and electricity demand factors, and more stringent boilermaker duty rates (boilermaker-year/MW) and availability factors.

Commenters who favored more stringent compliance deadlines argued that the required controls could be installed in less time and more controls could be built in early years. These commenters raised the following specific points in support of their concerns.

- The compliance deadlines for the two phases did not support the ozone and fine particulate ($PM_{2.5}$) attainment dates mandated by the CAA. The Phase I deadline should be accelerated to meet these attainment dates. Sufficient industrial resources, including boilermakers, would be available to support such an acceleration. While some commenters supported an earlier Phase I deadline of January 1, 2008, the others supported a deadline of January 1, 2009. Some of these commenters also suggested that the Phase I deadline be accelerated only for NO_X.
- The EPA's estimates for the boilermaker availability were too conservative. A boilermaker labor analysis performed by one commenter showed an adequate supply of this resource to support installation of all Phase I and II controls by the start of the first phase (by 2010), thereby eliminating the need for two phases.
- The time allowed for installing controls for Phase II was excessive. The initiation of this phase could be moved forward.

[71] The NO_X SIP Call Rule allowed approximately 3½ years for implementation of all NO_X Controls.

Several commenters supported EPA's assumptions used in support of the adequacy of the implementation period and resources to build the required CAIR controls. These assumptions included the overall construction schedule durations for SCR and FGD systems and boilermaker unit rates.

c. Responses

The EPA reviewed the above comments and performed additional research and analyses, including new IPM runs that incorporated higher SCR and natural gas costs and greater electric demand. We also found that more units had installed SCR under the NO_X SIP Call and other regulatory actions than what our records previously showed. This increase in the number of existing SCR installations was also incorporated into these IPM runs. In addition, the number of existing FGD installations was also revised slightly downward, for the same reason.

The revised IPM analyses for today's final action show that the amounts of controls that need to be put on for Phase I are 39.6 GW of FGD and 23.9 GW of SCR. These amounts represent a reduction from the estimates for the NPR. For Phase II, the amount of the required controls are 32.4 GW of FGD and 26.6 GW of SCR. These amounts represent an increase from the estimates for the NPR. The amounts shown for both phases reflect all retrofits required for the CAIR and base case (non-CAIR) policies. The retrofit projections for the base case policies are included, since some of the available boilermaker labor would be consumed in building these retrofits during the CAIR time-frame.

The EPA also contacted the International Brotherhood of Boilermakers (IBB), U.S. Bureau of Labor Statistics (BLS), and National Association of Construction Boilermaker Employers (NACBE) to verify its assumptions on boilermakers population, percentage of boilermakers available to work on the control retrofit projects, and average annual hours of boilermaker employment. Except for the boilermaker population, the information received as a result of these investigations validated EPA's assumptions. IBB also confirmed that the boilermaker population would at least be maintained at the current level of 26,000 members, during the period relevant to construction of CAIR retrofits. It did not want to forecast growth and historically has not done so. Therefore, instead of the 28,000 boilermaker forecasted population used in the NPR, we have conservatively used a boilermaker population of 26,000 for the final CAIR. A detailed discussion on these assumptions and the information received from these sources is available in the docket to this rulemaking as a technical support document (TSD), entitled ''Boilermaker Labor and Installation Timing Analysis, (docket no. OAR–2003–0053–2092).''

The responses to the most significant comments on these issues are summarized in the following sections.

i. Issues Related to Compliance Deadline Extension

(I) Adequacy of Phase I Implementation Period

Today's action initiates State activities in conjunction with EPA to set up the administrative details of CAIR. With the first phase compliance deadline of January 1, 2009, for NO_X and January 1, 2010, for SO_2, the affected sources would have approximately 3¾ and 4¾ years for the implementation of the overall requirements for this phase, respectively. The final SIPs would be submitted at the end of the first 18 months of these implementation periods. The remaining 2¼ and 3¼ years would be available for the sources to complete activities required for the procurement and installation of NO_X and SO_2 controls, respectively. For the reasons outlined below, EPA believes that these deadlines provide enough time to install the required Phase I controls.

(A) Engineering/Construction Schedule Issues

The EPA notes that, for CAIR, the States would finalize the SIPs in 18 months after the rule is signed, and that until then, the majority of sources required to install controls may not initiate activities that require commitment of major funds. However, some activities, such as planning, preparation of conceptual designs, selection of technologies, and contacts with equipment suppliers can be started or completed prior to the finalization of SIPs, at least for major sources expected to require longer implementation periods. In addition, other activities, such as permitting and financing can be started after the rule is finalized. This is based on the NO_X SIP Call experience.

After the SIPs are finalized, the sources would have approximately 2¼ and 3¼ years in which to complete purchasing, detailed design, fabrication, construction, and startup of the required NO_X and SO_2 controls, respectively. This assumes that activities, such as planning and selection of technologies, have already been started or completed, prior to the start of these 2¼- and 3¼-year periods. As discussed in the NPR proposal, EPA projects an average single-unit installation time of 21 months for SCR and 27 months for a scrubber. Our revised IPM analysis for the final rule shows that many facilities would install controls on multiple units (a maximum of six for SCR and five for FGD) at the same plant. We expect these facilities to stagger these installations to minimize operational disruptions.

The EPA also projects that SCRs and scrubbers could be installed on the multiple units in the available time periods of 2¼ and 3¼ years, respectively. The issues related to the availability of boilermakers and the ability of the plants requiring multiple-unit controls to stagger their installations during these periods are discussed later in this preamble.

As compared to projections in the NPR proposal, earlier signing of the final rule adds approximately three additional months to the overall implementation periods for SO_2 controls. Furthermore, EPA's projections for the final rule show fewer Phase I NO_X and SO_2 controls being added than the projections in the NPR proposal. Since the compliance deadline for NO_X has been moved up a year from the proposal, a three-month earlier rule promulgation provides more time for implementing SO_2 controls only. However, since it does allow use of critical resources, such as boilermakers, for SO_2 controls to be spread over a longer period of time, the net effect would be to make more of these resources available for both SO_2 and NO_X controls (as compared to a scenario where promulgation was not three months earlier). This is especially true since the implementation periods for both NO_X and SO_2 controls would start at the same time and the plants installing these controls would be competing for the same resources until January 1, 2009, the compliance deadline for NO_X. The EPA, therefore, believes that 2¼- and 3¼-year time periods provide reasonable amounts of time from the approval of State programs by September 2006, until the commencement of compliance deadlines for meeting the NO_X and SO_2 emission requirements.

Certain commenters have provided their own estimates of schedule requirements for installing the required controls. In some cases, these estimates are longer than those determined by EPA. For scrubbers, including spray dryer and wet limestone or lime type systems, the control implementation requirements provided by the commenters range from 30 to 54 months for the overall project and 18 to 36 months for the phase following equipment awards. In this case, the lowest 18-month schedule requirement cited applies to spray dryers, whereas the shortest schedule cited for wet scrubbers for the activities following the equipment awards is 24 months. For SCR, the control implementation requirements cited by the commenters range from 24 to 36 months for the overall project and 17 to 25 months for the phase following the equipment awards.

One commenter has pointed out that the construction schedule requirements for the FGD and SCR retrofit projects have shortened, because of the lessons learned from a significant number of such projects completed during the last few years. The EPA notes that a recent announcement for a new 485 MW limestone scrubber facility indicates a construction schedule duration (from equipment award to startup) of only 18 months.[72] This is well below the schedule requirement cited by the commenters for a wet limestone scrubber.

The EPA also notes that most of the commenters' schedule estimates are consistent with the time periods available for completing the CAIR-related NO_X and SO_2 projects. Some of the longer schedules submitted by commenters would exceed the CAIR Phase I dates. However, EPA considers these longer schedules to be speculative, as these commenters did not justify them. The major factors that influence schedule requirements include size of the installation, degree of retrofit difficulty, and plant location. The EPA does not expect these factors to make a difference of more than a few months between the schedule requirements of various installations. The commenters who have cited long schedule requirements that fall at the higher end of the above ranges have not provided any data to support the wide differences between their schedules and those proposed by others, including EPA. It should also be noted that EPA's schedules are based on information from several actual SCR and scrubber installations. Therefore, EPA cannot accept the excessive schedule requirements proposed by these commenters.

(B) Landfill Permit Issue

The EPA contacted several key States requiring FGD retrofits, to investigate the amount of time required to obtain a landfill permit for scrubber waste. We note that not all scrubber installations would require landfills, as some scrubber designs produce saleable waste products, such as gypsum.

Specifically, EPA contacted Georgia, Ohio, Indiana, Alabama, Pennsylvania, West Virginia, Tennessee, and Kentucky.[73] Except for Kentucky, all States indicated that their permit approval periods ranged from 12 to 27 months. Some of these States indicated that permit approval may require more time than 27 months, but only for the cases in which major landfill design issues persist or the permit applicant has not provided complete and proper information with the permit application.

The Kentucky Department of Environmental Protection indicated that, based on their historical records, the average permit approval period was 3½ years. They also stated that the State was sensitive to an applicant's time restrictions and the permit approval times had varied depending on the level of urgency surrounding a permit application. They further confirmed that they would work with the industry to meet compliance deadlines, such as those required by CAIR, as efficiently as possible.

Based on the above investigations, EPA notes that the landfill permitting requirements quoted by all States fall well within the 4¾-year implementation period for Phase I. Also, landfill permitting activities as well as its design and construction can be accomplished, independent of the design and construction of the FGD system. The EPA, therefore, believes that landfill permitting is not a constraint for compliance with the rule.

(C) Project Financing Issue

Commenters representing small units or units owned by the co-operatives raised concerns that arrangement of financing for control retrofits could take long periods of time. However, EPA's projections show a larger portion of the smaller units installing controls only during the second phase. These projections also show that only a few co-operative units would require installation of controls. Therefore, EPA believes that the Phase I implementation periods of approximately 3¾ and 4¾ years for NO_X and SO_2 controls, respectively, provide enough time for completing the financing activity for all controls. Of course, if individual sources face difficulties in meeting deadlines to implement controls, they may use the allowance-trading provisions of CAIR to defer implementation of controls.

(D) Electrical Grid Reliability Issue

Based on available data for the NO_X SIP Call, approximately 68 GW of SCR retrofits were started up during the years from 2001 to 2003. This included approximately 42 GW of SCRs in 2003 alone, which exceeds the combined capacity of SCR and FGD retrofits for CAIR that we expect to be started up in any one year. The EPA projects that startup of the 23.9 GW of SCR and 39.6 GW of FGD capacity required for Phase I would be spread over a period of two years (2008 and 2009). The total capacity of units starting up in each year is therefore expected to be approximately 32 GW (half of the combined SCR and FGD capacity of 63.5 GW).

The NO_X SIP Call experience shows that outages required to complete installation of the large SCR capacity, especially during 2003, did not have an adverse impact on the electrical grid reliability. The EPA notes that the outage requirement for SCR usually exceeds that for scrubbers, since SCR is located closer to the boiler and it may be more intrusive to the existing equipment. As shown above, the CAIR retrofits are projected to include more scrubbers than SCRs and the capacity of these retrofits starting up in any one year is below the capacity of the NO_X SIP Call units that started up in 2003. Therefore, the overall outage requirement for CAIR would be less than that experienced for the NO_X SIP Call.

Based on published industry data, the planned outage times for coal-fired units from 2001–2002 (SCR buildup years) decreased by over two percent compared to the previous two years from 1998–1999.[74] The reduction in the overall outage time in the 2001–2002 period also shows that the SCR retrofits did not adversely affect the grid reliability. Therefore, EPA believes that the concern regarding electrical grid reliability is unwarranted for CAIR retrofits.

(II) Availability of Boilermaker Labor in Phase I

The EPA has performed several analyses to verify the adequacy of the available boilermaker labor for the installation of CAIR's Phase I controls. These analyses were not just based on using EPA's assumptions for the key

[72] Reference: Announcement by Wheelabrator Air Pollution Control Inc. for award of a wet limestone scrubber system for K.C. Coleman Generating Station, Western Kentucky Energy Corp., August 2, 2004, and other related documents. (docket no. OAR–2003–0053–1953)

[73] Summary of telephone calls with States to discuss landfill permit timing (docket no. OAR–2003–0053–1927).

[74] Reference: ''NERC, Generating Availability Data System: All MW Sizes—Coal-Fired Generation Report,'' *http://www.nerc.com/~filez/gar.html,* October 17, 2003.

factors affecting the boilermaker availability, but also the assumptions suggested by commenters for these factors to determine how sure we could be on our key conclusions. If there was insufficient labor for the amount of air pollution controls that will need to be installed, the program would be in jeopardy. For instance, shortages in manpower could lead to high wage rates that could substantially increase construction costs for pollution controls and reduce the cost effectiveness of this program. During the peak of the NO_X SIP Call SCR construction period, the power industry did experience an increase in the SCR construction costs. One of the reasons cited for these higher costs was an increased demand for boilermaker labor. The EPA strongly wanted to avoid this possibility for CAIR. The EPA also wanted to be very sure that the levels of controls and timing of the program's start were appropriate. Therefore, EPA tended to make conservative assumptions and to test the sensitivity of key assumptions that were uncertain.

Boilermakers population, percentage of boilermakers available to work on the control retrofit projects, and average annual hours of boilermaker employment are some of the key factors that affect boilermaker availability. As discussed previously, EPA's assumptions on these factors were validated or revised through our discussions with IBB, BLS, and NACBE.

Two other key factors that also have an impact on boilermaker availability include the number of required SCR and FGD retrofits and boilermaker duty rates (boilermaker-year/MW, *i.e.*, the number of boilermaker years needed to install SCR or FGD on one MW of electric generation capacity). The EPA's projections for the required SCR and FGD retrofits are based on the IPM analyses performed for the final rule. The basis for the boilermaker duty rates used by EPA is a report prepared by EPA for the proposed Clear Skies Act, "Engineering and Economic Factors Affecting the Installation of Control Technologies for Multi-Pollutant Strategies."

Some commenters have suggested use of EIA's projections of natural gas prices and electricity demand rates that are higher than EPA's projections used in the IPM analyses. Use of higher values for these parameters would increase the number of required control retrofits. While not agreeing with these commenters that EIA's projections should replace the data that EPA uses, we acknowledge that there is reasonable uncertainty concerning these assumptions and that addressing the uncertainty explicitly by considering EIA's alternative assumptions is prudent, given the importance of having sufficient labor resources to meet the program's requirements in 2010. Therefore, EPA has performed a sensitivity analysis to determine the required control retrofits resulting from the use of these EIA projections, and then used the increased amounts of the required control retrofits to determine their impacts on the boilermaker availability.

The EPA also received comments suggesting that the SCR costs used in our IPM analyses were below the levels experienced in recent SCR installations. We note that the SCR costs were revised in the IPM analyses performed for the final rule, to reflect recent industry experience. One commenter reported SCR capital costs that exceeded our revised costs. The EPA does not agree with these reported costs, as they are not supported by the overall cost data submitted by the commenter. However, to address the concern with the SCR costs in general, we have performed a sensitivity analysis to determine the impact of increasing the SCR capital and fixed O&M costs by 30 percent.

An increase in the SCR costs would affect the amounts of the required control retrofits. Table IV–12 shows the projected Phase I SCR and FGD retrofits for the above two alternate cases, based on using EIA's projections for natural gas prices and electricity demand rates and higher SCR costs.

TABLE IV–12.—IPM PROJECTIONS FOR TOTAL CAPACITIES OF FGD AND SCR RETROFIT PROJECTS FOR COAL-FIRED ELECTRIC GENERATION UNITS FOR CAIR PHASE I USING EPA AND COMMENTER ASSUMPTIONS

Retrofit type	EPA base case assumptions	EIA projections [1]	EIA projections and higher SCR costs [2]
CAIR FGD, GW	37	45.4	47.9
Non-CAIR FGD, GW	2.6	3.7	Included Above
CAIR SCR, GW	18.2	20.6	25.2
Non-CAIR SCR, GW	5.7	4.6	Included Above

[1] The required control retrofits shown are based on using EIA projections for natural gas prices and electricity demand rates.
[2] The required control retrofits shown are based on using EIA projections for natural gas prices and electricity demand rates as well as 30 percent higher SCR capital and fixed O&M costs.

As shown in Table IV–12 above, the alternate case using just the EIA's projections for natural gas prices and electricity demand rates requires the largest amounts of control retrofits. Therefore, a boilermaker availability analysis was performed for just this case.

One commenter has suggested use of higher boilermaker duty rates for both SCR and FGD retrofits, based on an industry survey they had conducted. Use of higher duty rates would result in more boilermakers being needed to install the controls. Table IV–13 shows the boilermaker duty rates used by EPA as well as those suggested by this commenter.

TABLE IV–13.—BOILERMAKER DUTY RATES FOR SCR AND FGD SYSTEMS FOR COAL-FIRED ELECTRIC GENERATION UNITS

Source	FGD	SCR
EPA's estimate, boilermaker-year/MW	0.152	0.175
Commenter-suggested, boilermaker-year/MW [1]	0.269	0.343

[1] The duty rate values shown are average values calculated by using the FGD and SCR correlations provided by the commenter along with the MW size of individual units projected by the IPM to require FGD or SCR controls for Phase I of CAIR.

Our review of the limited supporting information submitted by the commenter about their survey for these duty rates shows that they are based on data from a small number of installations and represent scope of work at each power plant that is well above the average installation conditions used in determining the duty rates used by EPA. Therefore, EPA considers these commenter-suggested duty rates to represent the upper end of the range of values that would be expected for the SCR and FGD controls under consideration. This is also supported by the average duty rate (0.199) submitted by one other commenter for installing FGDs, which is well below the average duty rate (0.269) suggested by the first commenter. However, EPA also notes that the duty rate suggested by the second commenter is higher than that (0.152) used by EPA.

The EPA conducted the boilermaker analysis for the final rule using alternative assumptions for boilermaker duty rates. These alternative assumptions yield a range of estimates of the amount of control that could feasibly be installed. In keeping with EPA's desire to be very sure that there is sufficient boilermaker labor available during the CAIR's Phase I construction period, the Agency has considered the most stringent duty rates suggested by the first commenter, as well as other duty rates (see Table IV–13), in analyzing the impact on the boilermaker availability. The EPA considers this to be a bounding analysis in which the estimates based on the most stringent duty rates reflect conditions with the highest retrofit difficulty level that EPA could realistically expect to occur. We expect that the average boilermaker duty rates applicable to the overall boiler population required to retrofit controls under this rule would not fall outside of the values used by EPA and those suggested by the first commenter.

In the NPR, only the union boilermakers belonging to the IBB were considered in the EPA's availability analysis. Some commenters have pointed out that additional sources of boilermakers will be available for CAIR. Two such sources include non-union and Canadian boilermakers. IBB has confirmed that 1,325 Canadian boilermakers were brought in to support the NO_X SIP Call SCR work in 2003. The EPA also projects that approximately 15 percent of FGDs and 43 percent of SCRs will be installed for Phase I in the traditionally non-union States and believes there will be nonunion labor available in these States. One source has confirmed that a substantial amount of SCR retrofit work during the 2000–2002 period was executed by non-union labor.[75] Based on these data, we have conservatively assumed that 1,000 boilermakers from Canada will be available and 10 percent of the retrofits would be installed by non-union boilermakers for Phase I.

Based on EPA data, an average 32 GW of new gas-fired, combined cycle generating capacity was being added annually, during the NO_X SIP Call SCR construction years of 2002 and 2003. A substantial number of boilermakers were involved in the construction of these gas-fired projects. Since projections for the timeframe relevant to CAIR retrofits show only a small amount of new electric generating capacity being added, the number of boilermakers involved in the building of new plants would be smaller and more of the boilermaker population would be available to work on the Phase I retrofits. As pointed out by one commenter, the boilermakers available due to this projected drop in the building of new generation capacity represents a third additional source of boilermakers for CAIR.

The EPA projects only an insignificant amount of new coal-fired generating capacity being added during Phase I. The most recent EIA's projections also do not show any new coal fired capacity being added between 2007 and 2010, the timeframe relevant to boilermaker-related construction activities for CAIR.[76] However, EPA's projections do show approximately 15 GW of new or repowered gas-fired capacity being added, during 2007–2010. The EIA's projections for new gas-fired capacity addition during Phase I are well below those of EPA's. We used the more conservative EPA projections for new generating capacity additions and the gas-fired capacity additions during the NO_X SIP Call period to estimate the additional boilermaker labor that would become available for the Phase I retrofits. This estimate shows that approximately 28 percent more boilermakers would be available to work on the CAIR retrofits, because of a slowdown in the construction of new power plants.[77]

In the boilermaker availability analyses performed by EPA, the required boilermaker-years were determined for each case, based on the amounts of SCR and FGD retrofits being installed and the pertinent boilermaker availability factors and duty rates. The required boilermaker-years were then compared to the available boilermaker years to verify adequacy of the boilermaker labor. All sources of boilermakers were considered in these analyses, including the union boilermakers and the boilermakers from the three additional sources discussed previously.

The EPA's boilermaker availability analyses firmly support CAIR's Phase I requirements. Using EPA's projections of FGD and SCR retrofits installed for Phase I and EPA's assumptions for boilermaker duty rates, there are ample boilermakers available with a large contingency factor to support the predicted levels of CAIR retrofits. For the most conservative analysis using the boilermaker duty rates suggested by one commenter and the EIA's projections for natural gas prices and electricity demand rates, there are sufficient boilermakers available with a contingency factor of approximately 14 percent.

In the NPR proposal, EPA estimated that a contingency factor of 15 percent was available to offset any increases in boilermaker requirements due to unforeseen events, such as sick leave, time lost due to inclement weather, time lost due to travel between job-sites, inefficiencies created due to project scheduling issues, etc. The EPA had considered this 15 percent contingency factor to be adequate for these unforeseen events. We also note that EPA did not receive any comments suggesting a need for a higher contingency factor.

The EPA also notes that the above boilermaker labor estimates have not considered the benefits of the experiences gained by the U.S. construction industry from the recent buildup of large amounts of air pollution controls, including the NO_X SIP Call SCRs. As pointed out by one commenter, such experiences include use of modular construction, which can result in a significant reduction in the required boilermaker labor for CAIR retrofits. Also, as a result of this controls buildup, an increased number of experienced designers and construction personnel have become available to the industry. Some of these benefits may be offset by factors, such as the increased level of retrofit difficulty expected for the CAIR retrofits, especially for the small size units. However, we believe that the net effect of this experience is a more efficient use of the boilermaker labor in the construction of the air

[75] Reference: "Email from Institute of Clean Air Companies," September 15, 2004 (See Appendix B, Boilermaker Labor Analysis and Installation Timing).

[76] Reference: "Annual Energy Outlook 2005 (Early Release), Tables A9 and 9," December 2004, *http://www.eia.doe.gov/oiaf/aeo/index.html*.

[77] TSD, "Boilermaker Labor and Installation Timing Analysis," (Docket no. OAR–2003–0053–2092).

pollution control retrofits projects. Unfortunately, EPA cannot quantify the value of this experience in determining its overall impact on boilermaker requirements.

Therefore, EPA considers the 14 percent contingency in the available boilermaker-years for the above bounding analysis using commenter-suggested assumptions to be adequate.

ii. Issues Related to Compliance Deadline Acceleration

(I) Acceleration of Phase I Compliance Deadline

As a result of EPA's review of the comments received and further investigations conducted by the Agency for the final rule, the compliance deadline for implementing Phase I NO_X controls has been moved up by one year. We believe that the affected plants would have sufficient time with this change to meet the CAIR requirements associated with NO_X emissions, as long as the compliance deadline for implementing SO_2 controls is not changed. The EPA does not agree that accelerating the originally proposed Phase I compliance deadline of January 1, 2010, for implementing both NO_X and SO_2 controls is possible. These issues are discussed below.

(A) Two-Year Phase I Acceleration for NO_X and SO_2 Controls

With today's final action and allowing 18 months for the SIPs, sources installing controls would have approximately 3¼ years for implementing the rule's requirements. Some commenters suggested moving Phase I forward by 2 years, with a new compliance deadline of January 1, 2008, which would reduce the implementation period to 1¼ years. It is recognized that sources generally would not initiate any implementation activities that require major funding, before the final SIPs are available.

The EPA's projections show that, for SCR installation on one unit, an average 21-month schedule is required to complete purchasing, construction, and startup activities. For the same activities for FGD, an average 27-month schedule is required. As can be seen, the total time required for just one SCR or FGD installation exceeds the 1¼-year implementation period available for Phase I, if the compliance deadline is moved to January 1, 2008.

(B) One-Year Phase I Acceleration for NO_X and SO_2 Controls

If the Phase I compliance deadline for both NO_X and SO_2 controls is moved up by 1 year, the affected facilities would have 2¼ years or 27 months to complete installation of these controls. As discussed in the preceding section, FGD installation on one unit requires an average 27-month schedule to complete purchasing, construction, and startup activities.

The sources installing controls on more than one unit at the same facility would likely stagger the outage-related activities, such as final hookup of the new equipment into the existing plant settings and startup, to minimize operational disruptions and avoid losing too much generating capacity at one time. The EPA projects that an average 2-month period is required to complete the outage construction activities and a 1-month period to complete the startup activities for FGD. Therefore, if back-to-back outages are assumed for a plant installing FGD on just two units, the 27 months needed to install FGD on the first unit and an additional 3 months needed for outage activities on the second unit would result in an overall schedule requirement of 30 months. This 30-month schedule exceeds the available 27-month implementation period, if the compliance deadline is moved up by 1 year. For plants installing FGD controls on more than two units and performing hookup construction and startup activities in back-to-back outages, an additional 3 months would be added to the 30-month schedule requirement for each additional unit.

The EPA notes that certain plants installing multiple-unit controls may be able to meet the compliance deadline requirement by using alternative approaches, such as simultaneous unit outages and purchase of allowances to defer installation of controls on some units. However, our projections for the final rule show that some facilities would be installing FGD controls on five multiple units at a single site. Moreover, these projections show 26 plants requiring FGD retrofit on more than one unit, which represents a major portion of the total number of plants required to install such controls under CAIR. We believe it would not be appropriate to expect this number of plants to resort to alternative means to accommodate such installations, such as simultaneous unit outages or purchasing of allowances.

For FGD retrofits, some plants would be required to obtain solid waste landfill permits. As discussed previously, the time required to obtain these permits could range from one to 3½ years. With the compliance deadline moved up by one year, the overall implementation period would be reduced from 4¾ to 3¾ years. For those plants subjected to a 3½-year permit approval period, only 3 months would be available to prepare the permit applications at the beginning of the compliance period and to prepare the landfill area for accepting the waste after permit approval. The EPA does not believe that 3 months is adequate for such activities. These plants would, therefore, need the 4¾-year implementation period to complete activities related to landfills associated with the FGD systems.

The EPA also performed an analysis to verify if the available boilermaker labor is adequate to support the January 1, 2009, compliance deadline for both NO_X and SO_2. This analysis was performed, using commenter-suggested boilermaker duty rates and EIA's assumptions for the natural gas prices and electricity demand rates. The results show that given these assumptions sufficient number of boilermakers will not be available and that there will be a shortfall of approximately 32 percent in the boilermakers available to support Phase I activities for this case.

Considering the constraints identified in the above analyses for the FGD installation schedule requirements and boilermaker labor availability, EPA believes that it is not reasonable to move the Phase I compliance deadline for both NO_X and SO_2 caps to January 1, 2009.

(C) One-Year Phase I Acceleration for NO_X Controls Only

A 1 year acceleration would result in a compliance deadline of January 1, 2009, for installing Phase I NO_X controls. With this change, the affected sources installing these controls would have approximately 2¼ years for implementing the rule's requirements, following the approval of State programs. However the implementation period for installing FGD controls would still be at 3¼ years.

As shown previously, 21 months would be required to complete purchasing, construction, and startup of SCR on one unit. For multiple-unit installations with back-to-back unit outages for the tie-in construction and startup, the available 2¼-year implementation period would permit staggering of SCR installations on a maximum of three units (see the above referenced TSD). For a plant requiring SCR retrofit on more than three units, simultaneous outages of two units would become necessary. However, EPA notes that there are only six plants projected to require SCR installation on more than three units and, therefore, it is expected that simultaneous outages of two units at each of these plants would not have an adverse impact on the reliability of the electrical grid.

In addition, the plants installing SCR on more than three units at the same site would have two other options to meet the rule's requirements, without having to resort to simultaneous two-unit outages. First, these plants would be able to defer installation of SCRs on some of the units by receiving allocated allowances or purchasing allowances from the 200,000-ton Compliance Supplement Pool being made available as part of CAIR.[78] Second, the outage activities for some of the units at these plants could be extended into the first quarter of 2009, which is beyond the compliance deadline of January 1, 2009, since these units would not generate NO_X emissions during an outage and therefore not require any allowances to compensate for them. The EPA's projections show that, of the above six plants installing SCR on more than three units, four of them require SCR retrofits on four units each. If it is assumed that these four plants would perform outage activities on the fourth unit during the first quarter of 2009, there would only be two plants left that would be required to either purchase allowances or perform work during simultaneous outages.

The EPA also notes that the total schedule requirements for multiple-unit plants can be reduced further by performing some of the activities, especially those related to planning and engineering, prior to the 2¼-year period. Also, with the total installation time requirement for FGD being more than that for SCR, EPA expects the outages associated with most Phase I FGDs to take place after January 1, 2009. The overall impact of the outages taken for these SCR and FGD retrofits would, therefore, be minimized.

The EPA also performed an analysis to determine the impact of an 1-year acceleration in the NO_X compliance deadline on Phase I boilermaker labor requirements. Since the amounts of the required Phase I NO_X and FGD retrofits are not affected by this change, the overall boilermaker requirements for this phase will remain the same as previously reported for the case with the same compliance deadline for both NO_X and SO_2. However, with the new NO_X compliance deadline, installation of all NO_X retrofits would have to be completed by January 1, 2009, and some of the FGD construction work requiring boilermakers would also be done during this period. The EPA assumed that, along with completing installation of all SCRs, 35 percent of the boilermaker labor required to install all FGDs would be used in the period prior to January 1, 2009. This is a conservative assumption, since the amount of boilermaker labor used for this period would be greater than 50 percent of the total Phase I boilermaker labor requirement. The analysis performed by EPA shows that sufficient boilermakers would be available with a contingency factor of approximately 14 percent to install all SCR controls and 35 percent of the FGD retrofit work by January 1, 2009. This analysis is based on the most conservative assumptions, using the boilermaker duty rates suggested by one commenter and the EIA's projections for natural gas prices and electricity demand rates. Based on the above analyses, EPA believes that moving the compliance deadline for Phase I for both NO_X and SO_2 is not practical. However, a 1-year acceleration in the compliance deadline for NO_X only is feasible. Since EPA is obligated under the CAA to require emission reductions for obtaining NAAQS to be achieved as soon as practicable, we have based the final rule on two separate Phase I compliance deadlines of January 1, 2009, and January 1, 2010, for NO_X and SO_2, respectively.

(II) Implementing All Controls in Phase I

The EPA proposed a phased program with the consideration that for engineering and financial reasons, it would take a substantial amount of time to install the projected controls. This program would require one of the most extensive capital investment and engineering retrofit programs ever undertaken in the U.S. for pollution control. The capital investment for pollution control for CAIR that would be installed by 2015 is estimated to be approximately 15 billion dollars. By 2015, close to 340 control unit retrofits will occur. This is occurring at a time when the industry also faces another major infrastructure challenge—upgrading transmission capacity to make the grid more reliable and economic to operate. This also will cost tens of billions of dollars.

The proposed program's objective was to eliminate upwind states' significant contribution to downwind nonattainment, providing air quality benefits as soon as practicable. A phased approach was also considered necessary because more of the difficult-to-retrofit and finance, smaller size units would be included in the second phase, which would allow them to complete activities necessary for implementing the required controls as well as provide them an opportunity to benefit from the lessons learned during the first phase.

In general, environmental controls resulting from legislative or regulatory actions are applied to those units first that offer superior choices from constructability and cost-effectiveness standpoints. Experience gained by the industry from these installations can then be used to develop innovative solutions for any constructability issues and to improve cost effectiveness, as these technologies are applied to harder-to-control units. The EPA believes that this phenomenon applies to the application of the SCR and FGD technologies at coal-fired power plants.

In the last few years, SCR and FGD systems have been added to several existing coal-fired units, under the NO_X SIP Call and Acid Rain Program. These were mainly large units that had features, such as spacious layouts, amenable to the retrofit of the new air pollution control equipment. The units installing controls during Phase I of CAIR would, in general, be smaller in size and would offer relatively more difficult settings to accommodate the new equipment. These units would certainly benefit from the experience the industry has gained from the installations completed in recent years.

A large portion of the units (47 percent) projected to implement controls during the second phase consists of even smaller units, less than 200 MW in size. Compared to larger units, the retrofits for these smaller units would be more difficult to plan, design, and build. Historically, smaller units have been built with less equipment redundancy, smaller capacity margins, and more congested layouts. It is likely, therefore, to be more difficult and require additional design efforts to accommodate the new equipment into the existing settings for the smaller units. Use of lessons learned by firms constructing these units from the previous installations, including those to be built during the first phase, would help streamline this process and maintain the cost effectiveness of these installations. Moving a large portion of the retrofits required for these smaller units to the second phase also provides more time to complete the required retrofit activities.

Because EPA's projections for the second phase include a large proportion of smaller units, the total number of units requiring NO_X and SO_2 controls exceeds that in the first phase (186 vs. 153). Requiring an acceleration of the second phase controls to be completed in the first phase would, therefore, more than double the number of retrofits

[78] The 200,000-ton Compliance Supplement Pool is apportioned to each of the 23 States and the District of Columbia that are required by CAIR to make annual NO_X reductions, as well as the 2 States (Delaware and New Jersey) for which EPA is proposing to require annual NO_X reductions.

required for the first phase from 153 to 339. Based on data available from EPA and other sources, the industry completed 95 SCR installations for the NO_X SIP Call in 2002 and 2003. If the 2004 projections for the NO_X SIP Call are added to this number, the total number of SCR retrofits over the 2002–2004 period would be 140. This is less than half the number that would be required for CAIR during a similar period, if the Phase II requirements are implemented along with the Phase I requirements. Also, the combined capacity for FGD and SCR retrofits required for Phase I would be 122.5 GW, which is approximately 57 percent greater than the installed SIP-Call SCR capacity for the 2002–2004 period. Such a change in the rule would therefore amount to imposing a requirement over the power industry that is significantly more demanding and burdensome than what the industry was required to do under the NO_X SIP Call rule.

The EPA notes that critical resources other than the boilermakers are needed for the installation of SCR and FGD controls, such as construction equipment, engineering and construction staffs belonging to different trades, construction materials, and equipment manufacturers. Some commenters, based on their experience with NO_X SIP Call, also pointed out that the requirement for some of these resources, especially construction equipment (*e.g.*, large cranes used to mount SCR and scrubber vessels above ground), construction materials, equipment manufacturing shop capacities, and engineering and construction management teams overseeing these projects, is affected directly by the number of installations. The greater the requirement is to install a large number of retrofits by 2010, the greater would be the need for all these resources, which would be limited in the short term, as demands from equipment vendors, project teams, and material suppliers ramp up. In the NO_X SIP Call, this led to shortages and bottlenecks in projects in certain areas, causing increased project times and costs. The EPA wants to avoid creating a similar situation by requiring too much at once.

The EPA has also acknowledged the increase in SCR costs during the NO_X SIP Call implementation period, most likely due to an increase in construction costs (resulting from increased demand for boilermaker labor) and steel prices. The EPA has revised its estimates of SCR capital costs in the IPM runs for the final rule and believes the conservatism in its FGD capital costs also accounts for this factor.

The EPA believes that moving the Phase II requirements to the Phase I period could cause near-term shortages in some of the critical resources. This would further increase compliance costs and could remove the highly cost-effective nature of these controls and lead to a greater demand for natural gas.

In addition to the above, financing a large amount of controls for Phase I may prove challenging, especially for the coal plants owned by deregulated generators. As discussed later in this section, such generators are continuing to face serious financial challenges, and many have below investment grade credit ratings. This significantly complicates the financing of costly retrofit controls. Such plants would also not have the certainty of regulatory recovery of investments in pollution control, and would have to rely on the market to recover their costs. Having a second phase cap would allow these companies additional time to strengthen their finances and improve their cash flow.

In the interest of being prudent in evaluating the need to phase in the program, EPA also performed an analysis to determine if the available boilermaker labor would be adequate to support installation of all Phase I and II controls in 2010. This analysis was conservatively based on using commenter-suggested boilermaker duty rates and EIA's projections for gas prices and electricity demand rates. The results show that a sufficient number of boilermakers will not be available and that there will be a shortfall of approximately 25 percent in the boilermakers available to support Phase I activities for this case.

Based on the above analyses, EPA believes that implementation of controls for both phases in Phase I is impractical. We also believe that it is prudent and reasonable in requiring the industry to undertake this massive retrofit program on a two-phase schedule, to be largely completed in less than a decade.

(III) Acceleration of Phase II Compliance Deadline

The EPA does not believe that acceleration of the compliance deadline for the second phase is reasonable. As pointed out earlier, a large portion of the units projected to install controls during the second phase consists of small units, less than 200 MW in size. Due to the issues related to financing of the retrofit projects for some of these units and considering that planning and designing of controls for these units is likely to take longer, EPA does not consider the schedule acceleration to be appropriate.

The EPA notes that Phase I of CAIR is the initial step on the slope of emissions reduction (the glide-path) leading to the final control levels. Because of the incentive to make early emission reductions that the cap-and-trade program provides, reductions will begin early and will continue to increase through Phases I and II. The EPA, therefore, does not believe that all of the required Phase II emission reductions would take place on January 1, 2015, the compliance deadline. These reductions are expected to accrue throughout the implementation period, as the sources install controls and start to test and operate them.

The EPA also notes that the 5-year implementation period for Phase II is consistent with other regulations and statutory requirements, such as title IV for SO_2 and NO_X controls. In addition, some commenters have cited a need for a 6-year period for obtaining financing for plants owned by the co-operatives. These facilities are likely to commit funds for major activities, only after financing has been obtained. Therefore, for such facilities, a period of approximately four years would be available for procuring, installing, and startup activities, assuming that the financing activities were started right after the rule is finalized. Since the plants owned by co-operatives are usually small in size, they are likely to require and be benefitted by the extra time allowed to them by this four-year implementation period.

The EPA also performed an analysis to verify adequacy of the available boilermaker labor for pollution control retrofits the power industry will install to comply with the Phase II CAIR requirements. A 36-month construction period requiring boilermakers was conservatively selected for this analysis. Based on the IPM analysis for the final rule, conservatively, the power industry will build 27.5 GW of FGD and 26.6 GW of SCR retrofits for compliance with lower emission caps that go into effect for NO_X and SO_2 in 2015. The analysis was based on using EIA's projections for the natural gas prices and electricity demand rates and the commenter-suggested boilermaker duty rates. The results show availability of ample boilermakers with a contingency factor of 46 percent to support Phase II activities.

The EPA notes that the retrofits that will occur in Phase II will be smaller, more numerous, and more challenging, since the easiest controls will likely be installed in Phase I. Therefore, having a greater contingency factor (as we do) is warranted. This is further supported when the uncertainty in predicting the construction activities in the areas outside of air pollution controls is considered. Notably after 2010, the excess generation capacity that we have today is no longer expected to be present and there may be a shift towards a requirement for increasing generation capacity. Increased construction of new power plants will have a direct impact on the availability of boilermakers for the Phase II controls. The EPA believes that a higher contingency factor for Phase II is desirable to ensure that the industry will succeed in getting the required reductions at the required time.

Any acceleration of the Phase II compliance deadline will also cause an appreciable reduction in the above estimated contingency factor for boilermaker labor. For example, based on EPA analysis, an acceleration of one year is projected to reduce this contingency factor to only about one percent. Therefore, EPA believes that acceleration of the Phase II compliance deadline cannot be justified.

3. Assure Financial Stability

The EPA recognizes that the power sector will need to devote large amounts of capital to meet the control requirements of the first phase. Furthermore, over the next 10 years, the power sector is facing additional financial challenges unrelated to environmental issues, including economic restructuring impacts, investments related to domestic security and investments related to electrical infrastructure. Among the consideration of other factors, EPA believes it is important to take into account the ability of the power sector to finance the controls required under CAIR. A detailed assessment of the status of the financial health of the U.S. Utility Industry, particularly of the unregulated sector is offered in the TSD, ''U.S. Utility Industry Financial Status and Potential Recovery.''

Commenters have noted that they appreciate EPA's growing realization that many companies may have difficulty securing financing, and the agency's establishment of a two-phase reduction program on both technical and financial grounds.

Utilities and non-utility generating companies have felt significant financial pressure over the past 5 years. The years 2000 and 2001 saw the escalation and fallout from the California energy crisis, the bankruptcy of Enron, and a massive building program, largely on the side of the merchant generating sector. Subsequent low power margins and large debt obligations have led to a significant number of credit downgrades of utilities and power generators and the bankruptcy of coal-generating merchant companies. According to Standard and Poor's, a leading provider of investment ratings, there were almost ten times more downgrades of utility credit in 2002 and 2003 than there were upgrades. While more recently the sector has stabilized, a significant number of owners of coal-fired capacity in the CAIR region, particularly those with deregulated capacity, are still at below investment-grade credit ratings.

In general, EPA believes that regulated plants, given appropriate regulatory requirements, should not face significant financial problems meeting their obligations under CAIR. While EPA recognizes that issues such as the expiration of rate caps and the time lags associated with regulatory approval and recovery may provide cash flow challenges, regulated electricity rates are generally seen as a positive factor in credit ratings, as entities are allowed a recovery on prudent investment through rate cases (and, in some jurisdictions, the recovery of allowance expenditures through fuel adjustment clauses).

Deregulated coal capacity (operating in an environment of market prices rather than electricity rates set by regulators) has no such guarantees, and would need to recover investments in pollution control from market prices (which in many cases are not set by coal units). Additionally, deregulated entities, because of their more aggressive building and borrowing strategies and reliance on market prices (which now reflect the current capacity overbuild), have faced more significant financial difficulties (including a number of bankruptcies) and are currently in a weaker position financially.[79] A number of firms that have avoided financial distress in the near term have done so by renegotiating their pending debt, postponing payment. A good portion of this debt is of a shorter-term nature, and will be coming due in the next five years.

Such financial difficulties increase the cost of capital necessary for capital expenditures and affect the availability of such capital, making required controls more expensive. Recent financial troubles have been cited as the reason for the deferment or cancellation of pollution control expenditures. Should interest rates rise in the future, it will become more difficult and costly for utilities seeking financing.

These problems impact a significant segment of coal generators, as deregulated coal capacity makes up about a third of all U.S. coal capacity and almost 90 percent of this deregulated capacity would be affected by CAIR requirements.

Given the lead times needed to plan and construct such equipment, as well as the financial uncertainty many of the plant owners are confronting, companies may find it difficult to install controls at their plants too quickly. The EPA believes that the choice of timing of the emission caps in CAIR would allow firms time to improve their current and near-term financial difficulties (through reorganization, mergers, sales, etc.). Phasing in the more stringent emission caps by 2015 would also spread investment requirements and resulting cash flow demands, rather than forcing firms to finance a large spike in investments in a very short time period, while they are still trying to recover financially.

The timing of controls expected to be installed as a result of CAIR are similar to that noted in EPA's analysis of the Clear Skies proposal. The EPA looked in detail at the potential financial impact of the Clear Skies program (particularly focusing on the deregulated coal sector). The EPA found that some individual deregulated coal plants might be adversely affected, but on average such plants would actually experience a small financial improvement under Clear Skies. Baseload deregulated coal plants would benefit from even slight increases in the price of natural gas (units burning natural gas generally set the wholesale price of electricity on the margin in the regions where deregulated coal is located). These units would also be recipients of allocated allowances. Overall, the phased in nature of CAIR, the fact that most coal plants continue to be regulated and the fact that sources would also receive allowances, would all mitigate the financial impact of this rule.

The EPA believes that the timing requirements finalized today reflect a prudent and cautious approach designed to assure that the industry will succeed in implementing this program. The EPA believes that deferring the second phase to 2015 will provide enough time for companies to raise additional capital needed to install controls. Also, we believe that the implementation period should account (at least broadly) for the possibility that electricity demand or natural gas prices may increase more than assumed, and therefore that additional control equipment would be needed. Allowing until 2015 for implementation of the more stringent control levels in today's rule will provide more flexibility in the

[79] In fact, between nine and eleven (depending on the credit agency) of the twenty largest owners of deregulated coal capacity in the U.S. currently have below-investment-grade credit ratings.

event of greater electricity demand and will ensure that power plants in the CAIR region will have the ability, both technical and financial, to make the pollution control retrofits required.

Currently, EPA is cooperating with the National Association of Regulatory Utility Commissioners (NARUC) in developing a menu of policy options and financial incentives for encouraging improved environmental performance for generation. A survey of a number of States was conducted as part of this effort, and policies such as pre-approval statutes for compliance plans, state income tax credits, accelerated depreciation, and special treatment of allowance transactions were cited as examples of such policies [80]. Such policies will ease some of the financial pressures of CAIR by providing greater regulatory certainty and lowering the effective costs of controls.

D. Control Requirements in Today's Final Rule

1. Criteria Used To Determine Final Control Requirements

The EPA's general approach to developing emission reduction requirements—basing the requirements on the application of highly cost-effective controls—was adopted in the NO_X SIP Call and has been sustained in court. In the NPR, the Agency proposed this approach for developing SO_2 and NO_X emission reduction requirements. The majority of commenters accepted this basic approach for determining reduction requirements. Some commenters did suggest other approaches, however, as discussed above.

Many commenters suggested that the CAIR regionwide SO_2 and NO_X control levels should be more or less stringent than the levels proposed in the NPR. The EPA has determined that the control levels that we are finalizing today are highly cost-effective and feasible, and constitute substantial reductions that address interstate transport, at the outset of State and EPA efforts to bring about attainment of the $PM_{2.5}$ NAAQS (EPA believes that most if not all States will obtain CAIR reductions by capping emissions from the power sector). Today, EPA finalizes the use of both average and marginal cost effectiveness of controls as the basis for determining the highly cost-effective amounts.

In the CAIR NPR, EPA proposed criteria for determining the appropriate levels of SO_2 and NO_X emissions reductions, and stated that EPA considered a variety of factors in evaluating the source categories from which highly cost-effective reductions may be available and the level of reduction assumed from that sector (69 FR 4611). The EPA has reviewed comments on its NPR, SNPR and NODA and conducted further analyses with respect to the proposed criteria, and is finalizing its control requirements in today's action. Following is a brief summary of EPA's conclusions based on the criteria.

The availability of information, and the identification of source categories emitting relatively large amounts of the relevant emissions, are two criteria used in EPA's evaluation of the CAIR program. In the NPR, EPA stated that EGUs are the most significant source of SO_2 emissions and a very substantial source of NO_X in the affected region, and further stated that highly cost-effective control technologies are available for achieving significant SO_2 and NO_X emissions reductions from EGUs. We requested comment on sources of information for emissions and costs from other sectors (69 FR 4610). A detailed discussion regarding non-EGU sources is provided above. The EPA has not received additional information that would change its proposed control strategy.

Another criterion is the performance and applicability of control measures. The NPR included a detailed discussion of the performance and applicability of SO_2 and NO_X control technologies for EGUs. In particular, EPA discussed FGD for SO_2 removal and SCR for NO_X removal, both of which are fully demonstrated and available pollution control technologies on coal-fired EGU boilers (69 FR 4612). None of the commenters provided information that differed from EPA's assessment of the performance of these control measures. In addition, the commenters generally supported EPA's assumptions on the applicability of these controls.

The cost effectiveness of control measures is another criterion used in EPA's analysis. As discussed in detail above, EPA determined that the proposed control levels are highly cost-effective, and is finalizing the levels in today's action. The EPA used IPM to analyze the cost effectiveness of the proposed and final CAIR control requirements. IPM incorporates assumptions about the capital costs and fixed and variable operations and maintenance costs of control measures for EGUs. Several commenters suggested that the SCR control cost assumptions that we used in IPM analysis for the NPR were too low. Consequently, we increased the SCR control cost assumptions in IPM and conducted cost effectiveness modeling for the final control requirements using these updated costs.[81] Commenters generally supported our FGD control costs assumptions, which are largely unchanged from the NPR modeling to the modeling for today's final rule.

And finally, EPA considered engineering and financial factors that affect the availability of control measures. The EPA conducted a detailed analysis of engineering factors that affect timing of control retrofits, including an evaluation of the comments received. The EPA's analysis supports its compliance schedule, a two-phase emissions control program with the final phase commencing in 2015, and with a first phase commencing in 2010 for SO_2 reductions and in 2009 for NO_X reductions. Further, EPA's analysis demonstrates that it would not be realistically possible to start the program sooner, or to impose more stringent emissions caps in the first phase.

Based on EPA's review of comments and analysis, EPA determined that the proposed control requirements are reasonable with respect to engineering factors. As discussed above, EPA also considered how to avoid creating financial instability for the affected sector, and how to ensure the capital needed for the required controls would be readily available. Assuming States choose to control EGUs, the power sector will need to devote large amounts of capital to meet the CAIR control requirements.

The EPA explained that implementing CAIR as a two-phase program, with the more stringent control levels commencing in the second phase, will allow time for the power sector to address any financial challenges. The EPA's evaluation of engineering and financial factors supports the decision to implement CAIR as a two-phase program, with the final (second) compliance level commencing in 2015 and a first phased-in level starting in 2010 for SO_2 reductions and in 2009 for NO_X reductions. A description of the final CAIR control requirements follows.

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[80] The survey results are in "A Survey of State Incentives Encouraging Improved Environmental Performance of Base-Load Electric Generation Facilities: Policy and Regulatory Initiatives," at *http://www.naruc.org/displayindustryarticle.cfm?articlenbr=21826.*

[81] Detailed documentation of EPA's IPM update, including updated control cost assumptions, is in the docket. The SCR control cost assumptions were presented in a peer-reviewed paper by Sikander Khan and Ravi Srivastava, "Updating Performance and Cost of NO_X Control Technologies in the Integrated Planning Model," at the Combined Power Plant Air Pollution Control Mega Symposium, August 30–September 2, 2004, Washington, DC.

2. Final Control Requirements

Today's final rule implements new annual SO_2 and NO_X emissions control requirements to reduce emissions that significantly contribute to $PM_{2.5}$ nonattainment. The final rule also requires new ozone season NO_X emissions control requirements to reduce emissions that significantly contribute to ozone nonattainment.

The final rule requires annual SO_2 and NO_X reductions in the District of Columbia and the following 23 States: Alabama, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin. (In the "Proposed Rules" section of today's action, EPA is publishing a proposal to include Delaware and New Jersey in the CAIR region for annual SO_2 and NO_X reductions.)

In addition, the final rule requires ozone season NO_X reductions in the District of Columbia and the following 25 States: Alabama, Arkansas, Connecticut, Delaware, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

The CAIR requires many of the affected States to reduce annual SO_2 and NO_X emissions as well as ozone season NO_X emissions. However, there are three States for which only annual emission reductions are required (Georgia, Minnesota and Texas). Likewise, there are five States for which only ozone season reductions are required (Arkansas, Connecticut, Delaware, Massachusetts, and New Jersey). The following 20 States and the District of Columbia are required to make both annual and ozone season reductions: Alabama, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia and Wisconsin.

Table IV–14 shows the amounts of regionwide annual SO_2 and NO_X emissions reductions under CAIR that EPA projects, if States choose to meet their CAIR obligations by controlling EGUs. Table IV–15 shows the amounts of regionwide ozone season NO_X emissions reductions under CAIR that EPA projects, if States choose to meet their CAIR obligations by controlling EGUs. If all affected States choose to implement these reductions through controls on EGUs, the regionwide annual SO_2 and NO_X emissions caps that would apply for EGUs are also shown in the Table IV–14, and ozone season NO_X caps for EGUs are in Table IV–15. Base case emissions levels for affected EGUs as well as emissions with CAIR are also shown in Table IV–14 and Table IV–15, based on IPM modeling.

The EPA is finalizing the regionwide EGU SO_2 emissions caps—if States choose to comply by controlling EGUs—as shown in Table IV–14 [82]. As indicated above, EPA identified SO_2 budget amounts, as target levels for further evaluation, by adding together the title IV Phase-II allowances for all of the States in the CAIR region, and making a 50 percent reduction for the 2010 cap and a 65 percent reduction for the 2015 cap. The EPA determined, through IPM analysis, that the resulting regionwide emissions caps (if all States choose to obtain reductions from EGUs) are highly cost-effective levels.

Also, EPA is finalizing the regionwide EGU annual and ozone season NO_X emission caps—if States choose to comply by controlling EGUs—as shown in Table IV–14 and Table IV–15.[83] As indicated above, EPA identified NO_X budget amounts, as target levels for further evaluation, through the methodology of determining the highest recent Acid Rain Program heat input from years 1999–2002 for each affected State, summing the highest State heat inputs into a regionwide heat input, and multiplying the regionwide heat input by 0.15 lb/mmBtu and 0.125 lb/mmBtu for 2009 and 2015, respectively. The EPA determined, through IPM analysis, that the resulting regionwide emissions caps (if all States choose to obtain reductions from EGUs) are highly cost-effective levels.

The emission reductions, EGU emissions caps, and emissions shown in Table IV–14 are for the 23 States and the District of Columbia that are required to make annual SO_2 and NO_X reductions for CAIR. (Table IV–14 does not include information for the five States that are required to make ozone season reductions only.)

The emission reductions, EGU emissions caps, and emissions shown in Table IV–15 are for the 25 States and the District of Columbia that are required to make ozone season NO_X reductions for CAIR. (Table IV–15 does not include information for the three States that are required to make annual reductions only.)

The EPA is requiring the CAIR SO_2 and NO_X emissions reductions in two phases. For States affected by annual SO_2 and NO_X emission reductions requirements, the final (second) phase commences January 1, 2015, and the first phase begins January 1, 2010 for SO_2 reductions and January 1, 2009 for NO_X reductions. For States affected by ozone season NO_X emission reductions requirements, the final (second) phase commences May 1, 2015 and the first phase starts May 1, 2009. Notably, the first phase control requirements are effective in years 2010 through 2014 for SO_2 and in years 2009 through 2014 for NO_X, and the 2015 requirements are for that year and thereafter.

TABLE IV–14.—FINAL RULE SO_2 AND NO_X ANNUAL BASE CASE EMISSIONS, EMISSION CAPS, EMISSIONS AFTER CAIR AND EMISSION REDUCTIONS IN THE REGION REQUIRED TO MAKE ANNUAL SO_2 AND NO_X REDUCTIONS (23 STATE AND DC) FOR THE INTERIM PHASE (2010 FOR SO_2 AND 2009 FOR NO_X) AND FINAL PHASE (2015 FOR SO_2 AND NO_X) FOR EGUS

(Million Tons) [84]

	Base case emissions	CAIR emissions caps	Emissions after CAIR	Emissions reduced
First phase (2010 for SO_2 and 2009 for NO_X)				
SO_2	8.7	3.6	5.1	3.5
NO_X	2.7	1.5	1.5	1.2

[82] For a discussion of the emission reduction requirements if States choose to control sources other than EGUs, see section VII of this preamble.

[83] For a discussion of the emission reduction requirements if States choose to control sources other than EGUs, see section VII of this preamble.

TABLE IV–14.—FINAL RULE SO_2 AND NO_X ANNUAL BASE CASE EMISSIONS, EMISSION CAPS, EMISSIONS AFTER CAIR AND EMISSION REDUCTIONS IN THE REGION REQUIRED TO MAKE ANNUAL SO_2 AND NO_X REDUCTIONS (23 STATE AND DC) FOR THE INTERIM PHASE (2010 FOR SO_2 AND 2009 FOR NO_X) AND FINAL PHASE (2015 FOR SO_2 AND NO_X) FOR EGUS—Continued

(Million Tons)[84]

	Base case emissions	CAIR emissions caps	Emissions after CAIR	Emissions reduced
Sum	11.4	NA	6.6	4.8
Second Phase (2015 for SO_2 and NO_X)				
SO_2	7.9	2.5	4.0	3.8
NO_X	2.8	1.3	1.3	1.5
Sum	10.6	NA	5.3	5.3

Notes: Numbers may not add due to rounding.

1. The emission caps that EPA used to make its determination of highly cost-effective controls and the emission reductions associated with those caps are shown in Table IV–14. For a discussion of the emission reduction requirements if States control source categories other than EGUs, see section VII in this preamble. Emissions shown here are for EGUs with capacity greater than 25 MW.
2. The District of Columbia and the following 23 States are affected by CAIR for annual SO_2 and NO_X controls: AL, FL, GA, IA, IL, IN, KY, LA, MD, MI, MN, MO, MS, NY, NC, OH, PA, SC, TN, TX, VA, WV, WI.
3. The 2010 SO_2 emissions cap applies to years 2010 through 2014. The 2009 NO_X emissions cap applies to years 2009 through 2014. The 2015 caps apply to 2015 and beyond.
4. Due to the use of the existing bank of SO_2 allowances, the estimated SO_2 emissions in the CAIR region in 2010 and 2015 are higher than the emissions caps.
5. Over time the banked SO_2 emissions allowances will be consumed and the 2015 cap level will be reached. SO_2 emissions levels can be thought of as on a flexible "glide path" to meet the 2015 CAIR cap with increasing reductions over time. The annual SO_2 emissions levels in 2020 with CAIR are forecasted to be 3.3 million tons within the region encompassing States required to make annual reductions, an annual reduction of 4.4 million tons from base case levels.

TABLE IV–15.—FINAL RULE NO_X OZONE SEASON BASE CASE EMISSIONS, EMISSIONS CAPS, EMISSIONS AFTER CAIR AND EMISSION REDUCTIONS IN THE REGION REQUIRED TO MAKE OZONE SEASON NO_X REDUCTIONS (25 STATES AND DC) FOR THE INTERIM PHASE (2009) AND FINAL PHASE (2015) FOR ELECTRIC GENERATION UNITS

(Million Tons)[85]

Ozone Season NO_X				
Phase	Base case emissions	CAIR emissions caps	Emissions after CAIR	Emissions reduced
2009	0.7	0.6	0.6	0.1
2015	0.7	0.5	0.5	0.2

Notes:

1. The emission caps that EPA used to make its determination of highly cost-effective controls and the emission reductions associated with those caps are shown in Table IV–15. For a discussion of the emission reduction requirements if States control source categories other than EGUs, see section VII in this preamble. Emissions shown here are for EGUs with capacity greater than 25 MW.
2. The District of Columbia and the following 25 States are affected by CAIR for ozone season NO_X controls: AL, AR, CT, DE, FL, IA, IL, IN, KY, LA, MA, MD, MI, MO, MS, NJ, NY, NC, OH, PA, SC, TN, VA, WV, WI.
3. The 2009 NO_X emissions cap applies to years 2009 through 2014. The 2015 cap applies to 2015 and beyond.

Table IV–16 shows the estimated amounts of regionwide annual SO_2 and NO_X emissions reductions that would occur if EPA finalizes its proposal to find that Delaware and New Jersey contribute significantly to downwind $PM_{2.5}$ nonattainment, and if all affected States choose to control EGUs (the proposal is published in the "Proposed Rules" section of today's action). In that case, the estimated regionwide annual SO_2 and NO_X emissions caps that would apply for EGUs are as shown in Table IV–16. Annual base case emissions levels for EGUs in the CAIR region (including Delaware and New Jersey) as well as emissions with CAIR are also shown in the Table, based on IPM modeling. If EPA finalizes its proposal to include Delaware and New Jersey for $PM_{2.5}$ requirements, then the ozone

[84] Table IV–14 includes regionwide information for the 23 States and DC that are required by CAIR to make annual emission reductions. It does not include information for the 5 CAIR States that are required to make ozone season reductions only. The CAIR requires NO_X emission reductions in a total of 28 States and DC. For 20 States and DC, both annual and ozone season NO_X reductions are required. For 3 States only annual reductions are required, and for 5 States only ozone season reductions are required. The total projected NO_X emission reductions that will result from CAIR—if all States control EGUs—include the annual reductions shown in Table IV–14 (for 23 States and DC) plus the ozone season reductions in the 5 States required to make ozone season reductions only. The EPA projects the total NO_X reductions, in all 28 CAIR States and DC, to be 1.2 million tons in 2009 and 1.5 million tons in 2015. Note that the values in this table represent the final CAIR policy and differ slightly from the values in the RIA (which were based on an earlier and slightly different IPM) (see more detailed discussion both earlier in this section and in the RIA).

[85] Table IV–15 shows regionwide information for the 25 States and DC that are required to make ozone season emission reductions under CAIR. It does not include information for the 3 States that are required to make annual emission reductions only.

season requirements would not change for States required to make ozone season reductions for CAIR.

Based on EPA modeling with Delaware and New Jersey included in the $PM_{2.5}$ region (and if all affected States choose to control EGUs), the EGU emissions caps and the ozone season NO_X emissions and emission reductions associated with those caps, for the 25 States and the District of Columbia that are required to make ozone season NO_X reductions, would be as shown in Table IV–15, above.[86]

TABLE IV–16.—SO_2 AND NO_X ANNUAL BASE CASE EMISSIONS, EMISSIONS CAPS, EMISSIONS AFTER CAIR AND EMISSION REDUCTIONS IN THE REGION REQUIRED TO MAKE ANNUAL SO_2 AND NO_X REDUCTIONS (25 STATES AND DC) FOR THE INITIAL PHASE (2010 FOR SO_2 AND 2009 FOR NO_X) AND FINAL PHASE (2015 FOR SO_2 AND NO_X) FOR ELECTRIC GENERATION UNITS IF EPA FINALIZES ITS PROPOSAL TO INCLUDE DELAWARE AND NEW JERSEY FOR $PM_{2.5}$ REQUIREMENTS

[Million tons] [87]

	First phase (2010 for SO_2 and 2009 for NO_X)			
	Base case emissions	CAIR emissions caps	Emissions after CAIR	Emissions reduced
SO_2	8.8	3.7	5.2	3.6
NO_X	2.8	1.5	1.5	1.2
Sum	11.5	NA	6.7	4.8
	Second phase (2015 for SO_2 and NO_X)			
	Base case emissions	CAIR emissions caps	Emissions after CAIR	Emissions reduced
SO_2	7.9	2.6	4.1	3.9
NO_X	2.8	1.3	1.3	1.5
Sum	10.7	NA	5.3	5.4

Note: Numbers may not add due to rounding.

1 The emission caps that EPA used to make its determination of highly cost-effective controls and the emission reductions associated with those caps are shown in Table IV–16. For a discussion of the emission reduction requirements if States control source categories other than EGUs, see section VII in this preamble. Emissions shown here are for EGUs with capacity greater than 25 MW.

2 The District of Columbia and the following 25 States would be affected by CAIR for annual SO_2 and NO_X controls if EPA finalizes its proposal to include DE and NJ: AL, DE, FL, GA, IA, IL, IN, KY, LA, MD, MI, MN, MO, MS, NJ, NY, NC, OH, PA, SC, TN, TX, VA, WV, WI.

3 The 2010 SO_2 emissions cap would apply to years 2010 through 2014. The 2009 NO_X emissions cap would apply to years 2009 through 2014. The 2015 caps would apply to 2015 and beyond.

4 Due to the use of the existing bank of SO_2 allowances, the estimated SO_2 emissions in the CAIR region in 2010 and 2015 would be higher than the emissions caps.

5 Over time the banked SO_2 emissions allowances would be consumed and the 2015 cap level would be reached. SO_2 emissions levels can be thought of as on a flexible "glide path" to meet the 2015 CAIR cap with increasing reductions over time. The annual SO_2 emissions levels in 2020 with CAIR, within the region of States required to make annual reductions (including Delaware and New Jersey), are forecasted to be 3.3 million tons, an annual reduction of 4.4 million tons from base case levels.

The EPA apportioned the EGU caps—and associated required regionwide emission reductions—on a State-by-State basis. The affected States may determine the necessary controls on SO_2 and NO_X emissions to achieve the required reductions. The EPA's apportionment method and the resulting State EGU emissions budgets are described in Section V in today's preamble.

To achieve the required SO_2 and NO_X reductions in the most cost-effective manner, EPA suggests that States implement these reductions by controlling EGUs under a cap and trade program that EPA would implement.

However, the States have flexibility in choosing the sources that must reduce emissions. If the States choose to require EGUs to reduce their emissions, then States must impose a cap on EGU emissions, which would in effect be an annual emissions budget. Provisions for allocating SO_2 and NO_X allowances to individual EGUs—which apply if a State chooses to control EGUs and elects to allow them to participate in the interstate cap and trade program—are presented elsewhere in today's preamble. If a State wants to control EGUs, but does not want to allow EGUs to participate in the interstate cap and trade program, the State has flexibility in allocating allowances, but it must cap EGUs. Sources that are subject to the emission reduction requirements under title IV continue to be subject to those requirements.

If the States choose to control other sources, then they must employ methods to assure that those other sources implement controls that will yield the appropriate amount of annual emissions reduction. See section VII (SIP Criteria and Emissions Reporting Requirements) in today's preamble.

Implementation of the cap and trade program is discussed in section VIII in today's preamble.

For convenience, we use specific terminology to refer to certain concepts. "State budget" refers to the statewide

86 For a discussion of the emission reduction requirements if States choose to control sources other than EGUs, see section VII of this preamble.

87 Table IV–16 includes regionwide information for the 25 States and DC that will be required to make annual emission reductions if EPA finalizes its proposal to require annual reductions in Delaware and New Jersey under CAIR. The table does not include information for the 3 States (Arkansas, Connecticut, and Massachusetts) that would be affected by CAIR for ozone season reductions only.

emissions that may be used as an accounting technique to determine the amount of annual or ozone season emissions reductions that controls may yield. It does not imply that there is a legally enforceable statewide cap on emissions from all SO_2 or NO_X sources. ''Regionwide budget'' refers to the amount of emissions, computed on a regionwide basis, which may be used to determine State-by-State requirements. It does not imply that there is a legally enforceable regionwide cap on emissions from all SO_2 or NO_X sources. ''State EGU budget'' refers to the legally enforceable annual or ozone season emissions cap on EGUs a State would apply should it decide to control EGUs.

V. Determination of State Emissions Budgets

The EPA outlined in the NPR and SNPR its proposals regarding a methodology for setting both regional and State-level SO_2 and NO_X budgets. Section IV explains how the regionwide budgets were developed. This section V describes how EPA apportions the regionwide emissions reductions—and the associated EGU caps—on a State-by-State basis, so that the affected States may determine the necessary controls of SO_2 and NO_X emissions.

In the NPR and SNPR, EPA proposed annual SO_2 and NO_X caps for States contributing to fine particle nonattainment and separate ozone-season only caps for States contributing to ozone—but not fine particle—nonattainment. The EPA is finalizing an annual cap for both SO_2 and NO_X for States that contribute to fine particle nonattainment. In addition, EPA is finalizing an ozone-season only cap for NO_X for all States that contribute to ozone nonattainment.

States have several options for reducing emissions that significantly contribute to downwind nonattainment. They can adopt EPA's approach of reducing the emissions in a cost-effective manner through an interstate cap and trade program. This approach would, by definition, achieve the required cost-effective reductions. Alternately, States could achieve all of the necessary emissions reductions from EGUs, but choose not to use EPA's interstate emissions trading program. In this case, a State would need to demonstrate that it is meeting the EGU budgets outlined in this section. Finally, States could obtain at least some of their required emissions reductions from sources other than EGUs. Additional detail on these options is provided in section VII.

A. What Is the Approach for Setting State-by-State Annual Emissions Reductions Requirements and EGU Budgets?

This section presents the final methodologies used for apportioning regionwide emission reduction requirements or budgets to the individual States.

In the CAIR NPR, EPA proposed methods for determining the SO_2 and NO_X emission reduction requirements or budgets for each affected State. In the June 2004 SNPR, EPA proposed corrections and improvements to the proposals in the CAIR NPR. In the August 2004 NODA, EPA presented the corrected NO_X budgets resulting from the improvements proposed in the SNPR.

1. SO_2 Emissions Budgets

a. State Annual SO_2 Emission Budget Methodology

As noted elsewhere in today's preamble, the regionwide annual budget for 2015 and beyond is based on a 65 percent reduction of title IV allowances allocated to units in the CAIR States for SO_2 control. The regionwide annual SO_2 budget for the years 2010–2014 is based on a 50 percent reduction from title IV allocations for all units in affected States.

In the NPR and SNPR, EPA also proposed calculating annual State SO_2 budgets based on each State's allowances under title IV of the 1990 CAA Amendments. We are finalizing this proposed approach for determining State annual SO_2 budgets.

State annual budgets for the years 2010–2014 (Phase I) are based on a 50 percent reduction from title IV allocations for all units in the affected State. The State annual budget for 2015 and beyond (Phase II) is based on a 65 percent reduction of title IV allowances allocated to units in the affected State for SO_2 control.

Some commenters criticized EPA's basing State budgets on title IV allocations since these were based largely on 1985–1987 historic heat input data. Commenters argue that the initial allocation was not equitable and that in any event, the electric power sector has changed significantly. They conclude that State budgets should reflect those differences. Commenters have also commented that tying SO_2 allocations to title IV also does not let States account for units that are exempt from title IV or for new units that have come online since 1990.

While acknowledging these concerns, EPA believes, for a number of reasons, that setting State budgets according to title IV allowances represents a reasonable approach.

The EPA believes that basing budgets on title IV allowances is necessary in order to ensure the preservation of a viable title IV program, which is important for reasons discussed in section IX of this preamble. Such reasons include the desire to maintain the trust and confidence that has developed in the functioning market for title IV allowances. The EPA believes it is important not to undermine such confidence (which is an essential underpinning to a viable market-based system) recognizing that it is a key to the success of a trading program under the CAIR.

The title IV program represents a logical starting point for assessing emissions reductions for SO_2, since it is the current effective cap on SO_2 emissions for Acid Rain units, which make up the large majority of affected EGU CAIR units. It is from this starting emissions cap, that further CAIR reductions are required. Consequently, EPA proposes State-level reductions based on reductions from the initial allocations of title IV allowances to individual units at sources (power plants) in States covered by the CAIR.

The setting of SO_2 budgets differs from the setting of NO_X budgets for the CAIR, in part, because of this difference in starting points—since there is no existing NO_X regional annual cap, and no currency for emissions, on which sources rely. Furthermore, Congress, as part of title IV of the CAA, decided upon the allocations of title IV allowances specifically for the control of SO_2, and not for NO_X.

Moreover, Congress decided to allocate title IV allowances in perpetuity, realizing that the electricity sector would not remain static over this time period. Congress clearly did not choose a policy to regularly revisit and revise these allocations, believing that its allocations methodology for title IV allowances would be appropriate for future time periods.

The EPA realizes, putting aside concerns of linkage to title IV, that there are numerous potential methodologies of dividing up the regional budgets among the States. Also, EPA believes, that while initial allocations of State budgets are important for distributional reasons, under a cap and trade system, they would not impact the attainment of the environmental objectives or the overall cost of this rule.

Each of the alternate methods also has certain shortcomings, many of which have been identified by commenters. Basing allowances on historic emissions, for instance, would penalize

States that have already gone through significant efforts to clean up their sources. Basing allowances on heat input has advantages, but cannot accommodate States that have worked to improve their energy efficiency. Basing allowances on output would provide gas-fired units with many more allowances than they need, rather than giving them to the coal-fired units that will be incurring the greatest costs from the tighter caps.

The EPA did look at a number of allowance outcomes using alternate potential methods for allocating SO_2 allowances. These methods included allocating on the basis of historic emissions, heat input (with alternatives based on heat input from all fossil generation, and heat input from coal- and oil-fired generation only) and output (with alternatives based on all generation and all fossil-fired generation). Allocating allowances based on title IV yields results that fall within a reasonable range of results obtained from using these alternate methodologies. In fact, calculating State budgets using title IV allowances yields budgets generally at or within the ranges of budgets calculated using the other methods in more than two-thirds of the States, which account for over 85 percent of the total heat input in the region from 1999–2002. This analysis is discussed further in the response to comments document.

b. Final SO_2 State Emission Budget Methodology

The EPA is finalizing the budgets as noted in the SNPR, adjusting for the proper inclusion of States covered under the final CAIR. The final State budgets are included in Table V–1 below. Details of the data and methodology used to calculate these budgets are included in the accompanying ''Regional and State SO_2 and NO_X Emissions Budgets'' Technical Support Document.

TABLE V–1.—FINAL ANNUAL ELECTRIC GENERATING UNITS SO_2 BUDGETS

[Tons]

State	State SO_2 budget 2010*	State SO_2 budget 2015**
Alabama	157,582	110,307
District of Columbia	708	495
Florida	253,450	177,415
Georgia	213,057	149,140
Illinois	192,671	134,869
Indiana	254,599	178,219
Iowa	64,095	44,866
Kentucky	188,773	132,141
Louisiana	59,948	41,963
Maryland	70,697	49,488
Michigan	178,605	125,024
Minnesota	49,987	34,991
Mississippi	33,763	23,634
Missouri	137,214	96,050
New York	135,139	94,597
North Carolina	137,342	96,139
Ohio	333,520	233,464
Pennsylvania	275,990	193,193
South Carolina	57,271	40,089
Tennessee	137,216	96,051
Texas	320,946	224,662
Virginia	63,478	44,435
West Virginia	215,881	151,117
Wisconsin	87,264	61,085
Total	3,619,196	2,533,434

*Annual budget for SO_2 tons covered by allowances for 2010–2014.
**Annual budget for SO_2 tons covered by allowances for 2015 and thereafter.

c. Use of SO_2 Budgets

These specific levels of the proposed State budgets would actually provide binding statewide caps on EGU emissions for States that choose to control only EGUs but do not want to participate in the trading program. For States choosing to participate in the trading program, these State budgets would not be binding, instead, the States' SO_2 reductions would be achieved solely through the application of required retirement ratios as discussed in section VII of this preamble. For States controlling both EGUs and non-EGUs (or controlling only non-EGUs), these State budgets would be used to calculate the emissions reductions requirements for non-EGUs and the remaining reduction requirement for EGUs. This is described in more detail in the section VII discussion on SIP approvability.

2. NO_X Annual Emissions Budgets

a. Overview

In this section, EPA discusses the apportioning of regionwide NO_X annual emission reduction requirements or budgets to the individual States. In the January 2004 proposal, we proposed State EGU annual NO_X budgets based on each State's average share of recent historic heat input. In the SNPR, we proposed the same input-based methodology, but revised the budgets based on more complete heat input data. Also, EPA took comment on an alternative methodology that determines State budgets by multiplying heat input data by adjustment factors for different fuels. In the August NODA, EPA presented the corrected annual NO_X budgets resulting from the improved methodology proposed in the SNPR.

b. State Annual NO_X Emissions Budget Methodology

Proposed and Discussed NO_X Emission Budget Methodology

As noted elsewhere in today's preamble, EPA determined historical annual heat input data for Acid Rain Program units in the applicable States and multiplied by 0.15 lb/mmBtu (for 2009) and 0.125 lb/mmBtu (for 2015) to determine total annual NO_X regionwide budgets for the CAIR region. The EPA applied these rates to each individual State's total highest annual heat input for any year from 1999 through 2002. Thus, EPA used the heat input total for the year in which a State's total heat input was the highest.

In the January 2004 proposal, we proposed annual NO_X State budgets for a 28-State (and D.C.) region based on each jurisdiction's average heat input—using heat input data from Acid Rain Program units—over the years 1999 through 2002. We summed the average heat input from each of the applicable jurisdictions to obtain a regional total average annual heat input. Then, each State received a pro rata share of the regional NO_X emissions budget based on the ratio of its average annual heat input to the regional total average annual heat input.

In the SNPR, EPA proposed to revise its determination of State NO_X budgets by supplementing Acid Rain Program unit data with annual heat input data from the U.S. Energy Information Administration (EIA), for the non-Acid Rain unit data. A number of commenters had suggested that this would better reflect the heat input of the units that will be controlled under the CAIR, and EPA agrees.

In the SNPR, EPA asked for, and subsequently received, comments on determining State budgets by multiplying heat input data by adjustment factors for different fuels. The factors would reflect the inherently higher emissions rate of coal-fired units, and consequently the greater burden on coal units to control emissions.

Today's Rule

As noted earlier in the case of SO_2, EPA recognizes that the choice of method in setting State budgets, with a given regionwide total annual budget, makes little difference in terms of the levels of resulting regionwide annual

SO_2 and NO_X emissions reductions. If States choose to control EGUs and participate in the cap and trade program, allowances could be freely traded, encouraging least-cost compliance over the entire region. In such a case, the least-cost outcome would not depend on the relative levels of individual State budgets.

A number of commenters have stated, without supporting analysis or evidence, that budgets based on heat input, (and particularly those that would use different fuel factors) do not encourage efficiency. Economic theory indicates that neither a heat input, nor an output-based approach, if allocated once and based on a historical baseline, would provide any incentives for more or less efficient generation (changes in future behavior would have no impact on allocations). The cap and trade system itself, regardless of how the allowances are distributed, provides the primary incentive for more efficient, cleaner generation of electricity.

The EPA is finalizing an approach of calculating State budgets through a fuel-adjusted heat-input basis. State budgets would be determined by multiplying historic heat input data (summed by fuel) by different adjustment factors for the different fuels. These factors reflect for each fuel (coal, gas and oil), the 1999–2002 average emissions by State, summed for the CAIR region, divided by average heat input by fuel by State, summed for the CAIR region. The resulting adjustment factors from this calculation are 1.0 for coal, 0.4 for gas and 0.6 for oil. The factors would reflect the inherently higher emissions rate of coal-fired plants, and consequently the greater burden on coal plants to control emissions.

Such an approach provides States with allowances more in proportion with their historical emissions. It provides for a more equitable budget distribution by recognizing that different States are facing the reduction requirements with different starting stocks of generation, with different starting emission profiles.[88] The fuel burned is a key factor in differentiating the generation.

However, this approach is not equivalent to an approach based strictly on historical emissions (which would give fewer allowances to States which have already cleaned up their coal plants). Under the approach we are finalizing today, heat input from all coal, whether clean or uncontrolled, would be counted equally in determining State budgets. Likewise, all heat input from gas, whether clean or uncontrolled, from a steam-gas unit or from a combined-cycle plant, would be counted equally in determining State budgets.

It is not expected that this decision would disadvantage States with significant gas-fired generation. One reason is that the calculation of the adjusted heat input for natural gas generation generally includes significant historic heat input and emissions from older, less efficient and dirtier steam gas units. These units' capacity factors are declining and are expected to decline further over time as new, cleaner and more efficient combined-cycle gas units increase their generation.

It is important to note that the methodology by which the NO_X State budgets are determined need not be used by individual States in determining allocations to specific sources. As discussed in section VIII of this document (Model Trading Rule), EPA is offering States the flexibility to allocate allowances from their budgets as they see fit.

Finally, EPA discussed in the January 2004 proposal, a methodology used in the NO_X SIP Call (67 FR 21868) that applied State-specific growth rates for heat input in setting State budgets.[89] The EPA, in the SNPR, noted that it is not proposing to use this method for the CAIR because we believe that other methods are reasonable, and that methods involving State-specific growth rates present certain challenges due to the inherent difficulties in predicting State-specific growth in heat input over a lengthy period, especially for jurisdictions that are only a part of a larger regional electric power dispatch region. Several commenters stated their support for incorporating growth, believing that not taking growth into account would penalize States with higher growth. However, a significant number of commenters stated their opposition to using growth in setting State budgets, noting the problems that arose in the NO_X SIP Call. The EPA believes that setting budgets using a heat input approach, without a growth adjustment, is fair, would be simpler and would involve less risk of resulting litigation.

c. Final Annual State NO_X Emission Budgets

The final annual State NO_X emission budgets following this method are included in Table V–2 below. Details of the numbers and methodology used to calculate these budgets are included in the ''Regional and State SO_2 and NO_X Emissions Budgets'' Technical Support Document.

TABLE V–2.—FINAL ANNUAL ELECTRIC GENERATING UNITS NO_X BUDGETS

[Tons]

State	State NO_X budget 2009*	State NO_X budget 2015**
Alabama	69,020	57,517
District of Columbia	144	120
Florida	99,445	82,871
Georgia	66,321	55,268
Illinois	76,230	63,525
Indiana	108,935	90,779
Iowa	32,692	27,243
Kentucky	83,205	69,337
Louisiana	35,512	29,593
Maryland	27,724	23,104
Michigan	65,304	54,420
Minnesota	31,443	26,203
Mississippi	17,807	14,839
Missouri	59,871	49,892
New York	45,617	38,014
North Carolina	62,183	51,819
Ohio	108,667	90,556
Pennsylvania	99,049	82,541
South Carolina	32,662	27,219
Tennessee	50,973	42,478
Texas	181,014	150,845
Virginia	36,074	30,062
West Virginia	74,220	61,850
Wisconsin	40,759	33,966
Total	1,504,871	1,254,061

*Annual budget for NO_X tons covered by allowances for 2009–2014.

**Annual budget for NO_X tons covered by allowances for 2015 and thereafter.

d. Use of Annual NO_X Budgets

These proposed State budgets would serve as effective binding caps on State emissions, if States chose to control only EGUs, but did not want to participate in the trading program. For States controlling both EGUs and non-EGUs (or controlling only non-EGUs), these budgets would be compared to a baseline level of emissions to calculate the emissions reductions requirements for non-EGUs and the required caps for EGUs. This process is described in more detail in the section VII discussion on SIP approvability.

e. NO_X Compliance Supplement Pool

As is discussed in section I, EPA is establishing a NO_X compliance supplement pool of 198,494 tons, which would result in a total compliance supplement pool of approximately 200,000 tons of NO_X when combined with EPA's proposed rulemaking to include Delaware and New Jersey. The

[88] States receiving larger budgets under this approach are generally expected to be those having to make the most reductions.

[89] With a methodology similar to that used in the NO_X SIP Call, annual State NO_X budgets would be set by using a base heat input data, then adjusting it by a calculated growth rate for each jurisdiction's annual EGU heat inputs.

EPA is apportioning the compliance supplement pool to States based on the assumption that a State's need for allowances from the pool is proportional to the magnitude of the State's required emissions reductions (as calculated using the State's base case emissions and annual NO_X budget). The EPA is apportioning the 200,000 tons of NO_X on a pro-rata basis, based on each State's share of the total emissions reductions requirement for the region in 2009. This is consistent with the methodology used in the NO_X SIP Call. Table V–3 presents each State's compliance supplement pool.

TABLE V–3.—STATE NO_X COMPLIANCE SUPPLEMENT POOLS

[Tons]

State	Base case 2009 emissions	2009 State annual NO_X budget	Reduction requirement	Compliance supplement pool *
Alabama	132,019	69,020	62,999	10,166
District of Columbia	0	144	0	0
Florida	151,094	99,445	51,649	8,335
Georgia	143,140	66,321	76,819	12,397
Illinois	146,248	76,230	70,018	11,299
Indiana	233,833	108,935	124,898	20,155
Iowa	75,934	32,692	43,242	6,978
Kentucky	175,754	83,205	92,549	14,935
Louisiana	49,460	35,512	13,948	2,251
Maryland	56,662	27,724	28,938	4,670
Michigan	117,031	65,304	51,727	8,347
Minnesota	71,896	31,443	40,453	6,528
Mississippi	36,807	17,807	19,000	3,066
Missouri	115,916	59,871	56,045	9,044
New York	45,145	45,617	0	0
North Carolina	59,751	62,183	0	0
Ohio	263,814	108,667	155,147	25,037
Pennsylvania	198,255	99,049	99,206	16,009
South Carolina	48,776	32,662	16,114	2,600
Tennessee	106,398	50,973	55,425	8,944
Texas	185,798	181,014	4,784	772
Virginia	67,890	36,074	31,816	5,134
West Virginia	179,125	74,220	104,905	16,929
Wisconsin	71,112	40,759	30,353	4,898
CAIR region subtotal	....	....	....	198,494
Delaware	9,389	4,166	5,223	843
New Jersey	16,760	12,670	4,090	660
Total	....	....	....	199,997

* Rounding to the nearest whole allowance results in a total compliance supplement pool of 199,997 tons.

B. What Is the Approach for Setting State-by-State Emissions Reductions Requirements and EGU Budgets for States With NO_X Ozone Season Reduction Requirements?

1. States Subject to Ozone-Season Requirements

In the NPR, EPA proposed that Connecticut contributes significantly to ozone nonattainment in another State, but not to fine particle nonattainment. As a result of subsequent air quality modeling, EPA has also found that Massachusetts, New Jersey, Delaware and Arkansas contribute significantly to ozone nonattainment in another State, but not to fine particle nonattainment. In this final rule, EPA is establishing a regionwide ozone-season budget for all States that contribute significantly to ozone nonattainment in another State, regardless of their contribution to fine particle nonattainment. The following 25 States, plus the District of Columbia, are found to contribute significantly to ozone nonattainment: Alabama, Arkansas, Connecticut, Delaware, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin.

These States are subject to an ozone season NO_X cap, which covers the 5 months of May through September. The EPA is calculating the ozone season cap level for the 25 States plus the District of Columbia region by multiplying the region's ozone season heat input by 0.15 lb/mmBtu for 2009 and 0.125 lb/mmBtu for 2015. Heat input for the region was estimated by looking at reported ozone season Acid Rain heat inputs for each State for the years 1999 through 2002, and selecting the single year highest heat input for each State as a whole.

As is the case for the annual NO_X State Budgets, EPA is finalizing an approach of calculating ozone season NO_X State budgets through a fuel-adjusted heat input basis. State budgets would be determined by multiplying State-level average historic ozone-season heat input data (summed by fuel) by different adjustment factors for the different fuels (1.0 for coal, 0.4 for gas, and 0.6 for oil). The total ozone season State budgets are then determined by calculating each State's share of total fuel-adjusted heat input, and multiplying this share by the regionwide budget.

The budgets for these States in 2009 and 2015 are included in Table V–4 below.

TABLE V–4.—FINAL SEASONAL ELECTRICITY GENERATING UNIT NO_X BUDGETS

[Tons]

State	State NO_X budget 2009 *	State NO_X budget 2015 **
Alabama	32,182	26,818
Arkansas	11,515	9,596
Connecticut	2,559	2,559
Delaware	2,226	1,855
District of Columbia	112	94
Florida	47,912	39,926
Illinois	30,701	28,981
Indiana	45,952	39,273
Iowa	14,263	11,886
Kentucky	36,045	30,587
Louisiana	17,085	14,238
Maryland	12,834	10,695
Massachusetts	7,551	6,293
Michigan	28,971	24,142
Mississippi	8,714	7,262
Missouri	26,678	22,231
New Jersey	6,654	5,545
New York	20,632	17,193
North Carolina	28,392	23,660
Ohio	45,664	39,945
Pennsylvania	42,171	35,143
South Carolina	15,249	12,707
Tennessee	22,842	19,035
Virginia	15,994	13,328
West Virginia	26,859	26,525
Wisconsin	17,987	14,989
Total	567,744	484,506

* Seasonal budget for NO_X tons covered by allowances for 2009–2014. For States that have lower EGU budgets under the NO_X SIP Call than their 2009 CAIR budget, table V–4 includes their SIP Call budget. For Connecticut, the NO_X SIP Call budget is also used for 2015 and beyond.

** Seasonal budget for NO_X tons covered by allowances for 2015 and thereafter.

VI. Air Quality Modeling Approach and Results

Overview

In this section we summarize the air quality modeling approach used for the proposed rule, we address major comments on the fundamental aspects of EPA's proposed approach, and we describe the updated and improved approach, based on those comments, that we are finalizing today. This section also contains the results of EPA's final air quality modeling, including: (1) Identifying the future baseline $PM_{2.5}$ and 8-hour ozone nonattainment counties in the East; (2) quantifying the contribution from emissions in upwind States to nonattainment in these counties; (3) quantifying the air quality impacts of the CAIR reductions on $PM_{2.5}$ and 8-hour ozone; and (4) describing the impacts on visibility in Class I areas of implementing CAIR compared to implementing the regional haze requirement for best available retrofit technology (BART).

We present the air quality models, model configuration, and evaluation; and then the emissions inventories and meteorological data used as inputs to the air quality models. Next, we provide the updated interstate contributions for $PM_{2.5}$ and 8-hour ozone and those States that make a significant contribution to downwind nonattainment, before considering cost. Finally, we present the estimated impacts of the CAIR emissions reductions on air quality and visibility. As described below, our air quality modeling for today's rule utilizes the Community Multiscale Air Quality (CMAQ) model in conjunction with 2001 meteorological data for simulating $PM_{2.5}$ concentrations and associated visibility effects and the Comprehensive Air Quality Model with Extensions (CAMx) with meteorological data for three episodes in 1995 for simulating 8-hour ozone concentrations. Our approach to modeling both $PM_{2.5}$ and 8-hour ozone involves applying these tools (*i.e.*, CMAQ for $PM_{2.5}$ and CAMx for 8-hour ozone) using updated emissions inventory data for 2001, 2010, and 2015 to project future baseline concentrations, interstate transport, and the impacts of CAIR on projected nonattainment of $PM_{2.5}$ and 8-hour ozone. We provide additional information on the development of our updated CAIR air quality modeling platform, the modeling analysis techniques, model evaluation, and results for $PM_{2.5}$ and 8-hour ozone modeling in the CAIR Notice of Final Rulemaking Emissions Inventory Technical Support Document (NFR EITSD) and the Air Quality Modeling Technical Support Document (NFR AQMTSD).

A. What Air Quality Modeling Platform Did EPA Use?

1. Air Quality Models

a. The $PM_{2.5}$ Air Quality Model and Evaluation

Overview

In the NPR, we used the Regional Model for Simulating Aerosols and Deposition (REMSAD) as the tool for simulating base year and future concentrations of $PM_{2.5}$. Like most photochemical grid models, the predictions of REMSAD are based on a set of atmospheric specie mass continuity equations. This set of equations represents a mass balance in which all of the relevant emissions, transport, diffusion, chemical reactions, and removal processes are expressed in mathematical terms. The modeling domain used for this analysis covers the entire continental United States and adjacent portions of Canada and Mexico.

The EPA applied REMSAD for an annual simulation using meteorology and emissions for 1996. We used the results of this 1996 Base Year model run to evaluate how well the modeling system (*i.e.*, the air quality model and input data sets) replicated measured data over the time period and domain simulated. We performed a model evaluation for $PM_{2.5}$ and speciated components (*e.g.*, sulfate, nitrate, elemental carbon, organic carbon, etc.) as well as nitrate, sulfate and ammonium wet deposition, and visibility. The evaluation used available 1996 ambient measurements paired with REMSAD predictions corresponding to the location and time periods of the measured data. We quantified model performance using various statistical and graphical techniques. Additional information on the model evaluation procedures and results are included in the Notice of Proposed Rulemaking Air Quality Modeling Technical Support Document (NPR AQMTSD).

The EPA received numerous comments on various elements of the proposed $PM_{2.5}$ air quality modeling approach. The major comments are responded to below. Other comments are addressed the Response to Comment (RTC) document. Regarding REMSAD, commenters argued that: (1) The REMSAD model is an inappropriate tool for modeling $PM_{2.5}$; (2) the scientific formulation of the model is simplistic and outdated and that other models with better science are available and should be used; and (3) results from REMSAD are directionally correct but better tools should be used as the basis for the final determinations on transport and projected nonattainment.

We agree that models with more refined science are available for $PM_{2.5}$ modeling and we have selected one of these models, the CMAQ as the tool for $PM_{2.5}$ modeling for the final CAIR. The CMAQ model is a publicly available, peer-reviewed, state-of-the-science model with a number of science attributes that are critical for accurately simulating the oxidant precursors and non-linear organic and inorganic chemical relationships associated with the formation of sulfate, nitrate, and organic aerosols. Several of the important science aspects of CMAQ that are superior to REMSAD include: (1) Updated gaseous/heterogeneous chemistry that provides the basis for the formation of nitrates and includes a current inorganic nitrate partitioning module; (2) in-cloud sulfate chemistry, which accounts for the non-linear sensitivity of sulfate formation to varying pH; (3) a state-of-the-science secondary organic aerosol module that includes a more comprehensive gas-particle partitioning algorithm from both anthropogenic and biogenic secondary organic aerosol; and (4) the full CB–IV chemistry mechanism, which provides a complete simulation of aerosol precursor oxidants.

However, even though REMSAD does not have all the scientific refinements of CMAQ, we believe that REMSAD treats the key physical and chemical processes associated with secondary aerosol formation and transport. Thus, we believe that the conclusions based on the proposal modeling using REMSAD are valid and therefore support today's findings based only on CMAQ that: (1) There will be widespread $PM_{2.5}$ nonattainment in the eastern U.S. in 2010 and 2015 absent the reductions from CAIR; (2) upwind States in the eastern part of the United States contribute to the $PM_{2.5}$ nonattainment problems in other downwind States; (3) States with high emissions tend to contribute more than States with low emissions; (4) States close to nonattainment areas tend to contribute more than other States farther upwind; and (5) the CAIR controls will produce major benefits in terms of bringing areas into or closer to attainment.

Comments and Responses

(i) REMSAD Science and Evaluation

Comment: Some commenters stated that REMSAD is an inappropriate model for use in simulating $PM_{2.5}$. Other commenters said, more specifically, that the chemical mechanism in REMSAD (*i.e.*, micro CB–IV) is simplified and not validated, and that the model has not been scientifically peer-reviewed.

Response: The EPA disagrees with comments claiming that REMSAD is an inappropriate tool for modeling $PM_{2.5}$. The EPA believes that REMSAD is appropriate for regional and national modeling applications because the model does include the key physical and chemical processes associated with secondary aerosol formation and transport.[90]

Specifically, REMSAD simulates both gas phase and aerosol chemistry. The gas phase chemistry uses a reduced-form version of Carbon Bond chemical mechanism (micro-CB–IV). Formation of inorganic secondary particulate species, such as sulfate and nitrate, are simulated through chemical reactions within the model. Aerosol sulfate is formed in both the gas phase and the aqueous phase. The REMSAD model also accounts for the production of secondary organic aerosols through chemistry processes involving volatile organic compounds (VOC) and directly emitted organic particles. Emissions of non-reactive particles (*e.g.*, elemental carbon) are treated as inert species which are advected and deposited during the simulation.

With regard to comments on the micro CB–IV chemical mechanism, although this mechanism treats fewer organic carbon species compared to the full CB–IV, the inorganic portion of the reduced mechanism is identical to the full chemical mechanism. The intent of the CB–IV mechanism is to: (a) Provide a faithful representation of the linkages between emissions of ozone precursor species and secondary aerosol precursor species; (b) treat the oxidizing capacity of the troposphere, represented primarily by the concentrations of radicals and hydrogen peroxide; and (c) simulate the rate of oxidation of the nitrogen oxide (NO_X) and sulfur dioxide (SO_2), which are precursors to secondary aerosols. The EPA agrees that micro CB–IV is simplified compared to the full CB–IV mechanism. However, performance testing of micro CB–IV indicates that this simplified mechanism is similar to the full CB–IV chemical mechanism in simulating ozone formation and approximates other species reasonably well (*e.g.*, hydroxyl radical, hydroperoxy radical, the operator radical, hydrogen peroxide, nitric acid, and peroxyacetyl nitrate).[91]

The REMSAD model was subjected to a scientific peer-review (Seigneur *et al.*, 1999) and EPA has incorporated the major science improvements that were recommended by the peer-review panel. These improvements were included in the version of REMSAD used for the NPR modeling. Specifically, the following updates have been implemented into REMSAD Version 7.06, which was used for the proposed CAIR control strategy simulations: (1) The nighttime chemistry treatment was updated to improve the treatment of the gas phase species NO_3 and N_2O_5; (2) the effects of temperature and pressure dependence on chemical rates were added; (3) the MARS–A aerosol partitioning module was added for calculating particle and gas phase fractions of nitrate; (4) aqueous phase formation of sulfate was updated by including reactions for oxidation of SO_2 by ozone and oxygen, (5) peroxynitric acid (PNA) chemistry was added; and (6) a module for calculating biogenic and anthropogenic secondary organic aerosols was developed and integrated into REMSAD. We believe that these changes adequately respond to the peer review comments and have bolstered the scientific credibility of this model.

(ii) Use of CMAQ Instead of REMSAD for $PM_{2.5}$ Modeling

Comment: Some commenters claimed that REMSAD is outdated and that other models with more sophisticated science are available. Commenters said that EPA should utilize the best available science through use of the most comprehensive photochemical model for simulating aerosols. Commenters specifically stated that EPA should use more recently developed models such as the CMAQ model or the aerosol version of the Comprehensive Air Quality Model with Extensions (CAM_X–PM).

Response: The EPA agrees that photochemical models are now available that are more scientifically sophisticated than REMSAD. In this regard, and in response to commenters' recommendations on specific models, EPA has selected CMAQ as the modeling tool for the final CAIR modeling analysis. As stated above, the CMAQ model is a publicaly available, peer-reviewed, state-of-the-science model with a number of science attributes that are critical for accurately simulating the oxidant precursors and non-linear organic and inorganic chemical relationships associated with the formation of sulfate, nitrate, and organic aerosols. As listed above, the important science aspects of CMAQ that are superior to REMSAD include: (1) Updated gaseous/heterogeneous chemistry that provides the basis for the formation of nitrates and includes a current inorganic nitrate partitioning module; (2) in-cloud sulfate chemistry, which accounts for the non-linear sensitivity of sulfate formation to varying pH; (3) a state-of-the-science secondary organic aerosol module that includes a more comprehensive gas-particle partitioning algorithm from both anthropogenic and biogenic secondary organic aerosol; and (4) the full CB–IV chemistry mechanism, which provides a complete simulation of aerosol precursor oxidants.

(iii) Model Evaluation

Comment: A number of commenters claimed that EPA's air quality model evaluation for 1996 was deficient because it lacked sufficient ambient measurements, especially in urban

[90] Even so, EPA acknowledges that REMSAD has certain limitations not found in CMAQ.

[91] Whitten, G. memorandum: Comparison of REMSAD Reduced Chemistry to Full CB–4. February 19, 2001.

areas, to judge model performance. Commenters said that EPA should: (1) Update the evaluation to a more recent time period in order to take advantage of greatly expanded ambient $PM_{2.5}$ species measurements, especially in urban areas; and (2) calculate model performance statistics over monthly and/or seasonal time periods using daily/weekly observed/model-predicted data pairs.

Some commenters said that the 1996 data were so limited that it is not possible to determine whether REMSAD could be used with confidence to assess the effects of emissions changes. Still, other commenters said that the performance of REMSAD for the 1996 modeling platform was poor.

Commenters acknowledged that there are no universally accepted or EPA-recommended quantitative criteria for judging the acceptability of $PM_{2.5}$ model performance. In the absence of such model performance acceptance criteria, some commenters said that performance should be judged by comparing EPA's model performance results to the range of results obtained by other groups in the air quality modeling community who conducted other recent regional $PM_{2.5}$ model applications. A few commenters also identified specific model performance ranges and criteria that they said should be achievable for sulfate and $PM_{2.5}$, given the current state-of-science for aerosol modeling and measurement uncertainty. The specific values cited by these commenters are ±30 percent to ±50 percent for fractional bias, 50 percent to 75 percent for fractional error, and 50 percent for normalized error.

Response: The EPA agrees that the limited amount of ambient $PM_{2.5}$ species data available in 1996 affected our ability to evaluate model performance, especially in urban areas, and there were deficiencies in the performance of REMSAD using the 1996 model inputs. Also, EPA agrees that a model evaluation should be performed for a more recent time period in order to address these concerns. Thus, we conclude that the 1996 modeling platform which includes 1996 emissions, 1996 meteorology, and 1996 ambient data should be updated and improved, as recommended by commenters.

The EPA has developed a new modeling platform which includes emissions, meteorological data, and other model inputs for 2001. This platform was used to confirm the ability of our modeling system to replicate ambient $PM_{2.5}$ and component species in both urban and rural areas and, thus, establish the credibility of this platform for $PM_{2.5}$ modeling as part of CAIR.[92] In 2001, there was an extensive set of ambient $PM_{2.5}$ measurements including 133 urban Speciation Trends Network (STN) monitoring sites across the nation, with 105 of these in the East. This network did not exist in 1996. Also, the number of mainly suburban and rural monitoring sites in the Clean Air Status and Trends Network (CASTNET) and Interagency Monitoring of Protected Visual Environments (IMPROVE) network has increased to over 200 in 2001, compared to approximately 120 operating in 1996.

The EPA evaluated CMAQ for the 2001 modeling platform using the extensive set of 2001 monitoring data for $PM_{2.5}$ species. The evaluation included a statistical analysis in which the model predictions and measurements were paired in space and in time (*i.e.*, daily or weekly to be consistent with the sampling protocol of the monitoring network). Model performance statistics were calculated for each network with separate statistics for sites in the West and the East.[93] In response to comments that performance statistics should be calculated over monthly and/or seasonal time periods, we elected to use seasonal time periods in order to be consistent with our use of quarterly average $PM_{2.5}$ species as part of the procedure for projecting future concentrations, as described below in section VI.B.1. In addition, the sampling frequency at the CASTNET, IMPROVE, and STN sites may not provide sufficient samples in a 1-month period to provide a robust calculation of model performance statistics. Details of EPA's model evaluation for CMAQ using the 2001 modeling platform are in the report ''Updated CMAQ Model Performance Evaluation for 2001'' which can be found in the docket for today's rule.

The EPA agrees that there are no universally accepted performance criteria for $PM_{2.5}$ modeling and that performance should be judged by comparison to the performance found by other groups in the air quality modeling community. In this respect, we have compared our CMAQ 2001 model performance results to the range of performance found in other recent regional $PM_{2.5}$ model applications by other groups.[94] Details of this comparison can be found in the CMAQ evaluation report. Below is a summary of performance results from other, non-EPA modeling studies, for summer sulfate and winter nitrate. It CAIR. Overall, the general range of fractional bias (FB) and fractional error (FE) statistics for the better performing model applications are as follows:

—Summer sulfate is in the range of −10 percent to +30 percent for FB and 35 percent to 50 percent for FE; and

—Winter nitrate is in the range of +50 percent to +70 percent for FB and 85 percent to 105 percent for FE.

The corresponding performance statistics for EPA's 2001 CMAQ application as well as the 1996 REMSAD application used for the proposal modeling are provided in Table VI–1.

TABLE VI–1.—SELECTED PERFORMANCE EVALUATION STATISTICS FROM THE CMAQ 2001 SIMULATION AND THE REMSAD 1996 SIMULATION

Eastern U.S.	CMAQ 2001		REMSAD 1996	
	FB(%)	FE(%)	FB(%)	FE(%)
Sulfate (Summer):				
STN	14	44	....	....
Improve	10	42	−20	51
CASTNet	3	22	−21	59
Nitrate (Winter)				
STN	15	73	....	....

[92] The 2001 modeling platform is described in full in the NFR EITSD and NFR AQMTSD.

[93] For the purposes of this analysis, we have defined ''East'' as the area to the east of 100 degrees longitude, which runs from approximately the eastern half of Texas through the eastern half of North Dakota.

[94] These other modeling studies represent a wide range of modeling analyses which cover various models, model configurations, domains, years and/or episodes, chemical mechanisms, and aerosol modules.

TABLE VI–1.—SELECTED PERFORMANCE EVALUATION STATISTICS FROM THE CMAQ 2001 SIMULATION AND THE REMSAD 1996 SIMULATION—Continued

Eastern U.S.	CMAQ 2001		REMSAD 1996	
	FB(%)	FE(%)	FB(%)	FE(%)
Improve	21	92	67	103

The results indicate that the performance for CMAQ in 2001 is within the range or better than that found by other groups in recent applications. The performance also meets the benchmark goals suggested by several commenters. In addition, the CMAQ performance is considerably improved over that of the REMSAD 1996 performance for summer sulfate and winter nitrate, which were near the bounds or outside the range of other recent applications.

The CMAQ model performance results give us confidence that our applications of CMAQ using the new modeling platform provide a scientifically credible approach for assessing $PM_{2.5}$ concentrations for the purposes of CAIR.

b. Ozone Air Quality Modeling Platform and Model Evaluation

Overview

The EPA used the CAM_X, version 3.10 in the NPR to assess 8-hour ozone concentrations and the impacts of ozone and ozone precursor transport on elevated levels of ozone across the eastern U.S. The CAM_X is a publicly available Eulerian model that accounts for the processes that are involved in the production, transport, and destruction of ozone over a specified three-dimensional domain and time period. The CAM_X model was run with 1995/96 base year emissions to evaluate the performance of the modeling platform to replicate observed concentrations during the three 1995 episodes. This evaluation was comprised principally of statistical assessments of hourly, 1-hour daily maximum, and 8-hour daily maximum ozone predictions. As described in the NPR AQMTSD, model performance of CAM_X for ozone was judged against the results from previous regional ozone model applications. This analysis indicates that model performance was comparable to or better than that found in previous applications and is, therefore, acceptable for the purposes of CAIR ozone modeling.

The EPA did not receive comments on the CAM_X model or the model performance for ozone. The EPA did receive comments on the choice of episodes for ozone modeling, the meteorological data for these episodes, the spatial resolution of our modeling, and consistency between ozone and $PM_{2.5}$ modeling in terms of methods for projecting future air quality concentrations. As described below and in the RTC document and NFR AQMTSD, we continue to believe that: (1) The three 1995 episodes are representative episodes for regional modeling of 8-hour ozone; and (2) the meteorological data for these episodes and spatial resolution are adequate for use in our modeling for CAIR. Thus, the ozone air quality assessments in today's rule rely on CAM_X modeling of meteorological data for the three 1995 episodes for the domain and spatial resolution used for the NPR. As discussed below, we ran CAM_X for the updated 2001 emissions inventory and the updated 2010 and 2015 base case inventories as part of the process to project 8-hour ozone for these future year scenarios. We revised our method of projecting future ozone concentrations to be consistent with the method we are using for $PM_{2.5}$.

c. Model Grid Cell Configuration

As described in the NPR AQMTSD, the $PM_{2.5}$ modeling for the proposal was performed for a domain (*i.e.*, area) covering the 48 States and adjacent portions of Canada and Mexico. Within this domain, the model predictions were calculated for a grid network with a spatial resolution of approximately 36 km. Our 8-hour ozone modeling for proposal was performed using a nested grid network. The outer portion of this grid has a spatial resolution of approximately 36 km. The inner ''nested'' area, which covers a large portion of the eastern U.S., has a resolution of approximately 12 km.

Comment: Some commenters said that the 36 km grid cell size used by EPA in modeling $PM_{2.5}$ and the 36 km/12 km grid resolution used for ozone modeling are too coarse and are inconsistent with EPA's draft modeling guidance.

Response: We disagree with these comments and continue to believe that the grid dimensions for our $PM_{2.5}$ modeling and our 8-hour ozone modeling are not too coarse nor are they inconsistent with our draft guidance documents for $PM_{2.5}$ modeling [95] and ozone modeling.[96] The draft guidance for $PM_{2.5}$ modeling states that 36 km resolution is acceptable for regional scale applications in portions of the domain outside of nonattainment areas. For portions of the domain which cover nonattainment areas, 12 km resolution or less is recommended by the guidance. However, as stated in the guidance document, these recommendations were based on guidance for 8-hour ozone modeling because there was a lack of $PM_{2.5}$ modeling at different grid resolutions at the time the guidance was drafted. In addition, the $PM_{2.5}$ guidance states that exceptions to these recommendations can be made on a case-by-case basis.

For several reasons, we believe that 36 km resolution is sufficient for $PM_{2.5}$ modeling for the purposes of CAIR. First, recent analyses that compare 36 km to 12 km modeling of $PM_{2.5}$ [97] indicate that spatial mean concentrations of gas phase and aerosol species at 36 km and 12 km are quite similar. A comparison of model predictions versus observations indicates that the model performance is similar at 12 km and 36 km in both rural and urban areas. Thus, using 12 km resolution does not necessarily provide any additional confidence in the results. Second, ambient measurements of sulfate and to a significant extent nitrate, which are the pollutants of most importance for CAIR, do not exhibit large spatial differences between rural and urban areas, as described elsewhere in today's rule. This implies that it is not necessary to use fine resolution modeling in order to properly capture

[95] U.S. EPA, 2000: Draft Guidance for Demonstrating Attainment of the Air Quality Goals for $PM_{2.5}$ and Regional Haze; Draft 1.1, Office of Air Quality Planning and Standards, Research Triangle Park, NC.

[96] U.S. EPA, 1999: Draft Guidance on the Use of Models and Other Analyses in Attainment Demonstrations for the 8-Hour Ozone NAAQS, Office of Air Quality Planning and Standards, Research Triangle Park, NC.

[97] VISTAS Emissions and Air Quality Modeling—Phase I Task 4cd Report: Model Performance Evaluation and Model Sensitivity Tests for Three Phase I Episodes. ENVIRON International Corporation, Alpine Geophysics, and University of California at Riverside, September 7, 2004.

the regional concentration patterns of these pollutants.

Our draft 8-hour ozone modeling guidance recommends using 36 km resolution for regional modeling with nested grid cells not exceeding 12 km over urban portions of the modeling domain. The guidance states that 4 to 5 km resolution for urban areas is preferred, if feasible. In addition, if 12 km modeling is used then plume-in-grid treatment for large point sources of NO_X should be considered.

Our modeling for CAIR is consistent with this guidance in that we use 36 km resolution for the outer portions of the region; 12 km resolution covering nearly all urban areas in the domain; and a plume-in-grid algorithm for major NO_X point sources in the region. In addition, analyses that compare model 12 km resolution to 4 km resolution for portions of our 1995 episodes indicate that the spatial fields predicted at both 12 km and 4 km have many common features in terms of the areas of high and low ozone.[98] In a comparison of model predictions to observation, the 12 km modeling was found to be somewhat more accurate than the finer 4 km modeling.

2. Emissions Inventory Data

For the proposed rule, emissions inventories were created for the 48 contiguous States and the District of Columbia. These inventories were estimated for a 2001 base year to reflect current emissions and for 2010 and 2015 future baseline scenarios. The inventories were prepared for electric generating units (EGUs), industrial and commercial sources (non-EGUs), stationary area sources, on-road vehicles, and non-road engines. The inventories contained both annual and typical summer season day emissions for the following pollutants: oxides of nitrogen (NO_X); volatile organic compounds (VOC); carbon monoxide (CO); sulfur dioxide (SO_2); direct particulate matter with an aerodynamic diameter less than 10 micrometers (PM_{10}) and less than 2.5 micrometers ($PM_{2.5}$); and ammonia (NH_3). A summary of the development of these inventories is provided below. Additional information on the emissions inventory used for proposal can be found in the NPR AQMTSD.

Because the complete 2001 National Emission Inventory (NEI) and future-year projections consistent with that NEI were not available in a form suitable for air quality modeling when needed for the proposal, we developed a reasonably representative ''proxy'' inventory for 2001. For the EGU, mobile, and non-road emissions sectors, 1996-to-2001 adjustment ratios were created by dividing State-level total emissions for each pollutant for 2001 by the corresponding consistent 1996 emissions. These adjustment ratios were then multiplied by the REMSAD-ready 1996 emissions for these two sectors to produce REMSAD-ready files for the 2001 proxy. For non-EGUs and stationary area sources, linear interpolations were performed between the REMSAD-ready 1996 emissions and the REMSAD-ready 2010 base case emissions to produce 2001 proxy emissions for these two sectors. Details on the creation of the 2001 proxy inventory used for proposal are provided in the NPR AQMTSD.

The NPR future 2010 and 2015 base case emissions reflect projected economic growth and control programs that are to be implemented by 2010 and 2015, respectively. Control programs included in these future base cases include those State, local, and Federal measures already promulgated and other significant measures expected to be promulgated before the final rule is implemented. Future year 2010 and 2015 base case EGU emissions were obtained from versions 2.1 and 2.1.6 of the Integrated Planning Model (IPM).

Comment: Several commenters stated that the emission inventory used for the ''proxy'' 2001 base year was not sufficient for the rulemaking, primarily because it was developed from a 1996 modeling inventory by applying various adjustment factors. Commenters suggested that: (1) More up-to-date inventories were now available and should be used; (2) the most recent Continuous Emissions Monitoring (CEM) data or throughput information should be used to derive a 2001 EGU inventory; and (3) EPA should use the 2001 MOBILE6 and NONROAD2002 models for estimating on-road mobile and non-road engine emissions, respectively.

Response: The EPA believes that the base year for modeling should be as recent as possible, given the availability of nationally complete emissions estimates and ambient monitoring data. For the analyses of the final rule, EPA has used a base year inventory developed specifically for 2001. The base year inventory for the electric utility sector now uses measured CEM emissions data for 2001. The non-EGU point source and stationary-area source sectors are based on the final 1999 NEI data submittals from State, local, and Tribal air agencies. This inventory is the latest available quality-assured and reviewed national emission data set for these sectors. The 1999 data for non-EGU point and stationary-area sources were projected to represent a 2001 inventory using State/county-specific and sector-specific growth rates. The on-road mobile inventory uses MOBILE version 6.2 and the non-road engines inventory uses the NONROAD2004 model, both with updated input parameters to calculate emissions for 2001. More detailed information on the development of the emissions inventories can be found in the NFR EITSD.

Comment: Commenters stated that EPA failed to develop an accurate and comprehensive ammonia emission inventory from soil, fertilizer, and animal husbandry sources.

Response: The 2001 inventory used for the analyses for the final rule includes a new national county-level ammonia inventory developed by EPA using the latest emission rates selected based on a comprehensive literature review, and activity levels as provided by the U.S. Census of Agriculture for animal husbandry. The 2001 inventory from fertilizer application sources was compiled from State and local submissions to EPA for 1999, augmented as necessary with EPA estimates, and grown to 2001 using State/county-specific and category-specific growth rates. With regard to background soil emissions of NH_3, EPA believes that the current state of understanding of background soil ammonia releases and sinks is insufficient to warrant including these emission sources in modeling inventories at this time.

Comment: Two commenters indicated that EPA should revise 2010 and 2015 base case emissions by improving the methods for estimating economic growth and not rely on the Bureau of Economic Analysis (BEA) data used for proposal.

Response: In response to these comments, EPA has refined its economic growth projections. In addition to updated versions of the MOBILE6, NONROAD, and IPM models, EPA developed new economic growth rates for stationary, area, and non-EGU point sources. For these two sectors, the final approach uses a combination of: (1) Regional or national fuel-use forecast data from the U.S. Department of Energy for source types that map to fuel use sectors (*e.g.,* commercial coal, industrial natural gas); (2) State-specific growth rates from the Regional Economic Model, Inc. (REMI) Policy Insight® model, version 5.5; and (3) forecasts by

[98] Irwin, J. et al. ''Examination of model predictions at different horizontal grid resolutions.'' Submitted for Publication to Environmental Fluid Mechanics.

specific industry organizations and Federal agencies. For more detail on the growth methodologies, please refer to the NFR EITSD.

3. Meteorological Data

In order to solve for the change in pollutant concentrations over time and space, the air quality model requires certain meteorological inputs that, in part, govern the formation, transport, and destruction of pollutant material. Two separate sets of meteorological inputs were used in the air quality modeling completed as part of the NPR. The meteorological input files for the proposal $PM_{2.5}$ modeling were developed from a Fifth-Generation NCAR/Pennsylvania State Mesoscale Model (MM5) model simulation for the entire year of 1996. The gridded meteorological data for the three 1995 ozone episodes were developed using the Regional Atmospheric Modeling System (RAMS). Both of these models are publicly-available, widely-used, prognostic meteorological models that solve the full set of physical and thermodynamic equations which govern atmospheric motions. Further, each of these specific meteorological data sets has been utilized in past EPA rulemaking modeling analyses (*e.g.,* the Nonroad Land-based Diesel Engines Standards).

Comment: Several commenters claimed that the 1996 meteorological modeling data used to support the fine particulate modeling were outdated and non-representative. We also received recommendations from commenters on benchmarks to be used as goals for judging the adequacy of meteorological modeling.

Response: The EPA draft $PM_{2.5}$ modeling guidance which provides general recommendations on meteorological periods to model for $PM_{2.5}$ purposes lists three primary general criteria for consideration: (a) Variety of meteorological conditions; (b) existence of an extensive air quality/meteorological data bases; and (c) sufficient number of days. The approach recommended in the guidance for modeling annual $PM_{2.5}$ is to use a single, representative year. Based on the comments received and the criteria outlined in the guidance, EPA developed meteorological data for the entire calendar year of 2001. This year was chosen for the $PM_{2.5}$ modeling platform based on several factors, specifically: (a) It corresponds to the most recent set of emissions data; (b) there are considerable ambient $PM_{2.5}$ species data for use in model evaluation (as described in section VI.A.1., above); and (c) Federal Reference Method (FRM) $PM_{2.5}$ data for this year are included in the calculation of the most recent $PM_{2.5}$ design values used for designating $PM_{2.5}$ nonattainment areas. In view of these factors, EPA believes that 2001 meteorology are representative for $PM_{2.5}$ modeling for the purposes of this rule.

The new 2001 meteorological data used for $PM_{2.5}$ modeling were derived from an updated version of the MM5 model used for the 1996 meteorology used for proposal. The version of MM5 used for the 2001 simulation contains more sophisticated physics options with respect to features like cloud microphysics and land-surface interactions, and more refined vertical resolution of the atmosphere compared to the version used for modeling 1996 meteorology. While there are currently no universally accepted criteria for judging the adequacy of meteorological model performance, EPA compared the 2001 MM5 model performance against the benchmark goals [99] recommended by some commenters. The benchmark goals suggest that temperature bias should be within the range of approximately ± 0.5 degrees C and errors less than or equal to 2.0 degrees C are typical.

In general, the model performance statistics for our 2001 meteorological modeling are in line with the above benchmark goals. Specfically, the mean temperature bias of our 2001 meteorological modeling was approximately 0.6 degrees C and the mean error was approximately 2.0 degrees C. The evaluation of the 2001 MM5 for humidity (water vapor mixing ratio) shows biases of less than 0.5 g/kg and errors of approximately 1 g/kg, which compare favorably to the goals of ± 1 g/kg for bias and 2 g/kg or less error. Model performance for winds in our 2001 simulation was also improved compared to what has historically been found in MM5 modeling studies. The index of agreement for surface winds in the 2001 case equaled 0.86, which is far better than the benchmark goal of 0.60. The precipitation evaluation results show that the model generally replicates the observed data, but is overestimating precipitation in the summer months. More information about the model performance evaluation and the MM5 configuration is provided in the NFR AQMTSD.

Comment: Several groups criticized the lack of quantitative meteorological model evaluation data for the 1995 RAMS meteorological modeling used for episodic ozone modeling.

Response: A peer-reviewed, quantitative evaluation of the RAMS model performance for this meteorological period is provided by Hogrefe, *et al.*[100] This analysis was performed using RAMS predictions for June through August of 1995. The results show that the RAMS biases and errors are generally in line with past meteorological model simulations by other groups outside EPA. The EPA remains satisfied that the 1995 RAMS meteorological inputs for the three CAM_X ozone modeling episodes are of sufficient quality and we have continued to use these inputs for the ozone analyses for the final rule.

Comment: The EPA received several comments on the episodes selected for ozone modeling. There was general criticism that the ozone modeling did not follow EPA's own guidance for the selection of episodes. Additionally, there was specific criticism that the episodes did not provide for a reasonable test of the 8-hour ozone NAAQS in some areas.

Response: The draft 8-hour ozone guidance recommends, at a minimum, that four criteria be used to select episodes which are appropriate to model. This guidance is generally intended for local attainment demonstrations, as opposed to regional transport analyses, but it does recommend that in applying a regional model one should choose episodes meeting as many of the criteria as possible, though it acknowledges there may be tradeoffs. Given the large number of nonattainment areas within the ozone domain, it would be extremely difficult to assess the criteria on a area-by-area basis. However, from a general perspective, the 1995 episodes address all of the primary criteria, which include: (1) A variety of meteorological conditions; (2) measured ozone values that are close to current air quality; (3) extensive meteorological and air quality data; and (4) a sufficient number of days. More detail is provided in the NFR AQMTSD, but here is a brief description of how each of the four primary criteria are met by the 1995 cases.

With regard to the criteria of meteorological variations, we have completed inert tracer simulations for each of the three 1995 episodes that show different transport patterns in all three cases. For example the June case involves east-to-west transport; the July case involves west-to-east transport; and

[99] Environ, Enhanced Meteorological Modeling and Performance Evaluation for Two Texas Ozone Episodes. August 2001.

[100] Hogrefe, C. *et al.* ''Evaluating the performance of regional-scale photochemical modeling systems: Part 1-meteorological predictions.'' Atmospherics Environment, vol. 35 (2001), pp. 4159–4174.

the August case involves south-to-north transport. In a separate analysis to determine whether the 1995 modeling days correspond to commonly occurring and ozone-conducive meteorology, EPA has applied a multi-variate statistical approach for characterizing daily meteorological patterns and investigating their relationship to 8-hour ozone concentrations in the eastern U.S. Across the 16 sites for which the analysis was completed, there were five to six distinct sets of meteorological conditions, called regimes, that occurred during the ozone seasons studied. An analysis of the 8-hour daily maximum ozone concentrations for each of the meteorological regimes was undertaken to determine the distribution of ozone concentrations and the frequency of occurrence of each regimes. The EPA determined that between 60 and 70 percent of the episode days we modeled are associated with the most frequently occurring, high ozone potential, meteorological regimes. These results also provide support that the episodes being modeled are representative of conditions present when high ozone concentrations are measured throughout the modeling domain. For the second criteria, EPA has completed an analysis which shows that the 1995 episodes contain observed 8-hour daily maximum ozone values that approximate recent ambient concentrations over the eastern U.S. Additional analyses performed by EPA and others have concluded that each of the three episodes involves widespread areas of elevated ozone concentrations. The synoptic meteorological pattern of the July 1995 episode has been identified by one of the commenters as representing a classic set of conditions necessary for high ozone over the eastern U.S. While the ozone was not quite as widespread in the June and August 1995 episodes, these periods also contained exceedances of the 8-hour ozone NAAQS in most portions of the region.

We believe that there is ample meteorological and air quality data available to support an evaluation of the modeling for these episodes. Specifically, there were over 700 ozone monitors reporting across the domain for use in model evaluation. As noted above, the model performance for these episodes compares favorably to the recommendations in EPA's urban modeling guidance. In addition, the modeling period is comprised of 30 days, not including model ramp-up periods which is considerably more than is typically used in an attainment demonstration modeling submitted to EPA by a State. Finally, EPA's draft ozone guidance also indicates as one of four secondary criteria that extra weight can be assigned to modeling episodes for which there is prior experience in modeling. The 1995 CAIR ozone episodes have been successfully used to drive the air quality modeling completed for several recent notice-and-comment rulemakings (Tier-2, Heavy Duty Engine, and NonRoad). Based on the analyses discussed above and the adherence to the modeling guidance, EPA is satisfied that the 1995 CAM_X episodes are appropriate for continued use.

B. How Did EPA Project Future Nonattainment for $PM_{2.5}$ and 8-Hour Ozone?

1. Projection of Future $PM_{2.5}$ Nonattainment

a. Methodology for Projecting Future $PM_{2.5}$ Nonattainment

In the NPR, we assessed the prospects for future attainment and nonattainment in 2010 and 2015 of the $PM_{2.5}$ annual NAAQS. The approach for identifying areas expected to be nonattainment for $PM_{2.5}$ in the future involved using the model predictions in a relative way to forecast current $PM_{2.5}$ design values to 2010 and 2015. The modeling portion of this approach included annual simulations for 2001 proxy emissions and for 2010 and 2015 base case emissions scenarios. As described below, the predictions from these runs were used to calculate relative reduction factors (RRFs) which were then applied to current $PM_{2.5}$ design values from FRM sites in the East. This approach is consistent with the procedures in the draft of EPA's $PM_{2.5}$ modeling guidance.

To determine the current $PM_{2.5}$ air quality for use in projecting design values to the future, we selected the higher of the 1999–2001 or 2000–2002 design value (the most recent ambient data at the time of the proposal) for each monitor that measured nonattainment in 2000–2002. For those sites that were attaining the $PM_{2.5}$ standard based on their 2000–2002 design value, we used the value from this period as the starting point for projecting 2010 and 2015 air quality at these sites.

The procedure for calculating future year $PM_{2.5}$ design values is called the Speciated Modeled Attainment Test (SMAT). The test uses model predictions in a relative sense to estimate changes expected to occur in each major $PM_{2.5}$ species. These species are sulfate, nitrate, organic carbon, elemental carbon, crustal, and un-attributed mass. The relative change in model-predicted species concentrations were applied to ambient species measurements in order to project each species for the future year scenarios. We applied a spatial interpolation to the IMPROVE and STN speciation data as a means for estimating species composition fractions for the FRM monitoring sites. Future year $PM_{2.5}$ was calculated by summing the projected concentrations of each species. The SMAT technical procedures, as applied for the NPR, are contained in the NPR and NPR AQMTSD.

As noted above, the procedures for determining future year $PM_{2.5}$ concentrations were applied for each FRM site. For counties with only one FRM site, the forecast design value for that site was used to determine whether or not the county was predicted to be nonattainment in the future. For counties with multiple monitoring sites, the site with the highest future concentration was selected for that county. Those counties with future year concentrations of 15.1 $\mu g/m^3$ (as rounded up from 15.05 $\mu g/m^3$) or more were predicted to be nonattainment. Based on the modeling performed for the NPR, 61 counties in the East were forecast to be nonattainment for the 2010 base case. Of these, 41 were forecast to remain nonattainment for the 2015 base case.

Comment: Some commenters said that EPA has not established the credibility of using models in a relative sense to estimate future $PM_{2.5}$ concentrations and that poor performance of REMSAD for 1996 calls into question the use of models to adequately determine the effects of changes in emissions. One commenter said that a mechanistic model evaluation, in which model predictions of $PM_{2.5}$ precursor photochemical oxidants are compared to corresponding measurements, is an approach for gaining confidence in the ability of a model to provide a credible response to emission changes.

Response: The EPA believes the future year nonattainment projections should be based on using model predictions in a relative sense. By applying the model in a relative way, each measured component of $PM_{2.5}$ is adjusted upward or downward based on the percent change in that component, as determined by the ratio of future year to base year model predictions. The EPA feels that by using this approach, we are able to reduce the risk that overprediction or underprediction of $PM_{2.5}$ component species may unduly affect our projection of future year nonattainment.

The EPA agrees with commenters that one way to establish confidence in the credibility of this approach is to determine whether model predictions of $PM_{2.5}$ precursors are generally comparable to corresponding measured data. In this regard, we compared the CMAQ predictions to observations for several precursor gases for which measurements were available in 2001. These gases include sulfur dioxide, nitric acid, and ozone.

The results for the East are summarized in Table VI–2. Additional details on this analysis can be found in the CMAQ evaluation report. The results indicate that for both summer and winter ozone, the fractional bias and error is within the recommended range for urban scale ozone modeling included in EPA's draft guidance for 8-hour ozone modeling. For the other species examined, there are limited ambient data and few other studies against which to compare our findings. Still, our performance results for these species are within the range suggested as acceptable by commenters for sulfate (*i.e.*, ±30 percent to ±60 percent for fractional bias and 50 percent to 75 percent for fractional error). Thus, CMAQ is considered appropriate and credible for use in projecting changes in future year $PM_{2.5}$ concentrations and the resultant health/economic benefits due to the emissions reductions.

TABLE VI–2.—CMAQ MODEL PERFORMANCE STATISTICS FOR OZONE, TOTAL NITRATE, AND NITRIC ACID IN THE EAST

Eastern U.S.	CMAQ 2001	
	FB (%)	FE (%)
Ozone:		
AIRS (Summer)	13	21
AIRS (Winter)	−9	31
Sulfur Dioxide:		
CASTNet (Summer)	31	48
CASTNet (Winter)	39	43
Nitric Acid:		
CASTNet (Summer)	29	39
CASTNet (Winter)	−21	55

Comment: Several commenters said that EPA's SMAT approach is flawed and suggested alternative methods for attributing individual species mass to the FRM measured $PM_{2.5}$ mass. One commenter detailed several different methods to apportion the FRM mass to individual $PM_{2.5}$ species. They refer to two different estimation methods as the ''FRM equivalent'' approach and the ''best estimate'' approach.

Response: The EPA agrees that alternative methodologies can be used to apportion $PM_{2.5}$ species fractions to the FRM data. We believe that revising SMAT to use a methodology similar to an ''FRM equivalent'' methodology, as described in the Notice of Data Availability (69 FR 47828; August 6, 2004), is warranted. Since nonattainment designation determinations and future year nonattainment projections are based on measured FRM data, we believe that the $PM_{2.5}$ species data should be adjusted to best conform to what is measured on the FRM filters. Based on comments, EPA has revised our technique for projecting current $PM_{2.5}$ data to incorporate some aspects of the commenter's ''FRM equivalent'' methodology. As described in more detail in the NFR AQMTSD, we believe our revised methodology to be the most technically appropriate way of estimating what is measured on the FRM filters.

Full documentation of the revised EPA SMAT methodology is contained in the updated SMAT report[101]. In brief, we revised the SMAT methodology to take into account several known differences between what is measured by speciation monitors and what is measured on FRM filters. Among the revisions were calculations to account for nitrate, ammonium, and organic carbon volatilization, blank $PM_{2.5}$ mass, particle bound water, the degree of neutralization of sulfate, and the uncertainty in estimating organic carbon mass.

Comment: Several commenters noted that the future year design values were based on projections of the 1999–2001 and/or 2000–2002 FRM monitoring data and that there are more recent design value data available for the 2001–2003 design value period. Commenters also noted that the 2001–2003 data shows lower $PM_{2.5}$ concentrations at the majority of sites and therefore, by projecting the highest design value, we are overestimating the future year $PM_{2.5}$ values.

Response: As stated above, the $PM_{2.5}$ projection methodology in the NPR used the higher of the 1999–2001 or 2000–2002 $PM_{2.5}$ design value data. The draft modeling guidance for $PM_{2.5}$ specifies the use of the higher of the three design value periods which straddle the emissions year. The emissions year is 2001 and therefore the three periods would be 1999–2001, 2000–2002, and 2001–2003. Since the 2001–2003 data is now available, we are using it as part of the current year $PM_{2.5}$ calculations for the final rule.

The observation by a commenter that the 2001–2003 data are generally lower than in the previous two design value periods (*i.e.*, 1999–2001 and 2000–2002) leads to the issue of how to reduce the influence of year-to-year variability in meteorology and emissions on our estimate of current air quality. As a consequence of this year-to-year variability in concentrations, relying on design values from any single period, as in the approach used for proposal, may not provide a robust representation of current air quality for use in forecasting the future. Specifically, the lower $PM_{2.5}$ values in 2001–2003 may not be representative of the current modeling period. To address the issue of year-to-year variability in the ambient data we have modified our methodology to use an average of the three design value periods that straddle the base year emissions year (*i.e.*, 2001). In this case it is the average of the 1999–2001, 2000–2002, and 2001–2003 design values. The average of the three design values is not a straight 5-year average. Rather, it is a weighted average of the 1999–2003 period. That is, by averaging 1999–2001, 2000–2002, and 2001–2003, the value from 2001 is weighted three times; 2000 and 2002 are each weighted twice and 1999 and 2003 are each weighted once. This approach has the desired benefits of: (1) weighting the $PM_{2.5}$ values towards the middle year of the 5-year period, which is the 2001 base year for

[101] Procedures for Estimating Future $PM_{2.5}$ Values for the CAIR Final Rule by Application of the (Revised) Speciated Modeled Attainment Test (SMAT), docket number OAR–2003–0053–1907.

our emissions projections; and (2) smoothing out the effects of year-to-year variability in emissions and meteorology that occurs over the full 5-year period. We have adopted this method for use in projecting future $PM_{2.5}$ nonattainment for the final rule analysis. We plan to incorporate this new methodology into the next draft version of our $PM_{2.5}$ modeling guidance.

b. Projected 2010 and 2015 Base Case $PM_{2.5}$ Nonattainment Counties

For the final rule, we have revised the projected $PM_{2.5}$ nonattainment counties for 2010 and 2015 by applying CMAQ for the entire year (*i.e.*, January through December) of 2001 using 2001 Base Year and 2010 and 2015 future base case emissions from the new modeling platform, as described in section VI.A.2. The 2010 and 2015 base case $PM_{2.5}$ nonattainment counties were determined applying the updated SMAT method using current 1999–2003 $PM_{2.5}$ air quality coupled with the $PM_{2.5}$ species from the 2001 Base Year and 2010 and 2015 base case CMAQ model runs. For counties with multiple monitoring sites, the site with the highest future concentration was selected for that county. Those counties with future year design values of 15.05 µg/m³ or higher were predicted to be nonattainment. The result is that, without controls beyond those included in the base case, 79 counties in the East are projected to be nonattainment for the 2010 base case. For the 2015 base case, 74 counties in the East are projected to be nonattainment for $PM_{2.5}$.

In light of the uncertainties inherent in regionwide modeling many years into the future, of the 79 nonattainment counties projected for the 2010 base case, we have the most confidence in our projection of nonattainment for those counties that are not only forecast to be nonattainment in 2010, based on the SMAT method, but that also measure nonattainment for the most recent period of available ambient data (*i.e.*, 2001–2003). In our analysis for the 2010 base case, there are 62 such counties in the East that are both ''modeled'' nonattainment and currently have ''monitored'' nonattainment. We refer to these counties as having ''modeled plus monitored'' nonattainment. Out of an abundance of caution, we are using only these 62 ''modeled plus monitored'' counties as the downwind receptors in determining which upwind States make a significant contribution to $PM_{2.5}$ in downwind States.

The 79 counties in the East that we project will be nonattainment for $PM_{2.5}$ in 2010 and the subset of 62 counties that are also ''monitored'' nonattainment in 2001–2003, are identified in Table VI–3. The 2015 base case $PM_{2.5}$ nonattainment counties are provided in Table VI–4.

TABLE VI–3.—PROJECTED $PM_{2.5}$ CONCENTRATIONS (µG/M³) FOR NONATTAINMENT COUNTIES IN THE 2010 BASE CASE

State	County	2010 Base	''Modeled + Monitored''
Alabama	DeKalb Co	15.23	No.
Alabama	Jefferson Co	18.57	Yes.
Alabama	Montgomery Co	15.12	No.
Alabama	Morgan Co	15.29	No.
Alabama	Russell Co	16.17	Yes.
Alabama	Talladega Co	15.34	No.
Delaware	New Castle Co	16.56	Yes.
District of Columbia		15.84	Yes.
Georgia	Bibb Co	16.27	Yes.
Georgia	Clarke Co	16.39	Yes.
Georgia	Clayton Co	17.39	Yes.
Georgia	Cobb Co	16.57	Yes.
Georgia	DeKalb Co	16.75	Yes.
Georgia	Floyd Co	16.87	Yes.
Georgia	Fulton Co	18.02	Yes.
Georgia	Hall Co	15.60	No.
Georgia	Muscogee Co	15.65	No.
Georgia	Richmond Co	15.68	No.
Georgia	Walker Co	15.43	Yes.
Georgia	Washington Co	15.31	No.
Georgia	Wilkinson Co	16.27	No.
Illinois	Cook Co	17.52	Yes.
Illinois	Madison Co	16.66	Yes.
Illinois	St. Clair Co	16.24	Yes.
Indiana	Clark Co	16.51	Yes.
Indiana	Dubois Co	15.73	Yes.
Indiana	Lake Co	17.26	Yes.
Indiana	Marion Co	16.83	Yes.
Indiana	Vanderburgh Co	15.54	Yes.
Kentucky	Boyd Co	15.23	No.
Kentucky	Bullitt Co	15.10	No.
Kentucky	Fayette Co	15.95	Yes.
Kentucky	Jefferson Co	16.71	Yes.
Kentucky	Kenton Co	15.30	No.
Maryland	Anne Arundel Co	15.26	Yes.
Maryland	Baltimore City	16.96	Yes.
Michigan	Wayne Co	19.41	Yes.
Missouri	St. Louis City	15.10	No.
New Jersey	Union Co	15.05	Yes.
New York	New York Co	16.19	Yes.
North Carolina	Catawba Co	15.48	Yes.
North Carolina	Davidson Co	15.76	Yes.
North Carolina	Mecklenburg Co	15.22	No.
Ohio	Butler Co	16.45	Yes.

TABLE VI–3.—PROJECTED $PM_{2.5}$ CONCENTRATIONS (μG/M³) FOR NONATTAINMENT COUNTIES IN THE 2010 BASE CASE—Continued

State	County	2010 Base	"Modeled + Monitored"
Ohio	Cuyahoga Co	18.84	Yes.
Ohio	Franklin Co	16.98	Yes.
Ohio	Hamilton Co	18.23	Yes.
Ohio	Jefferson Co	17.94	Yes.
Ohio	Lawrence Co	16.10	Yes.
Ohio	Mahoning Co	15.39	Yes.
Ohio	Montgomery Co	15.41	Yes.
Ohio	Scioto Co	18.13	Yes.
Ohio	Stark Co	17.14	Yes.
Ohio	Summit Co	16.47	Yes.
Ohio	Trumbull Co	15.28	No.
Pennsylvania	Allegheny Co	20.55	Yes.
Pennsylvania	Beaver Co	15.78	Yes.
Pennsylvania	Berks Co	15.89	Yes.
Pennsylvania	Cambria Co	15.14	Yes.
Pennsylvania	Dauphin Co	15.17	Yes.
Pennsylvania	Delaware Co	15.61	Yes.
Pennsylvania	Lancaster Co	16.55	Yes.
Pennsylvania	Philadelphia Co	16.65	Yes.
Pennsylvania	Washington Co	15.23	Yes.
Pennsylvania	Westmoreland Co	15.16	Yes.
Pennsylvania	York Co	16.49	Yes.
Tennessee	Davidson Co	15.36	No.
Tennessee	Hamilton Co	16.89	Yes.
Tennessee	Knox Co	17.44	Yes.
Tennessee	Sullivan Co	15.32	No.
West Virginia	Berkeley Co	15.69	Yes.
West Virginia	Brooke Co	16.63	Yes.
West Virginia	Cabell Co	17.03	Yes.
West Virginia	Hancock Co	17.06	Yes.
West Virginia	Kanawha Co	17.56	Yes.
West Virginia	Marion Co	15.32	Yes.
West Virginia	Marshall Co	15.81	Yes.
West Virginia	Ohio Co	15.14	Yes.
West Virginia	Wood Co	16.66	Yes.

TABLE VI–4.—PROJECTED $PM_{2.5}$ CONCENTRATIONS (μG/M<>³) FOR NONATTAINMENT COUNTIES IN THE 2015 BASE CASE

State	County	2015 Base
Alabama	DeKalb Co	15.24
Alabama	Jefferson Co	18.85
Alabama	Montgomery Co	15.24
Alabama	Morgan Co	15.26
Alabama	Russell Co	16.10
Alabama	Talladega Co	15.22
Delaware	New Castle Co	16.47
District of Columbia		15.57
Georgia	Bibb Co	16.41
Georgia	Chatham Co	15.06
Georgia	Clarke Co	16.15
Georgia	Clayton Co	17.46
Georgia	Cobb Co	16.51
Georgia	DeKalb Co	16.82
Georgia	Floyd Co	17.33
Georgia	Fulton Co	18.00
Georgia	Hall Co	15.36
Georgia	Muscogee Co	15.58
Georgia	Richmond Co	15.76
Georgia	Walker Co	15.37
Georgia	Washington Co	15.34
Georgia	Wilkinson Co	16.54
Illinois	Cook Co	17.71
Illinois	Madison Co	16.90
Illinois	St. Clair Co	16.49
Illinois	Will Co	15.12
Indiana	Clark Co	16.37
Indiana	Dubois Co	15.66
Indiana	Lake Co	17.27
Indiana	Marion Co	16.77

TABLE VI–4.—PROJECTED $PM_{2.5}$ CONCENTRATIONS (µG/M<>^{3}) FOR NONATTAINMENT COUNTIES IN THE 2015 BASE CASE—Continued

State	County	2015 Base
Indiana	Vanderburgh Co	15.56
Kentucky	Boyd Co	15.06
Kentucky	Fayette Co	15.62
Kentucky	Jefferson Co	16.61
Kentucky	Kenton Co	15.09
Maryland	Baltimore City	17.04
Maryland	Baltimore Co	15.08
Michigan	Wayne Co	19.28
Mississippi	Jones Co	15.18
Missouri	St. Louis City	15.34
New York	New York Co	15.76
North Carolina	Catawba Co	15.19
North Carolina	Davidson Co	15.34
Ohio	Butler Co	16.32
Ohio	Cuyahoga Co	18.60
Ohio	Franklin Co	16.64
Ohio	Hamilton Co	18.03
Ohio	Jefferson Co	17.83
Ohio	Lawrence Co	15.92
Ohio	Mahoning Co	15.13
Ohio	Montgomery Co	15.16
Ohio	Scioto Co	17.92
Ohio	Stark Co	16.86
Ohio	Summit Co	16.14
Ohio	Trumbull Co	15.05
Pennsylvania	Allegheny Co	20.33
Pennsylvania	Beaver Co	15.54
Pennsylvania	Berks Co	15.66
Pennsylvania	Delaware Co	15.52
Pennsylvania	Lancaster Co	16.28
Pennsylvania	Philadelphia Co	16.53
Pennsylvania	York Co	16.22
Tennessee	Davidson Co	15.36
Tennessee	Hamilton Co	16.82
Tennessee	Knox Co	17.34
Tennessee	Shelby Co	15.17
Tennessee	Sullivan Co	15.37
West Virginia	Berkeley Co	15.32
West Virginia	Brooke Co	16.51
West Virginia	Cabell Co	16.86
West Virginia	Hancock Co	16.97
West Virginia	Kanawha Co	17.17
West Virginia	Marshall Co	15.52
West Virginia	Wood Co	16.69

2. Projection of Future 8-Hour Ozone Nonattainment

a. Methodology for Projecting Future 8-Hour Ozone Nonattainment

The approach for projecting future 8-hour ozone concentrations used by EPA in the NPR was based on applying the model in a relative sense to estimate the change in ozone between the base year (2001) and each future scenario. Projected 8-hour ozone design values in 2010 and 2015 were estimated by combining the relative change in model predicted ozone from 2001 to the future scenario with an estimate of the base year ambient 8-hour ozone design value. These procedures for calculating future case ozone design values are consistent with EPA's draft modeling guidance for 8-hour ozone attainment demonstrations. The draft guidance specifies the use of the higher of the design values from (a) the period that straddles the emissions inventory base year or (b) the design value period which was used to designate the area under the ozone NAAQS. At the time of the proposal, 2000–2002 was the design value period which both straddled the 2001 base year inventory and was also the latest period available.

Comment: Commenters noted that the procedures used by EPA for projecting future 8-hour ozone concentrations differ from the procedures used for projecting $PM_{2.5}$. These commenters said that EPA should harmonize the two approaches.

Response: In response to comments, we have made several changes in the approach to projecting future 8-hour ozone nonattainment in order to follow an approach that is consistent with the manner in which $PM_{2.5}$ projections are determined. The approach we are using to project $PM_{2.5}$ for the final rule analysis is described in section VI.B.1, above. In order to harmonize the ozone approach with the approach used for $PM_{2.5}$, we are using the weighted average of the design values for the periods that straddle the emission base year (*i.e.*, 2001). These periods are 1999–2001, 2000–2002, and 2001–2003. In this approach, the fourth-high ozone value from 2001 is weighted three times, 2000 and 2002 are weighted twice, and 1999 and 2003 are weighted once. This has the desired effect of weighting the projected ozone values towards the middle year of the 5-year period, which is the emissions year (2001), while accounting for the emissions and meteorological variability that occurs over the full 5-year period. The average weighted concentration is expected to be more representative as a starting point for future year projections than choosing (a) the single design value period that straddles the base year or (b) the design value used for designations. We plan to incorporate this new methodology into the next draft version of our ozone modeling guidance.

Comment: One commenter claimed that the 2010 and 2015 ozone projections in the proposal base cases were too optimistic, that is, that the modeling was underestimating the number of areas that may be in nonattainment in the future. The commenter urged a more conservative approach to assessing the future attainment status of areas.

Response: The technical basis for the comment stemmed from the assertion that the regional ozone modeling that EPA performed for the proposal was not of ''SIP-quality.'' The EPA response to the specific technical issues with regard to episode selection and grid resolution can be found in section VI.A as well as in the response to comments document. The EPA remains confident that the CAIR 8-hour ozone modeling platform is appropriate for assessing potential levels of future nonattainment.

b. Projected 2010 and 2015 Base Case 8-Hour Ozone Nonattainment Counties

For the final rule, we have revised our projections of ozone nonattainment for the 2010 and 2015 base cases by applying CAMx for the three 1995 ozone episodes using 2001 Base Year and 2010 and 2015 future base case emissions from the new modeling platform, as described in section VI.A.2. The revised 2010 and 2015 base case 8-hour ozone nonattainment counties were determined by applying the relative change in 8-hour ozone predicted by these CAMx model runs to the weighted average 1999–2003 8-hour ozone concentrations as described above and, in more detail, in the NFR AQMTSD. For counties with multiple monitoring sites, the site with the highest future concentration was selected for that county. Those counties with future year design values of 85 parts per billion (ppb) or higher were predicted to be nonattainment.

As a result of our updated modeling we project that, without controls beyond those in the base case, there will be 40 8-hour ozone nonattainnment counties in 2010 and 22 nonattainment counties in 2015. All of the 40 counties that we are projecting to be nonattainment for the 2010 base case are also measuring nonattainment based on the most recent design value period (*i.e.*, 2001–2003). We refer to these counties as ''modeled plus monitored'' nonattainment, as described above in section IV.B.1 for $PM_{2.5.}$ We are using these 40 counties as the downwind receptors to determine which States make a significant contribution to 8-hour ozone nonattainment in downwind States.

The counties we are projecting to be nonattainment for 8-hour ozone in the 2010 base case and 2015 base case are listed in Table VI–5 and Table VI–6, respectively.

TABLE VI–5.—PROJECTED 2010 BASE CASE 8-HOUR OZONE NONATTAINMENT COUNTIES AND CONCENTRATIONS (PPB)

State	County	2010 Base
Connecticut	Fairfield Co	92.6
Connecticut	Middlesex Co	90.9
Connecticut	New Haven Co	91.6
Delaware	New Castle Co	85.0
District of Columbia		85.2
Georgia	Fulton Co	86.5
Maryland	Anne Arundel Co	88.8
Maryland	Cecil Co	89.7
Maryland	Harford Co	93.0
Maryland	Kent Co	86.2
Michigan	Macomb Co	85.5
New Jersey	Bergen Co	86.9
New Jersey	Camden Co	91.9
New Jersey	Gloucester Co	91.8
New Jersey	Hunterdon Co	89.0
New Jersey	Mercer Co	95.6
New Jersey	Middlesex Co	92.4
New Jersey	Monmouth Co	86.6
New Jersey	Morris Co	86.5
New Jersey	Ocean Co	100.5
New York	Erie Co	87.3
New York	Richmond Co	87.3
New York	Suffolk Co	91.1
New York	Westchester Co	85.3
Ohio	Geauga Co	87.1
Pennsylvania	Bucks Co	94.7
Pennsylvania	Chester Co	85.7
Pennsylvania	Montgomery Co	88.0
Pennsylvania	Philadelphia Co	90.3
Rhode Island	Kent Co	86.4
Texas	Denton Co	87.4
Texas	Galveston Co	85.1
Texas	Harris Co	97.9
Texas	Jefferson Co	85.6
Texas	Tarrant Co	87.8
Virginia	Arlington Co	86.2
Virginia	Fairfax Co	85.7
Wisconsin	Kenosha Co	91.3
Wisconsin	Ozaukee Co	86.2

TABLE VI–5.—PROJECTED 2010 BASE CASE 8-HOUR OZONE NONATTAINMENT COUNTIES AND CONCENTRATIONS (PPB)—Continued

State	County	2010 Base
Wisconsin	Sheboygan Co	88.3

TABLE VI–6.—PROJECTED 2015 BASE CASE 8-HOUR OZONE NONATTAINMENT COUNTIES AND CONCENTRATIONS (PPB)

State	County	2015 Base
Connecticut	Fairfield Co	91.4
Connecticut	Middlesex Co	89.1
Connecticut	New Haven Co	89.8
Maryland	Anne Arundel Co	86.0
Maryland	Cecil Co	86.9
Maryland	Harford Co	90.6
Michigan	Macomb Co	85.1
New Jersey	Bergen Co	85.7
New Jersey	Camden Co	89.5
New Jersey	Gloucester Co	89.6
New Jersey	Hunterdon Co	86.5
New Jersey	Mercer Co	93.5
New Jersey	Middlesex Co	89.8
New Jersey	Ocean Co	98.0
New York	Erie Co	85.2
New York	Suffolk Co	89.9
Pennsylvania	Bucks Co	93.0
Pennsylvania	Montgomery Co	86.5
Pennsylvania	Philadelphia Co	88.9
Texas	Harris Co	97.3
Texas	Jefferson Co	85.0
Wisconsin	Kenosha Co	89.4

C. How Did EPA Assess Interstate Contributions to Nonattainment?

1. $PM_{2.5}$ Contribution Modeling Approach

For the proposed rule, EPA performed State-by-State zero-out modeling to quantify the contribution from emissions in each State to future $PM_{2.5}$ nonattainment in other States and to determine whether that contribution meets the air quality prong (*i.e.*, before considering cost) of the ''contribute significantly'' test. The zero-out modeling technique provides an estimate of downwind impacts by comparing the model predictions from the 2010 base case to the predictions from a run in which all anthropogenic SO_2 and NO_X emissions are removed from specific States. Counties forecast to be nonattainment for $PM_{2.5}$ in the proposal 2010 base case were used as receptors for quantifying interstate contributions of $PM_{2.5}$. For each State-by-State zero-out run we projected the annual average $PM_{2.5}$ concentration at each receptor using the proposed SMAT technique, as described in the NPR AQMTSD. The contribution from an upwind State to nonattainment at a given downwind receptor was determined by calculating the difference in $PM_{2.5}$ concentration between the 2010 base case and the zero-out run at that receptor. We followed this process for each State-by-State zero-out run and each receptor. For each upwind State, we identified the largest contribution from that State to a downwind nonattainment receptor in order to determine the magnitude of the maximum downwind contribution from each State. The maximum downwind contribution was proposed as the metric for determining whether or not the contribution was significant. As described in section III, EPA proposed, in the alternative, a criterion of 0.10 $\mu g/m^3$ and 0.15 $\mu g/m^3$ for determining whether emissions in a State make a significant contribution (before considering cost) to $PM_{2.5}$ nonattainment in another State. Details on these procedures can be found in the NPR AQMTSD.

Comments: Commenters questioned the use of zero-out modeling and said that EPA should support the development of a source apportionment model for $PM_{2.5}$ contributions. The commenter recommended that EPA delay the final rule until such a technique can be used. Another commenter provided results of a sulfate source apportionment technique currently under development along with modeling results which showed that the zero-out technique and source apportionment for sulfate provide similar results in terms of the magnitude and extent of downwind impacts. The commenter noted that the results suggest that zero-out modeling may somewhat underestimate the transport of sulfate.

Response: The EPA continues to believe that the zero-out technique is a credible method for quantifying interstate $PM_{2.5}$ contributions. This is supported by a commenter's results showing that the zero-out technique and source apportionment appear to give similar results. We accept the commenter's modeling for sulfate source apportionment results which indicate that the zero-out technique does not overestimate interstate transport. Moreover, EPA rejects the notion that we should delay needed reductions while we await alternative assessment techniques.

2. 8-Hour Ozone Contribution Modeling Approach

In the proposal, EPA quantified the impact of emissions from specific upwind States on 8-hour ozone concentrations in projected downwind nonattainment areas. The procedures we followed to assess interstate ozone contribution for the proposal analysis are summarized below. We are using these same procedures along with the updated CAM_X modeling platform, as described in section VI.A., to assess ozone contributions for today's rule. Details on these procedures can be found in the NFR AQMTSD.

We applied two different modeling techniques, zero-out and source apportionment, to assess the contributions of emissions in upwind States on 8-hour ozone nonattainment in downwind States. The outputs of the two modeling techniques were evaluated in terms of three key contribution factors to determine which States make a significant contribution to downwind ozone nonattainment as described in section VI.B.2. The zero-out and source apportionment modeling techniques provide different, but equally valid, technical approaches to quantifying the downwind impact of emissions from upwind States. The zero-out modeling analysis provides an estimate of downwind impacts by comparing the model predictions from the 2010 base case and the predictions from a model run in which all anthropogenic NO_X and VOC emissions are removed from specific States. The source apportionment modeling quantifies downwind impacts by tracking and allocating the amounts of ozone formed from man-made NO_X and VOC emissions in upwind States. Because large portions of the six States along the western border of the modeling domain [102] are outside the area covered by our modeling, EPA did not analyze the contributions to downwind ozone nonattainment for these States.

In the analysis done at proposal, EPA considered three fundamental factors for evaluating whether emissions in an upwind State make large and/or frequent contributions to downwind nonattainment: (1) The magnitude of the contribution; (2) the frequency of the contribution; and (3) the relative amount of the contribution when compared against contributions from other areas. The factors are the basis for several metrics that can be used to assess a particular impact. The metrics used in this analysis were the same as those used in the NO_X SIP Call.

Within these three factors, eight specific metrics were calculated to assess the contribution of each of the 31 States to the residual nonattainment counties. For the zero-out modeling, EPA considered: (1) The maximum contribution (magnitude); (2) the number and percentage of exceedances with contributions in certain concentration ranges (frequency); (3) the total contribution relative to the total exceedance level ozone in the receptor area (relative amount); and (4) the population-weighted total contribution relative to the total population-weighted exceedance level ozone in the receptor area (relative amount). For the source apportionment modeling EPA considered: (5) The maximum contribution (magnitude); (6) the highest daily average contribution (magnitude); (7) the number and percentages of exceedances with contributions in certain concentration ranges (frequency); and (8) the total average contribution to exceedance ozone in the downwind area (relative amount). The values for these metrics were calculated using only those periods during which the model predicted 8-hour average ozone concentrations greater than or equal to 85 ppb in at least one of the model grid cells associated with the receptor county in the 2010 base case. Grid cells were linked to a specific nonattainment county if any part of the grid cell covered any portion of the projected 2010 nonattainment county.

The first step in evaluating the contribution factors was to screen out linkages for which the contributions were clearly small. This initial screening was based on two criteria: (1) The maximum contribution had to be greater than or equal to 2 ppb from either of the two modeling techniques; and (2) the total average contribution to exceedance of ozone in the downwind area had to be greater than 1 percent. If either screening test was not met, then the linkage was not considered significant. Those linkages that had contributions which exceeded the screening criteria were evaluated further in steps 2 through 4.

In step 2, we evaluated the contributions in each linkage based on the zero-out modeling and in step 3 we evaluated the contributions in each linkage based on the source apportionment modeling. In step 4, we considered the results of both step 2 and step 3 to determine which of the linkages were significant. For both techniques, EPA determined whether the linkage is significant by evaluating the magnitude, frequency, and relative amount of the contributions. Each upwind State that made relatively large and/or frequent contributions to nonattainment in the downwind area, based on these factors, was considered to contribute significantly to nonattainment in the downwind area.

The EPA believes that each of the factors provides an independent measure of contribution, however, there had to be at least two different factors that indicated large and/or frequent contributions in order for the linkage to be found significant. In this regard, the finding of a significant contribution for an individual linkage was not based on any single factor. Further, each of the modeling approaches had to show at least one indicator of a large and/or frequent contribution in order for the linkage to be found significant. The EPA received several general comments on the procedures for assessing interstate contributions of ozone to projected residual nonattainment areas, as discussed below.

Comment: A commenter opposed the use of population-weighted metrics to determine whether an upwind State's impact on a location in another State is significant.

Response: The commenter's concern was that transport contributions to rural areas with low populations were not being weighted appropriately. This is not a valid concern because the relative contribution factor from the zero-out modeling is presumed to be met if either of the two criteria (population-weighted, or non-population-weighted) show large contributions.

Comment: Also, EPA received a specific comment on a certain linkage that was deemed to be significant in the analysis done to support the NPR. The commenter objected to the conclusion that Mississippi significantly contributes to residual ozone exceedances near Memphis. The objection resulted from issues with grid resolution, episode selection, and the fact that the zero-out and source apportionment modeling for Mississippi included some emissions from Tennessee and Arkansas due to the irregular State boundaries.

Response: As noted in section VI.B.2, Crittenden County, AR is no longer projected to be a nonattainment area in the 2010 base case. As a result, the issue of Mississippi's contribution to ozone in the Memphis area is moot.

D. What Are the Estimated Interstate Contributions to $PM_{2.5}$ and 8-Hour Ozone Nonattainment?

1. Results of $PM_{2.5}$ Contribution Modeling

In this section, we present the interstate contributions from emissions in upwind States to $PM_{2.5}$ nonattainment in downwind nonattainment counties. States which contribute 0.2 $\mu g/m^3$ or more to $PM_{2.5}$ nonattainment in another State are determined to contribute significantly (before considering cost). We calculated the interstate $PM_{2.5}$ contributions using the State-by-State zero-out modeling technique, as indicated above in section VI.C.1. This technique is described in

[102] The six States are Kansas, Nebraska, North Dakota, Oklahoma, South Dakota, and Texas.

the NFR AQMTSD. We performed zero-out modeling using CMAQ for each of 37 States individually (*i.e.*, Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland combined with the District of Columbia, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Nebraska, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Vermont, Virginia, West Virginia, and Wisconsin).

We calculated each State's contribution to $PM_{2.5}$ in each of the 62 counties that are projected to be nonattainment in the 2010 base case (*i.e.*, ''modeled'' nonattainment) and are also ''monitored'' nonattainment in 2001–2003, as described in section VI.B.1.b. The maximum contribution from each upwind State to downwind $PM_{2.5}$ nonattainment is provided in Table VI–7. The contributions from each State to nonattainment in each nonattainment county are provided in the NFR AQMTSD. Based on the State-by-State modeling, there are 23 States and the District of Columbia [103] which contribute 0.2 μg/m³ or more to downwind $PM_{2.5}$ nonattainment (Alabama, the District of Columbia, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin). In Table VI–8, we provide a list of the downwind nonattainment counties to which each upwind State contributes 0.2 μg/m³ or more (*i.e.*, the upwind State-to-downwind nonattainment ''linkages'').

TABLE VI–7.—MAXIMUM DOWNWIND $PM_{2.5}$ CONTRIBUTION (μG/M³) FOR EACH OF 37 STATES

Upwind State	Maximum downwind contribution
Alabama	0.98
Arkansas	0.19
Connecticut	<0.05
Delaware	0.14
Florida	0.45
Georgia	1.27
Illinois	1.02
Indiana	0.91
Iowa	0.28
Kansas	0.11
Kentucky	0.90
Louisiana	0.25
Maine	<0.05
Maryland/DC	0.69
Massachusetts	0.07
Michigan	0.62
Minnesota	0.21
Mississippi	0.23
Missouri	1.07
Nebraska	0.07
New Hampshire	<0.05
New Jersey	0.13
New York	0.34
North Carolina	0.31
North Dakota	0.11
Ohio	1.67
Oklahoma	0.12
Pennsylvania	0.89
Rhode Island	<0.05
South Carolina	0.40
South Dakota	<0.05
Tennessee	0.65
Texas	0.29
Vermont	<0.05
Virginia	0.44
West Virginia	0.84
Wisconsin	0.56

TABLE VI–8.—UPWIND STATE-TO-DOWNWIND NONATTAINMENT COUNTY SIGNIFICANT ''LINKAGES'' FOR $PM_{2.5}$.

Upwind states	Total linkages	Downwind counties			
AL	21	Bibb GA	Cabell WV	Catawba NC	Clark IN.
		Clarke GA	Clayton GA	Cobb GA	Davidson NC.
		DeKalb GA	Dubois IN	Fayette KY	Floyd GA.
		Fulton GA	Hamilton OH	Hamilton TN	Jefferson KY.
		Knox TN	Lawrence OH	Scioto OH	Vanderburgh IN.
		Walker GA.			
FL	7	Bibb GA	Clarke GA	Clayton GA	Cobb GA.
		DeKalb GA	Jefferson AL	Russell AL.	
GA	17	Butler OH	Cabell WV	Catawba NC	Clark IN.
		Davidson NC	Fayette KY	Hamilton OH	Hamilton TN.
		Jefferson AL	Jefferson KY	Kanawha WV	Knox TN.
		Lawrence OH	Montgomery OH	Russell AL	Scioto OH.
		Vanderburgh IN.			
IL	23	Allegheny PA	Butler OH	Cabell WV	Clark IN.
		Cuyahoga OH	Dubois IN	Fayette KY	Franklin OH.
		Hamilton OH	Hamilton TN	Jefferson AL	Jefferson KY.
		Kanawha WV	Lake IN	Lawrence OH	Mahoning OH.
		Marion IN	Montgomery OH	Scioto OH	Stark OH.
		Summit OH	Vanderburgh IN	Wayne MI	
IN	46	Allegheny PA	Beaver PA	Berkeley WV	Bibb GA.
		Brooke WV	Butler OH	Cabell WV	Cambria PA.
		Catawba NC	Clarke GA	Clayton GA	Cobb GA.
		Cook IL	Cuyahoga OH	Davidson NC	DeKalb GA.
		Fayette KY	Floyd GA	Franklin OH	Fulton GA.
		Hamilton OH	Hamilton TN	Hancock WV	Jefferson AL.
		Jefferson KY	Jefferson OH	Kanawha WV	Knox TN.

[103] As noted above, we combined Maryland and the District of Columbia as a single entity in our contribution modeling. This is a logical approach because of the small size of the District of Columbia and, hence, its emissions and its close proximity to Maryland. Under our analysis, Maryland and the District of Columbia are linked as significant contributors to the same downwind nonattainment counties. The EPA received no adverse comment on this approach. We also considered these entities separately, and in view of the close proximity of these two areas we believe that Maryland is linked as a significant contributor to nonattainment in the District of Columbia and that the District of Columbia is linked as a significant contributor to nonattainment in Maryland.

TABLE VI–8.—UPWIND STATE-TO-DOWNWIND NONATTAINMENT COUNTY SIGNIFICANT "LINKAGES" FOR $PM_{2.5}$.—Continued

		Lancaster PA	Lawrence OH	Madison IL	Mahoning OH.
		Marion WV	Marshall WV	Montgomery OH	Ohio WV.
		Russell AL	St. Clair IL	Scioto OH	Stark OH.
		Summit OH	Walker GA	Wayne MI	Washington PA.
		Westmoreland PA	Wood WV.		
IA	5	Cook IL	Lake IN	Madison IL	Marion IN.
		St. Clair IL.			
KY	35	Allegheny PA	Butler OH	Cabell WV	Catawba NC.
		Clark IN	Clarke GA	Cobb GA	Cuyahoga OH.
		Davidson NC	Dubois IN	Floyd GA	Franklin OH.
		Hamilton OH	Hamilton TN	Jefferson AL	Jefferson OH.
		Kanawha WV	Knox TN	Lawrence OH	Madison IL.
		Mahoning OH	Marion IN	Marion WV	Marshall WV.
		Montgomery OH	Ohio WV	St. Clair IL	Scioto OH.
		Stark OH	Summit OH	Vanderburgh IN	Walker GA.
		Washington PA	Westmoreland PA	Wood WV..	
LA	2	Jefferson AL	Russell AL.		
MD/DC	13	Berkeley WV	Berks PA	Cambria PA	Dauphin PA.
		Delaware PA	District of Columbia	Lancaster PA	New Castle DE.
		New York NY	Philadelphia PA	Union NJ	Westmoreland PA.
		York PA.			
MI	36	Allegheny PA	Beaver PA	Berks PA	Brooke WV.
		Butler OH	Cabell WV	Cambria PA	Clark IN.
		Cook IL	Cuyahoga OH	Dauphin PA	Delaware PA.
		Fayette KY	Franklin OH	Hamilton OH	Hancock WV.
		Jefferson OH	Lake IN	Lancaster PA	Lawrence OH.
		Mahoning OH	Marion IN	Marion WV	Marshall WV.
		Montgomery OH	New Castle DE	Ohio WV	Philadelphia PA.
		Scioto OH	Stark OH	Summit OH	Union NJ.
		Washington PA	Westmoreland PA	Wood WV	York PA.
MN	2	Cook IL	Lake IN.		
MO	9	Clark IN	Cook IL	Dubois IN	Jefferson KY.
		Lake IN	Madison IL	Marion IN	St. Clair IL.
		Vanderburgh IN..			
MS	1	Jefferson AL.			
NY	5	Berks PA	Lancaster PA	New Castle DE	New Haven CT.
		Union NJ.			
NC	7	Anne Arundel MD	Baltimore City	Bibb GA	Clarke GA.
		District of Columbia	Kanawha WV	Knox TN..	
OH	51	Anne Arundel MD	Allegheny PA	Baltimore City MD	Beaver PA.
		Berkeley WV	Berks PA	Bibb GA	Brooke WV.
		Cabell WV	Cambria PA	Catawba NC	Clark IN.
		Clarke GA	Clayton GA	Cobb GA	Cook IL.
		Dauphin PA	Davidson NC	DeKalb GA	Delaware PA.
		District of Columbia	Dubois IN	Fayette KY	Floyd GA.
		Fulton GA	Hamilton TN	Hancock WV	Jefferson AL.
		Jefferson KY	Kanawha WV	Knox TN	Lake IN.
		Lancaster PA	Madison IL	Marion IN	Marion WV.
		Marshall WV	New Castle DE	New York NY	Ohio WV.
		Philadelphia PA	Russell AL	St. Clair IL	Union NJ.
		Vanderburgh IN	Walker GA	Washington PA	Wayne MI.
		Westmoreland PA	Wood WV	York PA.	
PA	25	Anne Arundel MD	Baltimore City	Berkeley WV	Brooke WV.
		Cabell WV	Catawba NC	Clarke GA	Cuyahoga OH.
		Davidson NC	District of Columbia	Hancock WV	Jefferson OH.
		Kanawha WV	Lawrence OH	Mahoning OH	Marion WV.
		Marshall WV	New Castle DE	New York NY	Ohio WV.
		Stark OH	Summit OH	Union NJ	Wayne MI.
		Wood WV.			
SC	9	Bibb GA	Catawba NC	Clarke GA	Clayton GA.
		Cobb GA	Davidson NC	DeKalb GA	Fulton GA.
		Russell AL.			
TN	23	Bibb GA	Butler OH	Cabell WV	Catawba NC.
		Clark IN	Clarke GA	Clayton GA	Cobb GA.
		Davidson NC	DeKalb GA	Dubois IN	Fayette KY.
		Floyd GA	Fulton GA	Hamilton OH	Jefferson AL.
		Jefferson KY	Kanawha WV	Lawrence OH	Russell AL.
		Scioto OH	Vanderburgh TN	Walker GA.	
TX	2	Madison IL	St Clair IL.		
VA	13	Anne Arundel MD	Baltimore City MD	Berkeley WV	Berks PA.
		Catawba NC	Dauphin PA	Davidson NC	Delaware PA.
		District of Columbia	Lancaster PA	New Castle DE	Philadelphia PA.

TABLE VI–8.—UPWIND STATE-TO-DOWNWIND NONATTAINMENT COUNTY SIGNIFICANT "LINKAGES" FOR $PM_{2.5}$.—Continued

		York PA.			
WV	33	Anne Arundel MD	Allegheny PA	Baltimore City MD	Beaver PA.
		Berks PA	Butler OH	Cambria PA	Catawba NC.
		Clarke GA	Cuyahoga OH	Dauphin PA	Davidson NC.
		Delaware PA	District of Columbia	Fayette KY	Franklin OH.
		Hamilton OH	Jefferson OH	Knox TN	Lancaster PA.
		Lawrence OH	Mahoning OH	Montgomery OH	New Castle DE.
		New York NY	Philadelphia PA	Scioto OH	Stark OH.
		Summit OH	Union NJ	Washington PA	Westmoreland PA.
		York PA.			
WI	4	Cook IL	Lake IN	Marion IN	Wayne MI.

2. Results of 8-Hour Ozone Contribution Modeling

In this section, we present the results of air quality modeling to determine which upwind States contribute significantly (before considering cost) to 8-hour ozone nonattainment in downwind States. The analytical procedures to determine which States make a significant contribution are based on the zero-out and source apportionment modeling techniques using CAM_X, as described in section VI.C.2 and in the NFR AQMTSD. We performed ozone contribution modeling using both of these techniques for 31 States in the East and the District of Columbia (*i.e.*, Alabama, Arkansas, Connecticut, Delaware, Georgia, Florida, Iowa, Illinois, Indiana, Kentucky, Louisiana, Massachusetts, Maine, Maryland combined with the District of Columbia, Michigan, Minnesota, Mississippi, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Vermont, Virginia, West Virginia, and Wisconsin).

We evaluated the interstate ozone contributions from each of the 31 upwind States and the District of Columbia to each of the 40 counties that are projected to be nonattainment in the 2010 base case (*i.e.*, "modeled" nonattainment) and are also "monitored" nonattainment in 2001–2003, as described in section VI.B.2.b. We analyzed the contributions from upwind States to these counties in terms of various metrics, described above and in more detail in the NFR AQMTSD.

Based on the State-by-State modeling, there are 25 States and the District of Columbia [104] which make a significant contribution (before considering cost) to 8-hour ozone nonattainment in downwind States (*i.e.*, Alabama, Arkansas, Connecticut, Delaware, the District of Columbia, Florida, Iowa, Illinois, Indiana, Kentucky, Louisiana, Massachusetts, Maryland, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin). In Table VI–9, we provide a list of the downwind nonattainment counties to which each upwind State makes a significant contribution (*i.e.*, the upwind State-to-downwind nonattainment "linkages").

TABLE VI–9.—UPWIND STATE-TO-DOWNWIND NONATTAINMENT COUNTY SIGNIFICANT "LINKAGES" FOR 8-HOUR OZONE.

Upwind states	Total linkages	Downwind counties			
AL	3	Fulton GA	Harris TX	Jefferson TX.	
AR	3	Galveston TX	Harris TX	Jefferson TX.	
CT	2	Kent RI	Suffolk NY.		
DE	13	Bucks PA	Camden NJ	Chester PA	Gloucester NJ.
		Hunterdon NJ	Mercer NJ	Middlesex NJ	Monmouth NJ.
		Montgomery PA	Morris NJ	Ocean NJ	Philadelphia PA.
		Suffolk NY.			
FL	1	Fulton GA			
IA	3	Kenosha WI	Macomb MI	Sheboygan WI.	
IL	5	Geauga OH	Kenosha WI	Macomb MI	Ozaukee WI.
		Sheboygan WI.			
IN	5	Geauga OH	Kenosha WI	Macomb MI	Ozaukee WI.
		Sheboygan WI..			
KY	3	Fulton GA	Geauga OH	Macomb MI.	
LA	3	Galveston TX	Harris TX	Jefferson TX.	
MA	2	Kent RI	Middlesex NJ.		
MD/DC	23	Arlington VA	Bergen NJ	Bucks PA	Camden NJ.
		Chester PA	District of Columbia	Erie NY	Fairfax VA.
		Fairfield CT	Gloucester NJ	Hunterton NJ	Mercer NJ.
		Middlesex NJ	Monmouth NJ	Montgomery PA	Morris NJ.

[104] As noted above, we combined Maryland and the District of Columbia as a single entity in our contribution modeling. This is a logical approach because of the small size of the District of Columbia and, hence, its emissions and its close proximity to Maryland. Under our analysis, Maryland and the District of Columbia are linked as significant contributors to the same downwind nonattainment counties. The EPA received no adverse comment on this approach. We also considered these entities separately, and in view of the close proximity of these two areas we believe that Maryland is linked as a significant contributor to nonattainment in the District of Columbia and that the District of Columbia is linked as a significant contributor to nonattainment in Maryland.

TABLE VI–9.—UPWIND STATE-TO-DOWNWIND NONATTAINMENT COUNTY SIGNIFICANT "LINKAGES" FOR 8-HOUR OZONE.—Continued

		New Castle DE	New Haven CT	Ocean NJ	Philadelphia PA.
		Richmond NY	Suffolk NY	Westchester NY	
MI	19	Anne Arundel MD	Bergen NJ	Bucks PA	Camden NJ.
		Cecil MD	Chester PA	Erie NY	Geauga OH.
		Gloucester NJ	Kent MD	Mercer NJ	Middlesex NJ.
		Monmouth NJ	Morris NJ	New Castle DE	Ocean NJ.
		Philadelphia PA	Richmond NY	Suffolk NY	
MO	4	Geauga OH	Kenosha WI	Ozaukee WI	Sheboygan WI.
MS	2	Harris TX	Jefferson TX.		
NC	8	Anne Arundel MD	Fulton GA	Harford MD	Kent MD.
		Newcastle DE	Suffolk NY	Bucks PA	Chester PA.
NJ	10	Erie NY	Fairfield CT	Kent RI	Middlesex CT.
		Montgomery PA	New Haven CT	Philadelphia PA	Richmond NY.
		Suffolk NY	Westchester NY.		
NY	9	Fairfield CT	Kent RI	Mercer NJ	Middlesex CT.
		Middlesex NJ	Monmouth NJ	Morris NJ	New Haven CT.
		Ocean NJ.			
		Anne Arundel MD	Arlington VA	Bergen NJ	Bucks PA.
OH	28	Camden NJ	Cecil MD	Chester PA	District of Columbia.
		Fairfax VA	Fairfield CT	Gloucester NJ	Harford MD.
		Hunterton NJ	Kent MD	Kent RI	Macomb MI.
		Mercer NJ	Middlesex CT	Middlesex NJ	Monmouth NJ.
		Montgomery PA	Morris NJ	New Castle DE	New Haven CT.
		Ocean NJ	Philadelphia PA	Suffolk NY	Westchester NY.
PA	25	Anne Arundel MD	Arlington VA	Bergen NJ	Camden NJ.
		Cecil MD	District of Columbia	Erie NY	Fairfax VA.
		Fairfield CT	Gloucester NJ	Harford MD	Hunterton NJ.
		Kent MD	Kent RI	Mercer NJ	Middlesex CT.
		Middlesex NJ	Monmouth NJ	Morris NJ	New Castle DE.
		New Haven CT	Ocean NJ	Richmond NY	Suffolk NY.
		Westchester NY.			
SC	1	Fulton GA.			
TN	1	Fulton GA.			
VA	26	Anne Arundel MD	Bergen NJ	Bucks PA	Camden NJ.
		Cecil MD	Chester PA	District of Columbia	Erie NY.
		Fairfield CT	Gloucester NJ	Harford MD	Hunterton NJ.
		Kent MD	Kent RI	Mercer NJ	Middlesex CT.
		Middlesex NJ	Monmouth NJ	Morris NJ	New Castle DE.
		New Haven CT	Ocean NJ	Philadelphia PA	Richmond NY.
		Suffolk NY	Westchester NY.		
WI	2	Erie NY	Macomb MI.		
WV	25	Anne Arundel MD	Bergen NJ	Bucks PA	Camden NJ.
		Cecil MD	Chester PA	Fairfax VA	Fairfield CT.
		Fulton GA	Gloucester NJ	Harford MD	Hunterton NJ.
		Kent MD	Mercer NJ	Middlesex NJ	Monmouth NJ.
		Montgomery PA	Morris NJ	New Castle DE	New Haven CT.
		Ocean NJ	Philadelphia PA	Richmond NY	Suffolk NY.
		Westchester NY.			

E. What are the Estimated Air Quality Impacts of the Final Rule?

In this section, we describe the air quality modeling performed to determine the projected impacts on $PM_{2.5}$ and 8-hour ozone of the SO_2 and NO_X emissions reductions in the control region modeled. The modeling used to estimate the air quality impact of these reductions assumes annual SO_2 and NO_X controls for Arkansas, Delaware, and New Jersey in addition to the 23-States plus the District of Columbia. Since Arkansas, Delaware, and New Jersey are not included in the final CAIR region for $PM_{2.5}$, the modeled estimated impacts on $PM_{2.5}$ are overstated for today's final rule. However, EPA plans to include Delaware and New Jersey in the CAIR region for $PM_{2.5}$ through a separate regulatory process. Thus, the estimates are reflective of the total impacts expected for CAIR assuming Delaware and New Jersey will become part of the annual SO_2 and NO_X trading programs.

As discussed in section IV, EPA analyzed the impacts of the regional emissions reductions in both 2010 and 2015. These impacts are quantified by comparing air quality modeling results for the regional control scenario to the modeling results for the corresponding 2010 and 2015 base case scenarios. The 2010 and 2015 emissions reductions from the power generation sector include a two-phase cap and trade program covering the control region modeled (*i.e.*, the 23 States plus the District of Columbia included in today's rule and Arkansas, Delaware, and New Jersey).[105] Phase 1 of the regional strategy (the 2010 reductions) is forecast to reduce total EGU SO_2 emissions [106] in

[105] In addition to the SO_2 and NO_X reductions in these States, we also modeled summer-season only EGU NO_X controls for Connecticut and Massachusetts, which significantly contribute to ozone, but not to $PM_{2.5}$ nonattainment in downwind areas.

[106] For the purposes of this discussion, we have calculated the percent reduction in total EGU

the control region modeled by 40 percent in 2010. Phase 2 (the 2015 reductions) is forecast to provide a 48 percent reduction in EGU SO_2 emissions compared to the base case in 2015. When fully implemented post-2015, we expect this rule to result in more than a 70 percent reduction in EGU SO_2 emissions compared to current emissions levels. The reductions at full implementation occur post-2015 due to the existing title IV bank of SO_2 allowances, which can be used under the CAIR program. The net effect of the strategy on total SO_2 emissions in the control region modeled considering all sources of emissions, is a 28 percent reduction in 2010 and a 32 percent reduction in 2015.

For NO_X, Phase 1 of the strategy is forecast to reduce total EGU emissions by 44 percent in 2009. Total NO_X emissions across the control region (*i.e.*, includes all sources) are 11 percent lower in the 2010 CAIR scenario compared to the emissions in the 2010 base case. In Phase 2, EGU NO_X emissions are projected to decline by 54 percent in 2015 in this region. Total NO_X emissions from all anthropogenic sources are projected to be reduced by 14 percent in 2015. The percent change in emissions by State for SO_2 and NO_X in 2010 and 2015 for the regional control strategy modeled are provided in the NFR EITSD.

1. Estimated Impacts on $PM_{2.5}$ Concentrations and Attainment

We determined the impacts on $PM_{2.5}$ of the CAIR regional strategy by running the CMAQ model for this strategy and comparing the results to the $PM_{2.5}$ concentrations predicted for the 2010 and 2015 base cases. In brief, we ran the CMAQ model for the regional strategy in both 2010 and 2015. The model predictions were used to project future $PM_{2.5}$ concentrations for CAIR in 2010 and 2015 using the SMAT technique, as described in section VI.B.1. We compared the results of the 2010 and 2015 regional strategy modeling to the corresponding results from the 2010 and 2015 base cases to quantify the expected impacts of CAIR.

The impacts of the SO_2 and NO_X emissions reductions expected from CAIR on $PM_{2.5}$ in 2010 and 2015 are provided in Table VI–10 and Table VI–11, respectively. In these tables, counties shown in bold/italics are projected to come into attainment with CAIR.

TABLE VI–10.—PROJECTED $PM_{2.5}$ CONCENTRATIONS ($\mu g/m^3$) FOR THE 2010 BASE CASE AND CAIR AND THE IMPACT OF CAIR REGIONAL CONTROLS IN 2010

State	County	2010 Base case	2010 CAIR	Impact of CAIR
Alabama	DeKalb Co	15.23	13.97	−1.26
Alabama	Jefferson Co	18.57	17.46	−1.11
Alabama	Montgomery Co	15.12	14.10	−1.02
Alabama	Morgan Co	15.29	14.11	−1.18
Alabama	Russell Co	16.17	15.15	−1.02
Alabama	Talladega Co	15.34	14.00	−1.34
Delaware	New Castle Co	16.56	14.84	−1.72
District of Columbia		15.84	13.68	−2.16
Georgia	Bibb Co	16.27	15.17	−1.10
Georgia	Clarke Co	16.39	14.96	−1.43
Georgia	Clayton Co	17.39	16.29	−1.10
Georgia	Cobb Co	16.57	15.35	−1.22
Georgia	DeKalb Co	16.75	15.70	−1.05
Georgia	Floyd Co	16.87	15.87	−1.00
Georgia	Fulton Co	18.02	16.98	−1.04
Georgia	Hall Co	15.60	14.28	−1.32
Georgia	Muscogee Co	15.65	14.57	−1.08
Georgia	Richmond Co	15.68	14.64	−1.04
Georgia	Walker Co	15.43	14.22	−1.21
Georgia	Washington Co	15.31	14.22	−1.09
Georgia	Wilkinson Co	16.27	15.22	−1.05
Illinois	Cook Co	17.52	16.88	−0.64
Illinois	Madison Co	16.66	15.96	−0.70
Illinois	St. Clair Co	16.24	15.54	−0.70
Indiana	Clark Co	16.51	15.15	−1.36
Indiana	Dubois Co	15.73	14.37	−1.36
Indiana	Lake Co	17.26	16.48	−0.78
Indiana	Marion Co	16.83	15.54	−1.29
Indiana	Vanderburgh Co	15.54	14.26	−1.28
Kentucky	Boyd Co	15.23	13.38	−1.85
Kentucky	Bullitt Co	15.10	13.67	−1.43
Kentucky	Fayette Co	15.95	14.17	−1.78
Kentucky	Jefferson Co	16.71	15.44	−1.27
Kentucky	Kenton Co	15.30	13.72	−1.58
Maryland	Anne Arundel Co	15.26	12.98	−2.28
Maryland	Baltimore city	16.96	14.88	−2.08
Michigan	Wayne Co	19.41	18.23	−1.18
Missouri	St. Louis City	15.10	14.40	−0.70
New Jersey	Union Co	15.05	13.60	−1.45
New York	New York Co	16.19	14.95	−1.24
North Carolina	Catawba Co	15.48	14.07	−1.41
North Carolina	Davidson Co	15.76	14.36	−1.40

emissions which includes units greater than and less than 25 MW.

TABLE VI–10.—PROJECTED $PM_{2.5}$ CONCENTRATIONS (μG/M³) FOR THE 2010 BASE CASE AND CAIR AND THE IMPACT OF CAIR REGIONAL CONTROLS IN 2010—Continued

State	County	2010 Base case	2010 CAIR	Impact of CAIR
North Carolina	Mecklenburg Co	15.22	13.92	−1.30
Ohio	Butler Co	16.45	15.03	−1.42
Ohio	Cuyahoga Co	18.84	17.11	−1.73
Ohio	Franklin Co	16.98	15.13	−1.85
Ohio	Hamilton Co	18.23	16.61	−1.62
Ohio	Jefferson Co	17.94	15.64	−2.30
Ohio	Lawrence Co	16.10	14.11	−1.99
Ohio	Mahoning Co	15.39	13.40	−1.99
Ohio	Montgomery Co	15.41	13.83	−1.58
Ohio	Scioto Co	18.13	15.98	−2.15
Ohio	Stark Co	17.14	15.08	−2.06
Ohio	Summit Co	16.47	14.69	−1.78
Ohio	Trumbull Co	15.28	13.50	−1.78
Pennsylvania	Allegheny Co	20.55	18.01	−2.54
Pennsylvania	Beaver Co	15.78	13.61	−2.17
Pennsylvania	Berks Co	15.89	13.56	−2.33
Pennsylvania	Cambria Co	15.14	12.72	−2.42
Pennsylvania	Dauphin Co	15.17	12.88	−2.29
Pennsylvania	Delaware Co	15.61	13.94	−1.67
Pennsylvania	Lancaster Co	16.55	14.09	−2.46
Pennsylvania	Philadelphia Co	16.65	14.98	−1.67
Pennsylvania	Washington Co	15.23	12.99	−2.24
Pennsylvania	Westmoreland Co	15.16	12.60	−2.56
Pennsylvania	York Co	16.49	14.20	−2.29
Tennessee	Davidson Co	15.36	14.26	−1.10
Tennessee	Hamilton Co	16.89	15.57	−1.32
Tennessee	Knox Co	17.44	16.16	−1.28
Tennessee	Sullivan Co	15.32	14.01	−1.31
West Virginia	Berkeley Co	15.69	13.43	−2.26
West Virginia	Brooke Co	16.63	14.42	−2.21
West Virginia	Cabell Co	17.03	15.08	−1.95
West Virginia	Hancock Co	17.06	14.89	−2.17
West Virginia	Kanawha Co	17.56	15.27	−2.29
West Virginia	Marion Co	15.32	12.90	−2.42
West Virginia	Marshall Co	15.81	13.46	−2.35
West Virginia	Ohio Co	15.14	12.81	−2.33
West Virginia	Wood Co	16.66	14.14	−2.52

TABLE VI–11.—PROJECTED $PM_{2.5}$ CONCENTRATIONS (μG/M³) FOR THE 2015 BASE CASE AND CAIR AND THE IMPACT OF CAIR REGIONAL CONTROLS IN 2015

State	County	2015 Base case	2015 CAIR	Impact of CAIR
Alabama	DeKalb Co	15.24	13.46	−1.78
Alabama	Jefferson Co	18.85	17.36	−1.49
Alabama	Montgomery Co	15.24	13.87	−1.37
Alabama	Morgan Co	15.26	13.85	−1.41
Alabama	Russell Co	16.10	14.66	−1.44
Alabama	Talladega Co	15.22	13.35	−1.87
Delaware	New Castle Co	16.47	14.41	−2.06
District of Columbia		15.57	13.11	−2.46
Georgia	Bibb Co	16.41	14.83	−1.58
Georgia	Chatham Co	15.06	13.86	−1.20
Georgia	Clarke Co	16.15	14.10	−2.05
Georgia	Clayton Co	17.46	15.85	−1.61
Georgia	Cobb Co	16.51	14.67	−1.84
Georgia	DeKalb Co	16.82	15.29	−1.53
Georgia	Floyd Co	17.33	15.79	−1.54
Georgia	Fulton Co	18.00	16.47	−1.53
Georgia	Hall Co	15.36	13.48	−1.88
Georgia	Muscogee Co	15.58	14.06	−1.52
Georgia	Richmond Co	15.76	14.23	−1.53
Georgia	Walker Co	15.37	13.65	−1.72
Georgia	Washington Co	15.34	13.67	−1.67
Georgia	Wilkinson Co	16.54	15.01	−1.53
Illinois	Cook Co	17.71	16.95	−0.76
Illinois	Madison Co	16.90	16.07	−0.83
Illinois	St. Clair Co	16.49	15.64	−0.85

TABLE VI–11.—PROJECTED $PM_{2.5}$ CONCENTRATIONS ($\mu g/m^3$) FOR THE 2015 BASE CASE AND CAIR AND THE IMPACT OF CAIR REGIONAL CONTROLS IN 2015—Continued

State	County	2015 Base case	2015 CAIR	Impact of CAIR
Illinois	Will Co	15.12	14.27	−0.85
Indiana	Clark Co	16.37	14.79	−1.58
Indiana	Dubois Co	15.66	14.16	−1.50
Indiana	Lake Co	17.27	16.36	−0.91
Indiana	Marion Co	16.77	15.38	−1.39
Indiana	Vanderburgh Co	15.56	14.17	−1.39
Kentucky	Boyd Co	15.06	12.95	−2.11
Kentucky	Fayette Co	15.62	13.54	−2.08
Kentucky	Jefferson Co	16.61	15.13	−1.48
Kentucky	Kenton Co	15.09	13.26	−1.83
Maryland	Baltimore city	17.04	14.50	−2.54
Maryland	Baltimore Co	15.08	12.75	−2.33
Michigan	Wayne Co	19.28	17.95	−1.33
Mississippi	Jones Co	15.18	14.06	−1.12
Missouri	St. Louis city	15.34	14.50	−0.84
New York	New York Co	15.76	14.33	−1.43
North Carolina	Catawba Co	15.19	13.45	−1.74
North Carolina	Davidson Co	15.34	13.61	−1.73
Ohio	Butler Co	16.32	14.67	−1.65
Ohio	Cuyahoga Co	18.60	16.67	−1.93
Ohio	Franklin Co	16.64	14.57	−2.07
Ohio	Hamilton Co	18.03	16.10	−1.93
Ohio	Jefferson Co	17.83	15.26	−2.57
Ohio	Lawrence Co	15.92	13.71	−2.21
Ohio	Mahoning Co	15.13	12.94	−2.19
Ohio	Montgomery Co	15.16	13.33	−1.83
Ohio	Scioto Co	17.92	15.55	−2.37
Ohio	Stark Co	16.86	14.58	−2.28
Ohio	Summit Co	16.14	14.18	−1.96
Ohio	Trumbull Co	15.05	13.08	−1.97
Pennsylvania	Allegheny Co	20.33	17.47	−2.86
Pennsylvania	Beaver Co	15.54	13.09	−2.45
Pennsylvania	Berks Co	15.66	12.99	−2.67
Pennsylvania	Delaware Co	15.52	13.52	−2.00
Pennsylvania	Lancaster Co	16.28	13.33	−2.95
Pennsylvania	Philadelphia Co	16.53	14.53	−2.00
Pennsylvania	York Co	16.22	13.46	−2.76
Tennessee	Davidson Co	15.36	14.02	−1.34
Tennessee	Hamilton Co	16.82	14.94	−1.88
Tennessee	Knox Co	17.34	15.61	−1.73
Tennessee	Shelby Co	15.17	14.19	−0.98
Tennessee	Sullivan Co	15.37	13.77	−1.60
West Virginia	Berkeley Co	15.32	12.73	−2.59
West Virginia	Brooke Co	16.51	14.05	−2.46
West Virginia	Cabell Co	16.86	14.64	−2.22
West Virginia	Hancock Co	16.97	14.54	−2.43
West Virginia	Kanawha Co	17.17	14.66	−2.51
West Virginia	Marshall Co	15.52	12.87	−2.65
West Virginia	Wood Co	16.69	13.88	−2.81

As described in section VI.B.1, we project that 79 counties in the East will be nonattainment for $PM_{2.5}$ in the 2010 base case. We estimate that, on average, the regional strategy will reduce $PM_{2.5}$ in these 79 counties by 1.6 $\mu g/m^3$. In over 90 percent of the nonattainment counties (*i.e.*, 74 out of 79 counties), we project that $PM_{2.5}$ will be reduced by at least 1.0 $\mu g/m^3$. In over 25 percent of the 79 nonattainment counties (*i.e.*, 23 of the 79 counties), we project $PM_{2.5}$ concentrations will decline by of more than 2.0 $\mu g/m^3$. Of the 79 counties that are nonattainment in the 2010 Base, we project that 51 counties will come into attainment as a result of the SO_2 and NO_X emissions reductions expected from the regional controls. Even those 28 counties that remain nonattainment in 2010 after implementation of the regional strategy will be closer to attainment as a result of these emissions reductions. Specifically, the average reduction of $PM_{2.5}$ in the 28 residual nonattainment counties is projected to be 1.3 $\mu g/m^3$. After implementation of the regional controls, we project that 18 of the 28 residual nonattainment counties in 2010 will be within 1.0 $\mu g/m^3$ of the NAAQS and 12 counties will be within 0.5 $\mu g/m^3$ of attainment.

In 2015 we are projecting that $PM_{2.5}$ in the 74 base case nonattainment counties will be reduced by 1.8 $\mu g/m^3$, on average, as a result of the SO_2 and NO_X reductions in the regional strategy. In over 90 percent of the nonattainment counties (*i.e.*, 67 of the 74 counties) concentrations of $PM_{2.5}$ are predicted to be reduced by at least 1.0 $\mu g/m^3$. In over 35 percent of the counties (*i.e.*, 27 of the 74 counties), we project the regional strategy to reduce $PM_{2.5}$ by more than 2.0 $\mu g/m^3$. As a result of the reductions in $PM_{2.5}$, 56 nonattainment counties are projected to come into attainment in 2015. The remaining 18 nonattainment counties are projected to be closer to attainment with the regional strategy. Our modeling results indicate that $PM_{2.5}$ will be reduced in the range of 0.7 μg/m³ to 2.9 μg/m³ in these 18 counties. The average reduction across these 18 residual nonattainment counties is 1.5 μg/m³.

Thus, the SO_2 and NO_X emissions reductions which will result from the regional strategy will greatly reduce the extent of $PM_{2.5}$ nonattainment by 2010 and beyond. These emissions reductions are expected to substantially reduce the number of $PM_{2.5}$ nonattainment counties in the East and make attainment easier for those counties that remain nonattainment by substantially lowering $PM_{2.5}$ concentrations in these residual nonattainment counties.

2. Estimated Impacts on 8-Hour Ozone Concentrations and Attainment

We determined the impacts on 8-hour ozone of the regional strategy by running the CAM_X model for this strategy and comparing the results to the ozone concentrations predicted for the 2010 and 2015 base cases. In brief, we ran the CAM_X model for the regional strategy in both 2010 and 2015. The model predictions were used to project future 8-hour ozone concentrations for the regional strategy in 2010 and 2015 using the Relative Reduction Factor technique, as described in section VI.B.1. We compared the results of the 2010 and 2015 regional strategy modeling to the corresponding results from the 2010 and 2015 base cases to quantify the expected impacts of the regional controls.

The results of the regional strategy ozone modeling are expressed in terms of the expected reductions in projected 8-hour concentrations and the implications for future nonattainment. The impacts of the regional NO_X emissions reductions on 8-hour ozone in 2010 and 2015 are provided in Table VI–12 and Table VI–13, respectively. In these tables, counties shown in bold/italics are projected to come into attainment with the regional controls.

TABLE VI–12.—PROJECTED 8-HOUR CONCENTRATIONS (PPB) FOR THE 2010 BASE CASE AND CAIR AND THE IMPACT OF CAIR REGIONAL CONTROLS IN 2010

State	County	2010 Base case	2010 CAIR	Impact of CAIR
Connecticut	Fairfield Co	92.6	92.2	−0.4
Connecticut	Middlesex Co	90.9	90.6	−0.3
Connecticut	New Haven Co	91.6	91.3	−0.3
District of Columbia	District of Columbia	85.2	85.0	−0.2
Delaware	New Castle Co	85.0	84.7	−0.3
Georgia	Fulton Co	86.5	85.1	−1.4
Maryland	Anne Arundel Co	88.8	88.6	−0.2
Maryland	Cecil Co	89.7	89.5	−0.2
Maryland	Harford Co	93.0	92.8	−0.2
Maryland	Kent Co	86.2	85.8	−0.4
Michigan	Macomb Co	85.5	85.4	−0.1
New Jersey	Bergen Co	86.9	86.0	−0.9
New Jersey	Camden Co	91.9	91.6	−0.3
New Jersey	Gloucester Co	91.8	91.3	−0.5
New Jersey	Hunterdon Co	89.0	88.6	−0.4
New Jersey	Mercer Co	95.6	95.2	−0.4
New Jersey	Middlesex Co	92.4	92.1	−0.3
New Jersey	Monmouth Co	86.6	86.4	−0.2
New Jersey	Morris Co	86.5	85.5	−1.0
New Jersey	Ocean Co	100.5	100.3	−0.2
New York	Erie Co	87.3	86.9	−0.4
New York	Richmond Co	87.3	87.1	−0.2
New York	Suffolk Co	91.1	90.8	−0.3
New York	Westchester Co	85.3	84.7	−0.6
Ohio	Geauga Co	87.1	86.6	−0.5
Pennsylvania	Bucks Co	94.7	94.3	−0.4
Pennsylvania	Chester Co	85.7	85.4	−0.3
Pennsylvania	Montgomery Co	88.0	87.6	−0.4
Pennsylvania	Philadelphia Co	90.3	89.9	−0.4
Rhode Island	Kent Co	86.4	86.2	−0.2
Texas	Denton Co	87.4	86.8	−0.6
Texas	Galveston Co	85.1	84.6	−0.5
Texas	Harris Co	97.9	97.4	−0.5
Texas	Jefferson Co	85.6	85.0	−0.6
Texas	Tarrant Co	87.8	87.2	−0.6
Virginia	Arlington Co	86.2	86.0	−0.2
Virginia	Fairfax Co	85.7	85.4	−0.3
Wisconsin	Kenosha Co	91.3	91.0	−0.3
Wisconsin	Ozaukee Co	86.2	85.8	−0.4
Wisconsin	Sheboygan Co	88.3	87.7	−0.6

TABLE VI–13.—PROJECTED 8-HOUR CONCENTRATIONS (PPB) FOR THE 2015 BASE CASE AND CAIR AND THE IMPACT OF CAIR REGIONAL CONTROLS IN 2015

State	County	2015 Base case	2015 CAIR	Impact of CAIR
Connecticut	Fairfield Co	91.4	90.6	−0.8

TABLE VI–13.—PROJECTED 8-HOUR CONCENTRATIONS (PPB) FOR THE 2015 BASE CASE AND CAIR AND THE IMPACT OF CAIR REGIONAL CONTROLS IN 2015—Continued

State	County	2015 Base case	2015 CAIR	Impact of CAIR
Connecticut	Middlesex Co	89.1	88.4	−0.7
Connecticut	New Haven Co	89.8	89.1	−0.7
Maryland	Anne Arundel Co	86.0	84.9	−1.1
Maryland	Cecil Co	86.9	85.4	−1.5
Maryland	Harford Co	90.6	89.6	−1.0
Michigan	Macomb Co	85.1	84.2	−0.9
New Jersey	Bergen Co	85.7	84.5	−1.2
New Jersey	Camden Co	89.5	88.3	−1.2
New Jersey	Gloucester Co	89.6	88.2	−1.4
New Jersey	Hunterdon Co	86.5	85.4	−1.1
New Jersey	Mercer Co	93.5	92.4	−1.1
New Jersey	Middlesex Co	89.8	88.8	−1.0
New Jersey	Ocean Co	98.0	96.9	−1.1
New York	Erie Co	85.2	84.2	−1.0
New York	Suffolk Co	89.9	89.0	−0.9
Pennsylvania	Bucks Co	93.0	91.8	−1.2
Pennsylvania	Montgomery Co	86.5	84.9	−1.6
Pennsylvania	Philadelphia Co	88.9	87.5	−1.4
Texas	Harris Co	97.3	96.4	−0.9
Texas	Jefferson Co	85.0	84.1	−0.9
Wisconsin	Kenosha Co	89.4	88.8	−0.6

As described in section VI.B.1, we project that 40 counties in the East would be nonattainment for 8-hour ozone under the assumptions in the 2010 base case. Our modeling of the regional controls in 2010 indicates that 3 of these counties will come into attainment of the 8-hour ozone NAAQS and that ozone in 16 of the 40 nonattainment counties will be reduced by 1 ppb or more. In addition, our modeling predicts that 8-hour ozone exceedances (*i.e.*, 8-hour ozone of 85 ppb or higher) within nonattainment areas are expected to decline by 5 percent in 2010 with CAIR. Of the 37 counties that are projected to remain nonattainment in 2010 after the regional strategy, nearly half (*i.e.*, 16 of the 37 counties) are within 2 ppb of attainment.

In 2015, we project that 6 of the 22 counties which are nonattainment for 8-hour ozone in the base case will come into attainment with the regional strategy. Ozone concentrations in over 70 percent (*i.e.*, 16 of 22 counties) of the 2015 base case nonattainment counties are projected to be reduced by 1 ppb or more as a result of the regional strategy. Exceedances of the 8-hour ozone NAAQS are predicted to decline in nonattainment areas by 14 percent with regional controls in place in 2015. Thus, the NO_X emissions reductions which will result from the regional strategy will help to bring 8-hour ozone nonattainment areas in the East closer to attainment by 2010 and beyond.

F. What are the Estimated Visibility Impacts of the Final Rule?

1. Methods for Calculating Projected Visibility in Class I Areas

The NPR contained example future year visibility projections for the 20 percent worst days and 20 percent best days at Class I areas that had complete IMPROVE monitoring data in 1996. Changes in future visibility were predicted by using the REMSAD model to generate relative visibility changes, then applying those changes to measured current visibility data. Details of the visibility modeling and calculations can be found in the NPR AQMTSD. An example visibility calculation was given in Appendix M of the NPR AQMTSD along with the predicted improvement in visibility (in deciviews) on the 20 percent best and worst days at 44 Class I areas. The data contained in Appendix M was for informational purposes only and was not used in the significant contribution determination or control strategy development decisions.

The SNPR contained visibility calculations in support of the ''better-than-BART'' analysis. The better-than-BART analysis employed a two-pronged test to determine if the modeled visibility improvements from the CAIR cap and trade program for EGU's were ''better'' than the visibility improvements from a nationwide BART program. The analysis used the visibility calculation methodology detailed in the NPR TSD. Detailed results of the SNPR better-than-BART analysis are contained in the SNPR AQMTSD. The better-than-BART analysis for the final rule is addressed in section IX.C.2 of the preamble. Additional information on the visibility calculation methodology is contained in the NFR AQMTSD.

2. Visibility Improvements in Class I Areas

For the NFR we have modeled several new CAIR [107] and CAIR + BART cases to re-examine the better-than-BART two-pronged test. We have modeled an updated nationwide BART scenario as well as a CAIR in the East/BART in the West scenario. The results were analyzed at 116 Class I areas that have complete IMPROVE data for 2001 or are represented by IMPROVE monitors with complete data. Twenty-nine of the Class I areas are in the East and 87 are in the West. The results of the visibility analysis are summarized in section IX.C.2. Detailed results for all 116 Class I areas are presented in the NFR AQMTSD.

VII. SIP Criteria and Emissions Reporting Requirements

This section describes: (1) The criteria we will use in determining approvability of SIPs submitted to meet the requirements of today's rulemaking; (2) the dates for submittal of the SIPs that are required under the CAIR; (3) the consequences of either failing to submit such a SIP or submitting a SIP which is

[107] The CAIR scenario modeled for the visibility analysis included controls in Arkansas, Delaware, and New Jersey.

disapproved; and (4) the emissions inventory reporting requirements for States.

A. What Criteria Will EPA Use To Evaluate the Approvability of a Transport SIP?

1. Introduction

The approvability criteria for CAIR SIP submissions are finalized today in 40 CFR 51.123 (NO_X emissions reductions) and in 40 CFR 51.124 (SO_2 emissions reductions). Most of the criteria are substantially similar to those that currently apply to SIP submissions under CAA section 110 or part D (nonattainment). For example, each submission must describe the control measures that the State intends to employ, identify the enforcement methods for monitoring compliance and managing violations, and demonstrate that the State has legal authority to carry out its plan.

This part of the preamble explains additional approvability criteria specific to the CAIR that were proposed and discussed in the CAIR NPR or in the CAIR SNPR, and are being promulgated today. As explained in both the CAIR NPR and the CAIR SNPR, EPA proposed that each affected State must submit SIP revisions containing control measures that assure that a specified amount of NO_X and SO_2 emissions reductions are achieved by specified dates.

Although EPA determined the amount of emissions reductions required by identifying specific, highly cost-effective control levels for EGUs, EPA explained in the CAIR NPR and the CAIR SNPR that States have flexibility in choosing which sources to control to achieve the required emissions reductions. As long as a State's emissions reductions requirements are met, a State may impose controls on EGUs only, on non-EGUs only, or on a combination of EGUs and non-EGUs. The SIP approvability criteria are intended to provide as much certainty as possible that, whichever sources a State chooses to control, the controls will result in the required amount of emissions reductions.

In the CAIR NPR, EPA proposed a ''hybrid'' approach for the mechanisms used to ensure emissions reductions are achieved. This approach incorporates elements of an emissions ''budget'' approach (requiring an emissions cap on affected sources) and an ''emissions reduction'' approach (not requiring an emissions cap). In this hybrid approach, if States impose control measures on EGUs, they would be required to impose an emissions cap on all EGUs, which would effectively be an emissions budget. And, as stated in the CAIR NPR, if States impose control measures on non-EGUs, they would be encouraged but not required to impose an emissions cap on non-EGUs. In the CAIR NPR, we requested comment on the issue of requiring States to impose caps on any source categories that the State chooses to regulate.

In the CAIR SNPR, we proposed to modify the hybrid approach and require States that choose to control large industrial boilers or turbines (greater than 250 MMBTU/hr) to impose an emissions cap on all such sources within their State. This is similar to EPA's approach in the NO_X SIP Call which required States to include an emissions cap on such sources as well as on EGUs if the SIP submittals included controls on such sources. (See 40 CFR 51.121(f)(2)(ii).)

A few commenters supported the use of emissions caps on any source category subject to CAIR controls, including non-EGUs, because it would be the most effective way to demonstrate compliance with the budget. A few other commenters opposed the use of an emissions cap on non-EGUs, saying either that States should have the flexibility to determine whether to impose a cap, or that such a requirement would result in increased costs for non-EGUs including cogeneration units that are non-EGUs. No commenter opposing such a requirement provided any information indicating that such a requirement would be ineffective or impracticable. Today EPA is adopting the modified approach, as described in the CAIR SNPR, that States choosing to control EGUs or large industrial boilers or turbines must do so by imposing an emissions cap on such sources, similar to what was required in the NO_X SIP Call.

Extensive comments were received regarding the need for an ozone season NO_X cap in States identified to be contributing significantly to the region's ozone nonattainment problems. In proposal, EPA stated that the annual NO_X cap under CAIR reduced NO_X emissions sufficiently enough to not warrant a regional ozone season NO_X cap. Commenters remained very concerned that the annual NO_X cap would not aid ozone attainment. While EPA feels that the annual NO_X limit will most likely be protective in the ozone season, a seasonal cap will provide certainty, which EPA agrees is very important in the effort to help areas achieve ozone attainment. Today, EPA is finalizing an ozone season NO_X cap for States shown to contribute significantly for ozone. As is further explained in section VIII, EPA is also finalizing an ozone season trading program that States may use to achieve the required emissions reductions. This program will subsume the existing NO_X SIP Call trading program. Therefore, any State that wishes to continue including its sources in an interstate trading program run by EPA to achieve the emissions reductions required by EPA must modify its SIP to conform with this new trading program.

The EPA will automatically find that a State is continuing to meet its NO_X SIP Call obligation if it achieves all of its required CAIR emissions reductions by capping EGUs, it modifies its existing NO_X SIP Call to require its non-EGUs currently participating in the NO_X SIP Call budget trading program to conform to the requirements of the CAIR ozone season NO_X trading program with a trading budget that is the same or tighter than the budget in the currently approved SIP, and it does not modify any of its other existing NO_X SIP Call rules. If a State chooses to achieve the ozone season NO_X emissions reduction requirements of CAIR in another way, it will also be required to demonstrate that it continues to meet the requirements of the NO_X SIP Call.

Specific criteria for approval of CAIR SIP submissions as promulgated by today's action are described below. The criteria are dependent on the types of sources a State chooses to control.

2. Requirements for States Choosing To Control EGUs

a. Emissions Caps and Monitoring

As explained in the CAIR NPR (69 FR 4626), and in the CAIR SNPR (69 FR 32691), EPA proposed requiring States to apply the ''budget'' approach if they choose to control EGUs; that is, each State must cap total EGU emissions at the level that assures the appropriate amount of reductions for that State. The requirement to cap all EGUs is important because it prevents shifting of utilization (and resulting emissions) to uncapped EGUs. The EGUs are part of a highly interconnected electricity grid that makes utilization shifting likely and even common. The units are large and offer the same market product (*i.e.*, electricity), and therefore the units that are least expensive to operate are likely to be operated as much as possible. If capped and uncapped units are interconnected, the uncapped units' costs would tend to decrease relative to the capped units, which must either reduce emissions or use or buy allowances, and the uncapped units' utilization would likely increase. The cap ensures that emissions reductions from these interconnected sources are actually achieved rather than emissions simply shifting among sources. The caps constitute the State EGU Budgets for SO_2 and NO_X. Additionally, EPA proposed that, if States choose to control EGUs, they must require EGUs to follow part 75 monitoring, recordkeeping, and reporting requirements. Part 75 monitoring and reporting requirements have been used effectively for determining NO_X and SO_2 emissions from EGUs under the title IV Acid Rain program and the NO_X SIP Call program and in combination with emissions caps are an integral part of those programs. (Additional explanation for the need for Part 75 monitoring is given in the NPR and SNPR and is incorporated here.) Therefore, today, EPA adopts the requirements for emission caps and Part 75 monitoring for EGUs in these States.

b. Using the Model Trading Rules

As proposed, if a State chooses to allow its EGUs to participate in EPA-administered interstate NO_X and SO_2 emissions trading programs, the State must adopt EPA's model trading rules, as described elsewhere in today's preamble and in §§ 96.101–96.176 (for NO_X) and §§ 96.201–96.276 (for SO_2), set forth below. Additionally, EPA proposed that for the States for which EPA made a finding of significant contribution for both ozone and $PM_{2.5}$, participation in both the NO_X and SO_2 trading programs would be required in order to be included in the EPA-administered program. States for which the finding was for ozone only could choose to participate in only the EPA-administered NO_X trading program through adoption of the NO_X model trading rule. The EPA stated that States adopting EPA's model trading rules, modified only as specifically allowed by EPA, will meet the requirement for applying an emissions cap and requirement to use part 75 monitoring, recordkeeping, and reporting for EGUs.

Some commenters opposed EPA's proposal to require participation in both the NO_X and SO_2 trading programs because some States may want to participate in the EPA-administered trading programs for only NO_X or only SO_2. A few commenters claimed that the requirement to participate in both programs would limit State flexibility or is an ''all or nothing'' approach; other commenters objected that there was no environmental basis for such a requirement; and one commenter suggested that States not affected by CAIR but that volunteer to control emissions should be permitted to join the program for one or both pollutants. Additionally, commenters cited a need for an ozone season NO_X program.

The EPA has taken the comments into account and in today's action agrees to allow a State identified to contribute significantly for $PM_{2.5}$ (and therefore required to make annual SO_2 and NO_X reductions) to participate in the EPA-administered CAIR trading program for either SO_2 or NO_X, not necessarily both, so long as the State adopts the model rule for the applicable trading program.

In response to extensive comments relating to EPA's proposal to forego a seasonal NO_X cap because EPA demonstrated that the annual NO_X cap was sufficiently stringent, EPA is finalizing an ozone season NO_X trading program for States identified as contributing significantly for ozone. These States will be subject to an ozone season NO_X cap and an annual NO_X cap if the State is also identified as contributing significantly for $PM_{2.5}$. Therefore, today's action includes an additional model rule for an ozone season NO_X trading program (40 CFR 96, subparts AAAA through IIII). The States that may use the ozone season NO_X trading program but not the annual NO_X trading program are those States in the CAIR region identified as contributing significantly for ozone only (Arkansas, Connecticut, Delaware, Massachusetts, and New Jersey).

As discussed in the proposal, EPA is finalizing the option for New Hampshire and Rhode Island to participate in the regional trading program through use of the CAIR ozone season NO_X model rule because sources in these States have made investments in NO_X controls in the past based on the existence of a regional ozone season NO_X trading program. Additionally, the States' combined projected 2010 and 2015 NO_X emissions are less than one-half of one percent of the total CAIR regional NO_X cap and therefore would not create a significant increase in the CAIR cap. All comments received were supportive of this approach and EPA is finalizing it today.

None of these States (Arkansas, Connecticut, Delaware, Massachusetts, New Hampshire, New Jersey, or Rhode Island) has the option to participate in the EPA-administered CAIR SO_2 trading program nor the annual CAIR NO_X trading program because there are no $PM_{2.5}$-related emissions reductions required under today's action in those States. (Of course, sources in these States will still be subject to the Acid Rain SO_2 cap and trade program.) Likewise, Texas, Minnesota and Georgia may not participate in the ozone season NO_X program, because they have not been shown to contribute significantly to the regional ozone problem. They are, however, required to make annual NO_X and SO_2 reductions and may choose to participate in the annual NO_X and annual SO_2 trading program to meet their CAIR obligations.

Except for the special cases of Rhode Island and New Hampshire, other States outside of the CAIR region may not participate in the CAIR trading programs for either pollutant, because they were not shown to contribute significantly to $PM_{2.5}$ or ozone nonattainment in the CAIR region. Allowing States outside of the CAIR region to participate would generally create an opportunity—through net sales of allowances from the non-CAIR States to CAIR States—for emission increases in States that have been shown to contribute significantly to nonattainment in the CAIR region.[108]

A State may not participate in the EPA-administered trading programs if they choose to get a portion of CAIR reductions from non-EGUs. (This is also discussed in Section VIII.) The EPA maintains that requiring certain consistencies among States in the regionwide trading programs that EPA has offered to run does not unfairly limit States' flexibility to choose an approach for achieving CAIR mandated reductions that is best suited for a particular State's unique circumstances. States are free to achieve the reductions through whatever alternative mechanisms the States wish to design; for example, a group of States could cooperatively implement their own multi-State trading programs that EPA would not administer.

c. Using a Mechanism Other Than the Model Trading Rules

If States choose to control EGUs through a mechanism other than the EPA-administered NO_X and SO_2 emissions trading programs, then the States (i) must still impose an emissions cap on total EGU emissions and require part 75 monitoring, recordkeeping, and reporting requirements on all EGUs, and (ii) must use the same definition of EGU as EPA uses in its model trading rules, i.e., the sources described as ''CAIR units'' in § 96.102, § 96.202, and § 96.302. A few commenters expressed concern that these requirements limit States' discretion in designing control measures to meet the CAIR requirements, but failed to offer any

[108] Title IV allowances can however be traded freely across the boundary of the CAIR region without any significant, negative environmental consequence. The potential negative consequences have been addressed through other requirements discussed below, like the retirement of excess title IV allowances.

reason why the requirements would be impracticable or ineffective. The EPA believes that the requirements are necessary for a number of reasons. The requirements to cap all EGUs and to use the same definition of EGU are important because they prevent shifting of utilization (and resulting emissions) from capped to uncapped sources. In this case, not requiring a cap on total EGU emissions in these States is likely to result in increased utilization and consequently increased emissions in these States. The requirement to use part 75 monitoring ensures the accuracy of monitored data and consistency of reporting among sources (and thus the certainty that emissions reductions actually occurred) across all States. Furthermore, most EGUs are currently monitoring and reporting using part 75 so it does not impose an additional requirement. Therefore, EPA is finalizing the proposed approach.

If a State chooses to design its own intrastate or interstate NO_X or SO_2 emissions trading programs, the State must, in addition to meeting the requirements of the rules finalized in today's action, consider EPA's guidance, ''Improving Air Quality with Economic Incentive Programs,'' January, 2001 (EPA–452/R–01–001) (available on EPA's Web site at: *http://www.epa.gov/ttn/ecas/incentiv.html*). The State's programs are subject to EPA approval. The EPA will not administer a State-designed trading program. Additionally, it should be noted that allowances from any alternate trading program may not be used in the EPA-administered trading programs.

d. Retirement of Excess Title IV Allowances

The CAIR NPR proposed requirements on SIPs relating to the effects of title IV SO_2 allowance allocations for 2010 and beyond that are in excess of the State's CAIR EGU SO_2 emissions budget. The requirements were intended to ensure that the excess is not used in a manner that would lead to a significant increase in supply of title IV allowances, the collapse of the price of title IV allowances, the disruption of operation of the title IV allowance market and the title IV SO_2 cap and trade system, and the potential for increased emissions in all States prior to 2010 and in non-CAIR States in 2010 and later. These negative impacts on the title IV allowance market and on air quality, which are discussed in detail in section IX.B. below, would undermine the efficacy of the title IV program and could erode confidence in cap and trade programs in general. To avoid these impacts, EPA proposed to require retirement of the excess title IV allowances through a retirement ratio mechanism.

The EPA proposed, as a mechanism for removing these additional allowances and meeting the 50 percent reduction required under phase I (2010–2014), that each affected EGU had to hold, and EPA would retire, two vintage 2010–2014 allowances for every ton of SO_2 that the unit emits. Further, EPA proposed that, for phase II (which begins in 2015) when a 65 percent reduction is required, each affected EGU had to hold, and EPA would retire, three vintage 2015 and beyond allowances for every ton of SO_2 that the unit emits. This 3-to-1 ratio would result in slightly more reductions than EPA has determined were necessary to eliminate the significant contribution by an upwind State.

In the CAIR SNPR, EPA proposed two alternatives for addressing the issue of the additional allowances. Under the first alternative, affected EGUs had to hold, and EPA would retire, vintage 2015 and beyond allowances at a rate of 2.86-to-1 rather than 3-to-1, which would result in exactly the amount of reductions EPA has determined are necessary to eliminate a State's significant contribution.

Alternatively, also in the CAIR SNPR, EPA proposed requiring the retirement of 2015 and beyond vintage allowances at a 3-to-1 ratio and permitting States to convert the additional reductions into allowances in their rules. The EPA also suggested that some States may want to use these reserved allowances to create an incentive for additional local emissions reductions that will be needed to bring all areas into attainment with the $PM_{2.5}$ NAAQS.

As part of today's final CAIR rulemaking, EPA is finalizing a ratio of 2.86-to-one. The ratio ultimately represents a reduction of 65 percent from the final title IV cap level, which has been found to be highly cost-effective. For a detailed discussion regarding EPA's determination of highly cost-effective, please refer to Section IV of the final CAIR preamble. As discussed earlier, EPA must employ a uniform ratio across sources to ensure consistency and the same cost-effectiveness level across sources. Therefore, EPA will use a Phase II ratio of 2.86-to-1 for all States affected by CAIR who choose to participate in the trading program.

Today, EPA is finalizing the general requirement that all SIPs must include a mechanism to ensure that excess SO_2 allowances are retired. Furthermore, for States that participate in the EPA-administered cap and trade program, EPA is finalizing a specific mechanism that States must use.

i. States Participating in the EPA-Administered SO_2 Trading Program

If a State chooses to participate in the EPA-administered trading program, the State's excess title IV allowance retirement mechanism must follow the provisions of the SO_2 model trading rule that requires that vintage 2010 through 2014 title IV allowances be retired at a ratio of two allowances for every ton of emissions and that vintage 2015 and beyond title IV allowances be retired at a ratio of 2.86 allowances for every ton of emissions. Pre-2010 vintage allowances would be retired at a ratio of one allowance for every ton of emissions. (See discussion of the model SO_2 cap and trade rule in section VIII of today's preamble.) States using the model SO_2 cap and trade rule satisfy the requirement for retirement of excess title IV allowances.

ii. States Not Participating in the EPA-Administered SO_2 Trading Program

In the CAIR NPR, EPA stated that if a State does not choose to participate in the EPA-administered trading programs but controls only EGUs, the State may choose the specific method to retire allowances in excess of its budget. The EPA considered alternative ways for retiring these excess allowances and, as stated in the CAIR SNPR, believed that the use by different States of different means to address this concern could undermine the regionwide emissions reduction goals of the CAIR rulemaking. The EPA further described its concerns in section II of the preamble to the CAIR SNPR. (*See* 69 FR 32686–32688.) Because of these concerns, in the CAIR SNPR, EPA withdrew the CAIR NPR proposal on this point and re-proposed that all States use a 2-for-1 retirement ratio for vintage 2010 through 2014 allowances and a 2.86-for-1 or a 3-for-1 retirement ratio for vintage 2015 and beyond allowances to address concerns about title IV allowances that exceed State budgets. The EGUs would have a total emissions cap enforced by the State.

The SNPR described that for sources affected by both title IV and CAIR, allowance deductions and associated compliance determinations would be sequential. That is, title IV compliance would be determined and then CAIR compliance would be determined. So, in 2010–2014, after surrendering one vintage 2010 through 2014 allowance for each ton of emissions for title IV compliance, the source would then surrender one additional allowance (for a total of two allowances for each ton which meets the CAIR requirement). Similarly, in 2015 and beyond, after surrendering one vintage 2015 and beyond allowance for each ton of emissions for title IV compliance, the source would surrender 1.86 or 2 additional allowances and therefore meet the CAIR requirement. Commenters argued that in States where EGUs are not trading under CAIR that the excess title IV allowances could be removed in a variety of ways and that EPA did not need to require each State do this the same way, only that each State ensure that they are removed.

Today, EPA adopts the following requirement: If a State does not choose to participate in the EPA-administered trading programs but controls only EGUs, the State must include in its SIP a mechanism for retiring the excess title IV allowances (i.e., the difference between total allowance allocations in the State and the State EGU SO_2 budget). To meet this requirement, the State may use the above-described retirement mechanism or may develop a different mechanism that will achieve the required retirement of excess allowances.

3. Requirements for States Choosing to Control Sources Other Than EGUs

a. Overview of Requirements

As noted in both the CAIR NPR and the CAIR SNPR, if a State chooses to require emissions reductions from non-EGUs, the State must adopt and submit SIP revisions and supporting documentation designed to quantify the amount of reductions from the non-EGU sources and to assure that the controls will achieve that amount. Although EPA did not propose in the CAIR NPR that States be required to impose an emissions cap on those sources, but instead solicited comment on the issue, EPA proposed in the CAIR SNPR that States be required to impose an emissions cap in certain cases on non-EGU sources. (See discussion in VII.A.1 of today's preamble.)

If a State chooses to obtain some, but not all, of its required reductions for SO_2 or NO_X emissions from non-EGUs, it would still be required to set an EGU budget for SO_2 or NO_X respectively, but it would set such a budget at some level higher than shown in Tables V–1, V–2, or V–4 in today's preamble, thus allowing more emissions from EGUs. The difference between the amount of a State's SO_2 budget in Table V–1 and a State's selected higher EGU SO_2 budget would be the amount of SO_2 emissions reductions the State demonstrates it will achieve from non-EGU sources. By the same token, the difference between the amount of a State's annual NO_X budget in Table V–2 and a State's selected higher annual EGU NO_X budget would be the amount of annual NO_X emissions reductions the State demonstrates it will achieve from non-EGU sources.[109] Further, the difference between the amount of a State's seasonal NO_X budget in Table V–4 and a State's selected higher ozone season EGU NO_X budget would be the amount of ozone season NO_X emissions reductions the State demonstrates it will achieve from non-EGU sources.

Special Concerns About SO_2 Allowances

In the case where a State requires a portion of its SO_2 emissions reductions from non-EGU sources and a portion from EGUs, there remains a concern about the impact of excess title IV allowances above a State's EGU cap, particularly on the operation of the title IV SO_2 cap and trade program. Consequently, today, we are adopting the requirement that these States include a mechanism for retirement of the allowances in excess of the State's SO_2 budget.

Like a State choosing to control only EGUs but not to participate in the trading program, a State that chooses to control non-EGUs and EGUs must adopt a mechanism for retiring surplus title IV allowances. The number of title IV allowances that must be retired is equal to the difference between the number of title IV allowances allocated to EGUs in that State and the SO_2 budget the State sets for EGUs under this rule. If the State uses a retirement mechanism (as discussed in VII.A.2.d.) in which a source surrendering allowances under the title IV SO_2 cap and trade program surrenders more allowances than otherwise required under title IV, the total number of allowances surrendered per ton of emissions in this case will be less than 2 to 1 in Phase 1 and less than 2.86 to 1 in Phase 2. This is because the non-EGUs will control to achieve a portion of the CAIR SO_2 reduction required, and so there will be a smaller surplus of title IV allowances than if all the required reductions were achieved by EGUs. The appropriate retirement factor will equal two times the State's SO_2 budget in Phase I or 2.86 times the State's SO_2 budget in Phase II as noted in Table V–1 of the budget section, divided by the State's selected higher EGU SO_2 budget (taking into account non-EGU reductions). The factor could then be used as the EGU retirement ratio for compliance purposes in a scenario where a State has decided to control SO_2 emissions from EGUs through a mechanism other than the EPA-administered trading program.

A simplified example can help illustrate this. Let us assume a State's sources were allocated a total of 200 allowances under title IV. Under CAIR, in Phase I, the State's reduction requirement would thus be 100 tons. Suppose this State decided that 25 tons would be reduced by non-EGUs and the remaining 75 tons would be reduced by the EGUs. (The State's budget for EGUS would increase to 125 tons.) The State would also need to retire 75 excess title IV allowances. This could be accomplished by requiring each Acid Rain source to surrender a total of 1.6 vintage 2010 through 2014 allowances (200 allowances allocated in the State/ 125 tons in State EGU budget) per ton of SO_2 emissions. The allowances surrendered would satisfy the Acid Rain Program requirement of surrendering one allowance per ton of emissions, as well as achieving the additional retirement requirement under CAIR since 200 allowances would be used for EGUs to emit the EGU budget of 125 tons of SO_2. (Pre-2010 allowances continue to be available for use on a one-allowance-per-ton-of-emissions basis here as in other situations.)

This is consistent with EPA's overall approach. If this same State decided to get all reductions (i.e., 100 tons) from EGUs, the State would require EGUs to retire 100 additional allowances by surrendering a total of 2 vintage 2010 through 2014 allowances (200 allowances allocated in the State/100 tons in State EGU budget) per ton of SO_2 emissions.

The demonstration of emissions reductions from non-EGUs is a critical requirement of the SIP revision due from a State that chooses to control non-EGUs. The State must take into account the amount of emissions attributable to the source category in both (i) the base case, in the implementation years 2010 and 2015, i.e., without assuming any SIP-required reductions under the CAIR from non-EGUs; and (ii) in the control case, in the implementation years 2010 and 2015, i.e., assuming SIP-required reductions under the CAIR from non-EGUs. We proposed an alternative methodology for calculating the base case for certain large non-EGU sources, as described below, but generally the difference between emissions in the base case and emissions in the control

[109] In the CAIR SNPR, EPA mistakenly cited the EGU budget numbers from Tables VI–9 and VI–10 in the CAIR NPR (69 FR 4619–20) when it should have cited Tables II–1 and II–2 in the CAIR SNPR. The EPA used the correct numbers, however, in the proposed regulatory text in the CAIR SNPR (69 FR 32729–30 and 69 FR 32733–34 (§§ 51.123(e)(2) and 51.124(e)(2)).

case equals the amount of emissions reductions that can be claimed from application of the controls on non-EGUs. (See discussion later in this section for criteria applicable to development of the baseline and projected control emissions inventories.)

States that meet the lesser of their CAIR ozone season NO_X budget or NO_X SIP Call EGU trading budget using the CAIR ozone season NO_X trading program also satisfy their NO_X SIP Call requirements for EGUs. States may also choose to include all of their NO_X SIP Call non-EGUs in the CAIR ozone season NO_X program at their NO_X SIP Call levels (i.e., the non-EGU trading budget remains the same).

To the extent EPA allows through the Regional Haze Rule and a State then chooses to use EPA analysis to show that CAIR reductions from EGUs meet BART requirements, States that achieve a portion of their CAIR reductions from sources other than EGUs and wanting to show that even with those reductions the EGUs will meet BART requirements must make a supplemental demonstration that BART requirements are satisfied.

b. Eligibility of Non-EGU Reductions

In the CAIR SNPR, EPA proposed that, in evaluating whether emissions reductions from non-EGUs would count towards the emissions reductions required under the CAIR, States may only include reductions attributable to measures that are not otherwise required under the CAA. Specifically, EPA proposed that States must exclude non-EGU reductions attributable to measures otherwise required by the CAA, including: (1) Measures required by rules already in place at the date of promulgation of today's final rule, such as adopted State rules, SIP revisions approved by EPA, and settlement agreements; (2) measures adopted and implemented by EPA (or other Federal agencies) such as emissions reductions required pursuant to the Federal Motor Vehicle Control Program for mobile sources (vehicles or engines) or mobile source fuels, or pursuant to the requirements for National Emissions Standards for Hazardous Air Pollutants; and (3) specific measures which are mandated under the CAA (which may have been further defined by EPA rulemaking) based on the classification of an area which has been designated nonattainment for a NAAQS, such as vehicle inspection and maintenance programs.

In discussing this proposal, EPA noted that States required to make CAIR SIP submittals may also be required to make separate SIP submittals to meet other requirements applicable to non-EGUs, *e.g.*, nonattainment SIPs required for areas designated nonattainment under the $PM_{2.5}$ or 8-hour ozone NAAQS or regional haze SIPs. The EPA noted it is likely that CAIR SIP submittals will be due before or at the same time as some of these other SIP submittals. We therefore proposed that States relying on reductions from controls on non-EGUs must commit in the CAIR SIP revisions to replace the emissions reductions attributable to any CAIR SIP measure if that measure is subsequently determined to be required to meet any other SIP requirement.

Some commenters objected to the proposed exclusion of credit for measures which are mandated under the CAA based on the classification of an area which has been designated nonattainment for a NAAQS, as well as to the proposed requirement that such measures must be replaced if they are later determined to be required in meeting separate SIP requirements. These commenters reasoned that such a requirement would not be applied to EGUs and would impose unnecessary and costly burdens on non-EGUs, thus creating an incentive for States to avoid controlling non-EGUs and to impose all CAIR reduction requirements on EGUs. One commenter further objected that, as long as a measure was not included in the base case EPA used to determine a State's contribution to other States' nonattainment under CAA section 110(a)(2)(D), there is no justification for excluding CAIR credit for such measure, and that EPA's proposed exclusion of credit for any measure ''otherwise required by the CAA'' is inconsistent with the NO_X SIP Call.

In response to these comments, EPA agrees that it is not appropriate to apply this proposed restriction inconsistently to EGUs and non-EGUs. Thus, EPA is adopting a modified form of the proposed criteria for the eligibility of non-EGU emissions reductions, eliminating the requirement that States must exclude non-EGU reductions attributable to measures otherwise required by the CAA based on the classification of an area which has been designated nonattainment for a NAAQS. Consequently, the final rule allows credit for measures that a State later adopts in response to requirements which result from an area's nonattainment classification, such as reasonably available control technology (RACT). With this change, all emissions reductions are eligible for credit in meeting CAIR except: (1) Measures adopted or implemented by the State as of the date of promulgation of today's final rule, such as adopted State rules, SIP revisions approved by EPA, and settlement agreements; and (2) measures adopted or implemented by the Federal government (*e.g.*, EPA or other Federal agencies) as of the date of submission of the SIP revision by the State to EPA, such as emissions reductions required pursuant to the Federal Motor Vehicle Control Program for mobile sources (vehicles or engines) or mobile source fuels, or pursuant to the requirements for National Emissions Standards for Hazardous Air Pollutants.

This exclusion of credit is consistent with EPA's approach in the NO_X SIP Call, although a direct comparison of the creditability requirements in the CAIR and in the NO_X SIP Call is not possible due to the timing and context in which both rules were developed. The NO_X SIP Call used statewide budgets for all sources as an accounting tool to determine the adequacy of a strategy, while the CAIR takes a different approach in which baseline emission inventories for non-EGU sectors will, if needed, be developed later. The NO_X SIP Call did, as does the CAIR, restrict States from taking credit for any Federal measures adopted after promulgation of the rule (63 FR 57427–28). It also did not allow credit for already adopted measures, but the timing of the NO_X SIP Call was such that nonattainment planning measures would have already likely been adopted as the SIP deadlines for adoption of such measures had passed. In today's action, nonattainment planning measures adopted after the promulgation of today's rule will be allowed credit under CAIR.

In order to take credit for CAIR reductions from non-EGUs, the reductions must be beyond what is required under the NO_X SIP Call. That is, a reduction must be in the non-ozone season or it must be beyond what is expected in the ozone season. Non-ozone season reductions must also be beyond what is in the base case, particularly for units that have low NO_X burners and certain SCRs (*e.g.*, ones required to be run annually). The reductions must be in addition to those already expected. If ozone season reductions are considered, the non-EGU NO_X SIP Call trading budget must be adjusted by the increment of CAIR reductions beyond the levels in the NO_X SIP Call. This removes the corresponding allowances from the market and ensures that the emissions do not shift to other sources.

After evaluating the eligibility of non-EGU reductions in accordance with the requirements discussed here, States must exclude credit for ineligible measures by (i) including such measures in both the baseline and controlled emissions inventory cases, if they have already been adopted; or (ii) excluding them from both the base and control emissions inventory cases if they have not yet been adopted. (*See* discussion later in this section regarding development of emissions inventories and demonstration of non-EGU reductions.)

c. Emissions Controls and Monitoring

As noted in section VII.A.1., we modified the ''hybrid'' approach described in the CAIR NPR as it applies to certain non-EGUs, and adopt today the approach described in the CAIR SNPR. Specifically, for States that choose to impose controls on large industrial boilers and turbines, *i.e.*, those whose maximum design heat input is greater than 250 mmBtu/hr, to meet part or all of their emissions reductions requirements under the CAIR, State rules must include an emissions cap on all such sources in their State. Additionally, in this situation, States must require those large industrial boilers and turbines to meet part 75 requirements for monitoring and reporting emissions as well as recordkeeping. This ensures consistency in measurement and certainty of reductions and has been proven technologically and economically feasible in other programs.

If a State chooses to control non-EGUs other than large industrial boilers and turbines to obtain the required emissions reductions, the State must either (i) impose the same requirements, *i.e.*, an emissions cap on total emissions from non-EGUs in the source category in the State and part 75 monitoring, reporting and recordkeeping requirements; or (ii) demonstrate why such requirements are not practicable. In the latter case, the State must adopt appropriate alternative requirements to ensure that emissions reductions are being achieved using methods that quantify those emissions reductions, to the extent practicable, with the same degree of assurance that reductions are being quantified for EGUs and non-EGU boilers and turbines using part 75 monitoring. This is to ensure that, regardless of how a State chooses to meet the CAIR emissions reduction requirements, all reductions made by States to comply with the CAIR have the same, high level of certainty as that achieved through the cap and trade approach. Further, if a State adopts alternative requirements that do not apply to all non-EGUs in a particular source category (defined to include all sources where any aspect of production of one or more such sources is reasonably interchangeable with that of one or more other such sources), the State must demonstrate that it has analyzed the potential for shifts in production from the regulated sources to unregulated or less stringently regulated sources in the same State as well as in other States and that the State is not including reductions attributable to sources that may shift emissions to such unregulated or less regulated sources.

d. Emissions Inventories and Demonstrating Reductions

To quantify emissions reductions attributable to controls on non-EGUs, the States must submit both baseline and projected control emissions inventories for the applicable implementation years. We have issued many guidance documents and tools for preparing such emissions inventories, some of which apply to specific sectors States may choose to control.[110] While much of that guidance is applicable to today's rulemaking, there are some key differences between quantification of emissions reduction requirements under a SIP designed to help achieve attainment with a NAAQS and emissions reduction requirements under a SIP designed to reduce emissions that contribute significantly to a downwind State's nonattainment problem or interfere with maintenance in a downwind State. Because States are taking actions as a result of their impact on other States, and because the impacted States have no authority to reduce emissions from other States, the emissions reduction estimates become even more important. (For a complete discussion, see 69 FR 32693; June 10, 2004.)

Specifically, when we review CAIR SIPs for approvability, we intend to review closely the emissions inventory projections for non-EGUs to evaluate whether emissions reduction estimates are correct. We intend to review the accuracy of baseline historical emissions for the subject sources, assumptions regarding activity and emissions growth between the baseline year and 2010[111] and 2015, and assumptions about the effectiveness of control measures.

Before describing the specific steps involved in this quantification process, EPA notes that a few commenters objected to the proposed requirements as arbitrary restrictions intended to discourage States' discretion in imposing control measures on non-EGUs since these requirements would use what the commenters describe as extremely conservative emissions baseline and emissions reduction estimates. No commenter refuted EPA's explanation, noted above, of the need for stringent requirements to ensure greater accuracy of emission inventories and greater certainty of reduction estimates used in SIPs addressing transported pollutants. The EPA maintains that the need for more accurate inventories and more certain reduction estimates justifies the requirements discussed below. Further, no commenter provided an alternate method of addressing EPA's concerns about the development of such inventories and reduction estimates. Thus, EPA is finalizing its proposed approach.

i. Historical Baseline

To quantify non-EGU reductions, as the first step, a historical baseline must be established for emissions of SO_2 or NO_X from the non-EGU source(s) in a recent year. The historical baseline inventory should represent actual emissions from the sources prior to the application of the controls. We expect that States will choose a representative year (or average of several years) during 2002–2005 for this purpose.

The requirements for estimating the historical baseline inventory that follow reflect EPA's view that, when States assign emissions reductions to non-EGU sources, achievement of those reductions should carry a high degree of certainty, just as EGU reductions can be quantified with a high degree of certainty in accordance with the applicable part 75 monitoring requirements. Because the non-EGU emissions reductions are estimated by subtracting controlled emissions from a projected baseline, if the historical baseline overestimates actual emissions, the estimated reductions could be higher than the actual reductions achieved.

For non-EGU sources that are subject to part 75 monitoring requirements, historical baselines must be derived from actual emissions obtained from part 75 monitored data. For non-EGU sources that do not have part 75 monitoring data, historical baselines must be established that estimate actual

[110] The many EPA guidance documents and tools for preparing emission inventory estimates for SO_2 and NO_X are available at the following Web sites: *http://www.epa.gov/ttn/chief/net/general.html*, *http://www.epa.gov/ttn/chief/eiip/techreport/*, *http://www.epa.gov/ttn/chief/publications.html#general*, *http://www.epa.gov/ttn/chief/software/index.html*, and *http://www.epa.gov/ttn/chief/efinformation.html*.

[111] The 2010 modeling date is relevant for both SO_2 and NO_X even though NO_X requirements begin in 2009. See Section IV for discussion.

emissions in a way that matches or approaches as closely as possible the certainty provided by the part 75 measured data for EGUs. For these sources, States must estimate historical baseline emissions using source-specific or category-specific data and assumptions that ensure a source's or source category's actual emissions are not overestimated.

To determine the baseline for sources that do not have part 75 measured data, States must use emission factors that ensure that emissions are not overestimated (*e.g.*, emission factors at the low end of a range when EPA guidance presents a range) or the State must provide additional information that shows with reasonable confidence that another value is more appropriate for estimating actual emissions. Other monitoring or stack testing data can be considered, but care must be taken not to overestimate baselines. If a production or utilization factor is part of the historical baseline emissions calculation, a factor that ensures that emissions are not overestimated must be used, or additional data must be provided. Similarly, if a control or rule effectiveness factor enters into the estimate of historical baseline emissions, such a factor must be realistic and supported by facts or analysis. For these factors, a high value (closer to 100 percent control and effectiveness) ensures that emissions are not overestimated.

ii. Projections of 2010 and 2015 Baselines

The second step in quantifying SO_2 or NO_X emissions reductions for non-EGUs is to use the historical baseline emissions and project emissions that would be expected in 2010 and 2015 without the CAIR. This step results in the 2010 and 2015 baseline emissions estimates.

The EPA proposed and requested comment on two procedures for estimating the future baselines: one relies on projections based on a number of estimated parameters; the second uses the lower of this projection and actual historical emissions. Today, EPA finalizes the second approach for determining 2010 and 2015 emissions baselines.

To estimate future emissions, States must use state-of-the-art methods for projecting the source or source category's economic output. Economic and population forecasts must be as specific as possible to the applicable industry, State, and county of the source and must be consistent with both national projections and relevant official planning assumptions, including estimates of population and vehicle miles traveled developed through consultation between State and local transportation and air quality agencies. However, if these official planning assumptions are themselves inconsistent with official U.S. Census projections of population or with energy consumption projections contained in the most recent Annual Energy Outlook published by the U.S. Department of Energy, then adjustments must be made to correct the inconsistency, or the SIP must demonstrate how the official planning assumptions are more accurate. If the State expects changes in production method, materials, fuels, or efficiency to occur between the baseline year and 2010 or 2015, the State must account for these changes in the projected 2010 and 2015 baseline emissions. For example, if a source has publicly announced a change or applied for a permit for a change, it should be reflected in the projections. The projection must also reflect any adopted regulations that are ineligible control measures and that will affect source emissions.

As stated above, EPA is requiring States to use the lower of historical baseline emissions or projected 2010 or 2015 emissions, as applicable, for a source category. This is because changes in production method, materials, fuels, or efficiency often play a key role in changes in emissions. Because of factors such as these, emissions can often stay the same or even decrease as productivity within a sector increases. These factors that contribute to emission decreases can be very difficult to quantify. Underestimating the impact of these types of factors can very easily result in a projection for increased emissions within a sector, when a correct estimate will result in a projection for decreased emissions within the sector. A few commenters opposed this methodology as arbitrary but failed to explain why EPA's concerns, as described above, are not valid. Commenters also failed to propose other methodologies for addressing these concerns. Thus, EPA is finalizing the use of this second methodology.

iii. Controlled Emissions Estimates for 2010 and 2015

The third step is to develop the 2010 and 2015 controlled emissions estimates by assuming the same changes in economic output and other factors listed above but adding the effects of the new controls adopted for the purpose of meeting the CAIR. The controls may take the form of regulatory requirements, *e.g.*, emissions caps, emission rate limits, technology requirements, or work practice requirements. The State's estimate of the effect of the control regulations must be realistic in light of the specific provisions for monitoring, reporting, and enforcement and experience with similar regulatory approaches.

In addition, the State's analysis must examine the possibility that the controls may cause production and emissions to shift to unregulated or less stringently regulated sources in the same State or another State. If all sources of a source category (defined to include all sources where any aspect of production is reasonably interchangeable) within the State are regulated with the same stringency and compliance assurance provisions, the analysis of production and emissions shifts need only consider the possibility of shifts to other States. If only a portion of a source category within a State is regulated, the analysis must also include any in-State shifting. In estimating controlled emissions in 2010 and 2015, assumptions regarding control measures that are not eligible for CAIR reduction credit must be the same as in the 2010 and 2015 baseline estimates. For example, a State may not take credit for reductions in the sulfur content of nonroad diesel fuel that are required under the recent Federal nonroad fuel rule (69 FR 38958; June 29, 2004). By including the effect of this Federal rule in both the baseline and controlled emissions estimates for 2010 and 2015, the State will appropriately exclude this ineligible reduction when it subtracts the controlled emissions estimates from the baseline emissions estimates.

The method that we are adopting today specifies the 2010 and 2015 emissions reductions which can be counted toward satisfying the CAIR. The method requires the use of the historical baseline or the baseline emission estimates, whichever is lower. That is, the reduction is calculated as follows: (i) For 2010, the difference between the lower of historical baseline or 2010 baseline emissions estimates and the 2010 controlled emissions estimates, minus any emissions that may shift to other sources rather than be eliminated; and (ii) for 2015, the difference between the lower of historical baseline or 2015 baseline emissions estimates and the 2015 controlled emissions estimates, minus any emissions that may shift to other sources rather than be eliminated.

4. Controls on Non-EGUs Only

Although we stated that we believe it is unlikely States may choose to control only non-EGUs, we proposed in the CAIR SNPR provisions for determining the specified emissions reductions that must be obtained if States pursue this alternative, and we adopt those provisions today. The reason we think it is unlikely is based on States' emissions profiles. Most SO_2 emissions are from EGUs and therefore it is unlikely that a State can achieve the required emissions reductions without regulating EGUs to some degree. In addition, SO_2 emissions reductions from EGUs are highly cost effective. States that choose this path must ensure that the amount of non-EGU reductions is equivalent to all of the emissions reductions that would have been required from EGUs had the State chosen to assign all the emissions reductions to EGUs. For SO_2 emissions, this amount in 2010 would be 50 percent of a State's title IV SO_2 allocations for all units in the State and, for 2015, 65 percent of such allocations. For NO_X emissions, this amount would be the difference between a State's EGU budget for NO_X under the CAIR and its NO_X baseline EGU emissions inventory as projected in the Integrated Planning Model (IPM) for 2010 and 2015, respectively.[112]

In addition, the same requirements described elsewhere in this part of today's preamble regarding the eligibility of non-EGU reductions, emissions control and monitoring, emissions inventories and demonstration of reductions, will apply to the situation where a State chooses to control only non-EGUs.

5. Use of Banked Allowances and the Compliance Supplement Pool

In the CAIR NPR, EPA stated that States may allow EGUs to demonstrate compliance with the State EGU SO_2 budget by using title IV allowances (i) that were banked, or (ii) that were obtained in the current year from sources in other States (69 FR 4627). The EPA adopts this provision in today's action. The EPA adopts a similar provision for the use of banked NO_X SIP Call allowances (pre-2009) to demonstrate compliance with the State EGU ozone season NO_X budget. See also the CAIR NPR (69 FR 4633). Therefore, State rules may allow the use of pre-2010 title IV and pre-2009 NO_X SIP Call allowances banked in the title IV and NO_X SIP Call trading programs for compliance in the CAIR. States participating in the EPA-administered CAIR trading programs must allow the use of these pre-2010 title IV allowances or pre-2009 NO_X SIP Call allowances in accordance with EPA's model trading rules.

Additionally, States with annual NO_X reduction requirements may use compliance supplement pool (CSP) allowances as described in sections V and VIII. Distribution of the CSP is essentially the same as the process used in the NO_X SIP Call, through one or both of two mechanisms. States may distribute CSP allowances on a pro-rata basis to sources that implement NO_X control measures resulting in reductions in 2007 or 2008 that are beyond what is required by any applicable State or Federal emissions limitation (early reductions). The second CSP distribution mechanism that a State can use is to issue CSP allowances based on the demonstration of a need for an extension of the 2009 deadline for implementing emission controls. The demonstration must show unacceptable risk either to a source's own operation or its associated industry—for EGUs, power supply reliability, for non-EGUs risk comparable to that described for the electricity industry. See also 63 FR 57356 for further discussion of these points.

Pre-2010 title IV SO_2 allowances, pre-2009 NO_X SIP Call allowances and CAIR annual NO_X CSP allowances can all be counted toward a States efforts to achieve its CAIR reduction obligations regardless of whether the CAIR trading programs are used or not.

B. State Implementation Plan Schedules

1. State Implementation Plan Submission Schedule

In the NPR, we proposed to require States to submit SIPs to address interstate transport in accordance with the provisions of this rule approximately 18 months from the date of this final rule (69 FR 4624). After careful consideration of the comments we received concerning this issue, we have concluded that States should submit SIPs to satisfy this final rule as expeditiously as possible, but no later than 18 months from the date of today's action. Under this schedule, upwind States' transport SIPs to meet CAA section 110(a)(2)(D) will be due before the downwind States' $PM_{2.5}$ and 8-hour ozone nonattainment area SIPs under CAA section 172(b). We expect that the downwind States' 8-hour ozone nonattainment area SIPs will be due by June 15, 2007, and their $PM_{2.5}$ nonattainment SIPs will be due by April 5, 2008.[113]

We believe that this sequence for SIP submissions to address upwind interstate transport and downwind nonattainment areas is consistent both with the applicable provisions of the CAA and with sound policy objectives. The CAA provides for this sequence of submissions in section 110(a)(1) and (a)(2), which provide that the submittal period for SIPs required by section 110(a)(2)(D) runs from the earlier date of the NAAQS revision, and in section 172(b), which provides that the submittal period for the nonattainment area SIPs runs from the later date of designation. Clean Air Act section 110(a)(1) requires each State to submit a SIP to EPA ''within 3 years * * * after the promulgation of a [NAAQS] (or any revision thereof).'' Section 110(a)(2) makes clear that this SIP must include, among other things, provisions to address the requirements of section 110(a)(2)(D). We read these provisions together to require that each upwind State must submit, within 3 years of a new or revised NAAQS, SIPs that address the section 110(a)(2)(D) requirement. By contrast, the schedule provided in section 172(b) is only applicable to the nonattainment area SIP requirements.

Section 110(a) imposes the obligation upon States to make a submission, but the contents of that submission may vary depending on the facts and circumstances. In particular, the data and analytical tools available at the time the section 110(a)(2)(D) SIP is developed and submitted to EPA necessarily affect the content of the submission. Where, as here, the data and analytical tools to identify a significant contribution from upwind States to nonattainment areas in downwind States are available, the State's SIP submission must address the existence of the contribution and the emission reductions necessary to eliminate the significant contribution. In other circumstances, however, the tools and information may not be available. In such circumstances, the section 110(a)(2)(D) SIP submission should indicate that the necessary information is not available at the time the submission is made or that, based on the information available, the State believes that no significant contribution to downwind nonattainment exists. EPA can always act at a later time after the initial section 110(a)(2)(D) submissions to issue a SIP call under section 110(k)(5) to States to revise their SIPs to provide for additional emission controls to satisfy the section 110(a)(2)(D) obligations if such action were

[112] See ''Technical Support Document for the Clean Air Interstate Rule Notice of Final Rulemaking; Regional and State SO_2 and NO_X Emissions Budgets'' for tables containing information to calculate these amounts for both SO_2 and NO_X.

[113] By statute, the date for submission of nonattainment area SIPs is to be no later than 3 years from the date of nonattainment designation. Section 172(b).

warranted based upon subsequently-available data and analyses. This is precisely the circumstance that was presented at the time of the NO_X SIP Call in 1998 when EPA issued a section 110(k)(5) SIP call to states regarding their section 110(a)(2)(D) obligations on the basis of new information that was developed years after the States' SIPs had been previously approved as satisfying section 110(a)(2)(D) without providing for additional controls since the information available at the earlier point in time did not indicate the need for such additional controls.

Not only is this sequencing consistent with the CAA, it is consistent with sound policy considerations. The upwind reductions required by today's action will facilitate attainment planning by the States affected by transport downwind. Rather than being ''premature'' as some commenters suggested, EPA's understanding of the data and models leads the Agency to believe that requiring the States to address the upwind transport contribution to downwind nonattainment earlier in the process as a first step is a reasonable approach and is fully consistent with the statutory structure. This approach will allow downwind States to develop SIPs that address their share of emissions with knowledge of what measures upwind States will have adopted. In addition, most of the downwind States that will benefit by today's rulemaking are themselves significant contributors to violations of the standards further downwind and, thus, are subject to the same requirements as the States further upwind. The reductions these downwind States must implement due to their additional role as upwind States will help reduce their own $PM_{2.5}$ and 8-hour ozone problems on the same schedule as emissions reductions for the upwind States. We believe that providing 18 months from the date of today's action for States to submit the transport SIPs required by this rule is appropriate and reasonable, for the reasons discussed more fully below.

a. The EPA's Authority To Require Section 110(a)(2)(D) Submissions in Accordance With the Schedule of Section 110(a)(1)

A number of commenters objected to EPA's proposal to require States to submit the transport SIPs on the schedule set forth in section 110(a)(1). The commenters argued that section 110(a)(1) does not apply to the requirements of section 110(a)(2)(D), because the former refers to plans that States must adopt ''to implement, maintain, and enforce'' the NAAQS ''within'' the State, whereas the latter refers to plans that prevent emissions that affect nonattainment or maintenance of the NAAQS in places outside the State. According to the commenters, because section 110(a)(1) SIPs purportedly need not address the interstate transport issues governed by section 110(a)(2)(D), the States have no current obligation to prevent such interstate transport and, by extension, there is no basis for the CAIR at this time.

The EPA disagrees with the commenters. A State's SIP must of course provide for ''implementation, maintenance, and enforcement'' of the NAAQS ''within'' the State because States lack authority to impose requirements on sources in other States; *i.e.*, any plan submitted by a State will necessarily be applicable to sources ''within'' that State. The CAA, however, also requires that such SIPs must be submitted to EPA no later than three years after promulgation of a new or revised NAAQS and must contain adequate provisions regarding interstate transport from emission sources within the State in compliance with section 110(a)(2)(D). The explicit terms of the statute provide for the State submission of initial SIPs after promulgation of a new NAAQS, and provide that such SIPs should address interstate transport. Section 110(a)(1) provides that:

> [e]ach State shall * * * adopt and submit to the Administrator, within 3 years (or such shorter period as the Administrator may prescribe) after the promulgation of a national primary ambient air quality standard (or any revision thereof) * * * a plan which provides for implementation, maintenance, and enforcement of such primary standard in each [area] within such State.

Section 110(a)(2) provides, in relevant part, that:

> [e]ach implementation plan submitted by a State under this Act shall be adopted by the State after reasonable notice and public hearing. Each such plan shall * * * (D) contain adequate provisions—(i) prohibiting * * * any source or other type of emissions activity within the State from emitting any air pollutant in amounts which will—(I) contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to [the NAAQS].

By referencing each implementation plan in section 110(a)(2), it is clear that the implementation plans required under section 110(a)(1) must satisfy the requirements of section 110(a)(2)(D). Thus, the plain meaning of these provisions, read together, is that SIP submissions are required within 3 years of promulgation of a new or revised NAAQS, and that the SIP submissions must meet the requirements of section 110(a)(2)(D).

By contrast, other requirements of section 110(a)(2) are not triggered by EPA's promulgation of a new or revised NAAQS, but rather by EPA's final designation of nonattainment areas. For example, section 110(a)(2)(I) by its terms indicates that State SIPs must meet that requirement not on the schedule of section 110(a)(1), but instead on the schedule of section 172(b).

The explicit distinction in the statute between requirements that States must meet on the schedule of section 110(a)(1) versus the schedule of section 172(b) reinforces the conclusion that States are to meet the initial requirements of section 110(a)(2)(D) within the schedule of section 110(a)(1).

In this context, it is important to note that the requirements of section 110(a)(1) plans are not limited to areas designated attainment, nonattainment, or unclassifiable.[114] Section 110(a)(1) requires each State to develop and submit a plan that provides for the implementation, maintenance, and enforcement of the NAAQS in ''each'' area of the State. Similarly, the requirement in section 110(a)(2)(D) that SIPs must prohibit interstate transport of air pollutants that significantly contribute to downwind nonattainment is not limited to any particular category of formally designated areas in the State. The provisions apply to emissions activities that occur anywhere in a state, regardless of its designation. If, as the commenters suggested, the requirements of section 110(a)(2)(D) plans are governed not by section 110(a)(1), but rather by the schedule of section 172, that would lead to the absurd result that upwind States need only reduce emissions from designated nonattainment areas to prevent significant contribution to nonattainment or interference with maintenance in a downwind State. Given that large portions of many upwind States may be designated as attainment for the NAAQS for local purposes, yet still contain large sources of emissions that affect downwind States through interstate transport, EPA believes that Congress could not have intended the prohibitions of section 110(a)(2)(D) to apply only to nonattainment areas in upwind States.[115] Indeed, the language of

[114] Under section 107(d), EPA is required to identify all areas of each State as falling into one of these three categories.

[115] The EPA notes that under the provisions of section 107(d), certain portions of an upwind State that are monitoring attainment may be designated nonattainment because they contribute to violations of the NAAQS in a ''nearby'' area. Nevertheless,

section 110(a)(2) itself does not support such an interpretation. Therefore, the alternative schedule provided in section 172(b) applicable only to nonattainment areas cannot be the schedule that governs the State submission of transport SIPs. This leaves the schedule of section 110(a)(1) as the only appropriate schedule in the case of SIPs following EPA promulgation of new or revised NAAQS.

The commenters also disputed that the schedule of section 110(a)(1) applies to the section 110(a)(2)(D) requirement because there are other elements of section 110(a)(2) that States could not meet on that schedule. As an example, the commenters pointed to section 110(a)(2)(I) which requires States to meet certain obligations imposed upon designated nonattainment areas. As formal designation under the generally applicable provisions of section 107(d) could take up to 3 years following promulgation of a new or revised NAAQS, and section 172(b) allows up to 3 additional years for State submission of nonattainment area SIPs, the commenters concluded that States could not meet section 110(a)(2)(I) on the schedule of section 110(a)(1). From the fact that States could not meet all of the elements of the section 110(a)(2) requirement within 3 years, the commenters inferred that EPA cannot require States to meet any of the requirements in section 110(a)(2), including section 110(a)(2)(D).

The EPA disagrees with the commenters' approach to the interpretation of the statute. The EPA agrees that there are certain provisions of section 110(a)(2) that are governed not by the schedule of section 110(a)(1), but instead by the timing requirement of section 172(b), *e.g.*, section 110(a)(2)(I). Other items in section 110(a)(2), however, do not depend upon prior designations in order for States to develop a SIP to begin to comply with them, *e.g.*, section 110(a)(2)(B) (pertaining to monitoring); section 110(a)(2)(E) (stipulating that States must provide for adequate resources); and section 110(a)(2)(K) (pertaining to modeling).

Most important, section 110(a)(2)(D) itself does not apply only to impacts on downwind nonattainment areas, and thus does not presuppose prior designations in either upwind or downwind States, or suggest that section 110(a)(2)(D) is somehow inapplicable until the submission of nonattainment area plans. By its explicit terms, section 110(a)(2)(D) requires States to prohibit emissions from "any source or other types of emissions activity within the State" that "contribute to nonattainment in, or interfere with maintenance by" any other State. A plain reading of the statute indicates that the emissions at issue can emanate from any portion of an upwind State and that the impacts of concern can occur in any portion of the downwind State.

While EPA agrees that there is overlap between the submission requirements of sections 110(a)(1) and (a)(2) and section 172(c), EPA believes that the plain language of these sections requires States to submit plans that comply with section 110(a)(2)(D) prior to the deadline for nonattainment area SIPs established by section 172, and that there is nothing that compels a contrary conclusion in the language of section 172. Section 172(b) provides that State plans for nonattainment areas must meet "*the applicable* requirements of [section 172(c)] and section 110(a)(2)" (emphasis added). Thus, the statute itself explicitly indicates that the State submissions for nonattainment plans must meet those requirements of section 110(a)(2) that are "applicable," not each requirement regardless of applicability. In the current situation, EPA believes that it is appropriate to view the CAA as requiring States to make a submission to meet the requirement of section 110(a)(2)(D) in accordance with the schedule of section 110(a)(1), rather than under the schedule for nonattainment SIPs in section 172(b).[116]

b. The EPA's Authority To Require Section 110(a)(2)(D) Submissions Prior to Formal Designation of Nonattainment Areas Under Section 107

A number of commenters argued that EPA has no authority to require States to comply with section 110(a)(2)(D) until after EPA formally designates nonattainment areas for the $PM_{2.5}$ and 8-hour ozone NAAQS.[117] These commenters claimed that section 107(d) and provisions of the Transportation Equity Act for the 21st Century (TEA–21) governing the designation of $PM_{2.5}$ and 8-hour ozone nonattainment areas preclude EPA from interpreting the CAA to require States to submit SIPs that comply with section 110(a)(2)(D) on the schedule contemplated by section 110(a)(1). In the view of the commenters, EPA could not reasonably expect States to determine whether and to what extent their in-State sources significantly contributed to nonattainment in other States within the initial 3-year timeframe, in advance of nonattainment area designations. According to the commenters, section 107(d) and TEA–21 negate the timing requirements of section 110(a)(1), so that States have no current obligation to address interstate transport and thus there is no basis for today's action.

The EPA disagrees with the commenters' view of the interaction of section 110 and section 107(d). The statute does not require EPA to have completed the designations process before the Agency or a State could assess the existence of, or extent of, significant contribution from one State to another. In addition, the technical approach by which EPA determines significant contribution from upwind to downwind States does not depend upon the prior completion of the designation process.

The EPA believes that the statute does not compel the conclusion that States may postpone compliance with section 110(a)(2)(D) until some future point after completion of the designation process. As discussed above, a reading of the plain language of sections 110(a)(1) and 110(a)(2) indicates that States must adopt and submit a plan to EPA within 3 years after promulgation of a new or revised NAAQS (the same time at which designations are generally due under section 107), and that each

there will be portions of upwind States that include emissions sources that are not in designated nonattainment areas, whether because of local monitored nonattainment, or because of contribution to a nearby nonattainment area, yet these portions of the upwind State may contain sources that cause emissions that States must address to meet the requirements of section 110(a)(2)(D).

[116] As noted earlier, what will be needed to meet section 110(a)(2) may vary, depending upon the specific facts and circumstances surrounding a new or revised NAAQS. *See, e.g., Proposed Requirements for Implementation Plans and Ambient Air Quality Surveillance for Sulfur Oxides (Sulfur Dioxide) National Ambient Air Quality Standard*, 60 FR 12492, 12505 (March 7, 1995). In the context of a proposed 5-minute NAAQS for $S0_2$, EPA tentatively concluded that existing SIP provisions for the 24-hour and annual $S0_2$ NAAQS were probably sufficient to meet many elements of section 110(a)(2). The EPA did not explicitly discuss State obligations under section 110(a)(2)(D) for the 5-minute NAAQS in the proposal, but the nature of the pollutant, the sources, and the proposed NAAQS are such that interstate transport would not have been the critical regionwide concern that it is for the $PM_{2.5}$ and 8-hour ozone NAAQS. The EPA does not expect States to make SIP submissions establishing emission controls for the purpose of addressing interstate transport without having adequate information available to them.

[117] The EPA notes that the 8-hour ozone designations became effective on June 15, 2004, and that the $PM_{2.5}$ designations will become effective on April 5, 2005. The EPA believes that the issue raised by the commenters is thus moot with respect to both the 8-hour ozone and $PM_{2.5}$ nonattainment areas because those designations are now complete.

such plan must meet the applicable requirements of section 110(a)(2)(D).[118]

Significantly, neither section 110(a)(1) nor section 110(a)(2)(D) are limited to ''nonattainment'' areas. By their explicit terms, both provisions apply to all areas within the State, regardless of whether EPA has formally designated the areas as attainment, nonattainment, or unclassifiable, pursuant to section 107(d). As to causes, section 110(a)(2)(D) compels States to address any ''emissions activity within the State,'' not solely emissions from formally designated nonattainment areas, nor does it in any other terms suggest that designations of upwind areas must first have occurred. As to impacts, section 110(a)(2)(D) refers only to prevention of ''nonattainment'' in other States, not to prevention of nonattainment in designated nonattainment areas or any similar formulation requiring that designations for downwind nonattainment areas must first have occurred. By comparison, other provisions of the CAA do clearly indicate when they are applicable to designated nonattainment areas, rather than simply to nonattainment more generally (*e.g.*, sections 107(d)(1)(A)(i), 181(b)(2)(A), and 211(k)(10)(D)). Because section 110(a)(2)(D) refers only to ''nonattainment,'' not to ''nonattainment areas,'' EPA concludes that the section does not presuppose the existence of formally designated nonattainment areas, but rather to ambient air quality that does not attain the NAAQS.

The EPA believes that this plain reading of the provisions is also the most logical approach. A reading that section 110(a)(2)(D) means that States have no obligation to address interstate transport unless and until there are formally designated nonattainment areas pursuant to section 107 would be inconsistent with the larger goal of the CAA to encourage expeditious attainment of the NAAQS. In this immediate instance, currently available air quality monitoring data and modeling make it clear that many areas of the eastern portion of the country are in violation of both the $PM_{2.5}$ and 8-hour ozone NAAQS. Air quality modeling studies generally available to the States demonstrate that, and quantify the extent to which, SO_2 and NO_X emissions from sources in upwind States are contributing to violations of the $PM_{2.5}$ and 8-hour ozone NAAQS in downwind States.

Following the example of the NO_X SIP Call, EPA has an effective analytical approach to determine whether that interstate contribution is significant, in accordance with section 110(a)(2)(D). Thus, EPA currently has the information and tools that it needs to determine what the initial $PM_{2.5}$ and 8-hour ozone SIPs from upwind States should include as appropriate NO_X and SO_2 emissions reductions in order to prevent emissions that significantly contribute to nonattainment in downwind States. The designation process under section 107 is the means by which States and EPA decide the precise boundaries of the nonattainment areas in the downwind States. Both $PM_{2.5}$ and ozone are regional phenomena, however, and information as to the precise boundaries of nonattainment areas is not necessary to implement the requirements of section 110(a)(2)(D) for these pollutants. Consequently, it was not necessary for EPA to wait until after completion of formal designation of nonattainment area boundaries before undertaking this rulemaking. Moreover, EPA believes that taking action now will achieve public health protections more quickly as it will enable States to develop implementation plans more expeditiously and efficiently.

The EPA disagrees with the commenters' view of the relationship between section 110(a)(2) and section 107 and their apparent view of the method by which EPA analyzes whether there is a contribution from an upwind State to a downwind State, and whether that contribution is significant.

The EPA has, in this case, used the detailed data from the extensive network of air quality monitors to identify which States have monitors that are currently showing violations of the $PM_{2.5}$ and 8-hour ozone NAAQS. In the NPR, EPA stated that based upon data for the 3-year period from 2000–2002, ''120 counties with *monitors* exceed the annual $PM_{2.5}$ NAAQS and 297 counties with *monitor* readings exceed the 8-hour ozone NAAQS'' (69 FR 4566, 4581; January 30, 2004) (emphasis added). The geographic distribution of monitors with data registering current violations indicated that there is nonattainment of both the $PM_{2.5}$ and 8-hour ozone NAAQS throughout the eastern United States and in other portions of the country including California. For analyses of future ambient conditions, EPA used various modeling tools to predict that, in the absence of the CAIR, there would be counties with monitors that would continue to show violations of the $PM_{2.5}$ and 8-hour ozone NAAQS in 2010 and 2015. In subsequent steps, EPA analyzed whether the emissions from upwind States contributed to the ambient conditions at the monitors registering NAAQS violations in downwind States, and thereafter determined whether that contribution would be significant pursuant to section 110(a)(2)(D).

In none of these steps, however, did EPA need to know the precise boundaries of the nonattainment areas that may ultimately result from the section 107 designation process. The determination of attainment status in a given county is based primarily upon the monitored ambient measurements of the applicable pollutant in the county. Thus, it is the readings at the monitors that are the appropriate information for EPA to evaluate in assessing current and future interstate transport at that monitor in that county, not the exact dimensions of the area that may ultimately comprise the formally designated nonattainment area. The ultimate size of nonattainment areas will have a bearing on other components of the State's nonattainment area SIP. The size of such nonattainment areas, however, is not meaningful in assessing whether interstate transport from another State or States has an impact at a violating monitor, and whether the transport significantly contributes to nonattainment, that the other State or States should address to comply with section 110(a)(2)(D). Thus, EPA believes that basing the significant contribution analysis upon the counties with monitors that register nonattainment, without regard to the precise boundaries of the nonattainment areas that may ultimately result from the formal designation process under section 107, is the proper approach.

For similar reasons, EPA also disagrees with the commenters' assertion that the provisions of TEA–21 preclude EPA's interpretation of the timing requirements of sections 110(a)(1) and 110(a)(2). However, TEA–21 did address the need to create a new network of monitors to assess the geographic scope and location of $PM_{2.5}$ nonattainment. Also, TEA–21 did provide that such a network should be up and running by December 31, 1999. TEA–21 did lay out a schedule for the collection of data over a period of 3 years in order to make subsequent regulatory decisions. From these facts, the commenters concluded that TEA–21 necessarily contradicts EPA's position that States must now take action to address significant contribution to downwind nonattainment in their

[118] For reasons discussed in more detail above, EPA interprets the requirement of section 110(a)(2)(D) to be among those that Congress intended States to meet within the 3-year timeframe of section 110(a)(1). The EPA agrees that other requirements, such as those of section 110(a)(2)(I), are subject to the different timing requirements of section 172(b).

initial section 110(a)(1) SIPs, merely because the initial 3-year period following the promulgation of a new or revised NAAQS specified in section 110(a)(1) has expired.

The EPA believes that nothing in TEA–21 explicitly or implicitly altered the timing requirements of section 110(a)(1) for compliance with section 110(a)(2)(D), although EPA recognizes that the data from monitoring funded by that Act contributed to the Agency's development of the SIP requirements in today's rulemaking. The provisions of TEA–21 pertained to the installation of a network of monitors for $PM_{2.5}$, and to the timing of designation decisions for $PM_{2.5}$ and 8-hour ozone. To be specific, TEA–21 had two primary purposes for the new NAAQS: (1) To gather information ''for use in the determination of area attainment or nonattainment designations'' for the $PM_{2.5}$ NAAQS; and (2) to ensure that States had adequate time to consider guidance from EPA concerning ''drawing area boundaries prior to submitting area designations'' for the 8-hour ozone NAAQS. TEA–21 sections 6101(b)(1) and (2). The EPA interprets the third stated purpose of TEA–21 to refer to ensuring consistency of timing between the Regional Haze program requirements and the $PM_{2.5}$ NAAQS requirements. With respect to timing, TEA–21 similarly only referred to the dates by which States and EPA should take their respective actions concerning designations. For $PM_{2.5}$, TEA–21 provided that States were required ''to submit designations referred to in section 107(d)(1) * * * within 1 year after receipt of 3 years of air quality monitoring data.'' TEA–21 section 6102(c)(1). For 8-hour ozone, TEA–21 required States to submit designation recommendations within 2 years after the promulgation of the new NAAQS, and required EPA to make final designations within 1 year after that (TEA–21 sections 6103(a) and (b)). In all of these provisions, TEA–21 only addresses SIP timing in the context of the designation process of section 107(d). As explained in more detail above, EPA does not believe that the timing of section 110(a)(1) and section 110(a)(2)(D) obligations depend upon the prior designation of areas in accordance with section 107(d).

The EPA also notes that legislation subsequent to TEA–21 further supports this conclusion. In the 2004 Consolidated Appropriations Act, Congress further amended section 107 to provide specific dates by which States and EPA must make $PM_{2.5}$ designations. 42 U.S.C. 7407 note. The Act now requires States to have made their initial recommendations for $PM_{2.5}$ designations by February 15, 2004, and requires EPA to take action on those recommendations and make its final designation decisions no later than December 31, 2004. Again, these requirements pertain only to formal designations, and do not directly affect the obligations of States to meet other SIP requirements. Neither TEA–21 nor the 2004 Appropriations Act language altered the section 110(a)(1) schedule for compliance with section 110(a)(2)(D).

The commenters suggested that because Congress provided more time for making formal designations pursuant to section 107, it necessarily follows that States should not have to meet the requirements of section 110(a)(2)(D) on the schedule of section 110(a)(1). The EPA believes that Congress did not, through TEA–21 or other actions, alter the existing submission schedule for SIPs to address interstate transport. By contrast, Congress did explicitly alter the schedule for submission of plan revisions to address Regional Haze. From this, EPA infers that Congress did not intend EPA to delay action to address the issue of interstate transport for the 8-hour or $PM_{2.5}$ NAAQS. Thus, EPA must still ensure that States submit SIPs in accordance with the substantive requirements of section 110(a)(2)(D). However, because EPA and the States now have the data and analyses to establish the presence and magnitude of interstate transport, in part through the monitoring data gathered pursuant to TEA–21, the Agency believes that that it is now appropriate to require States to address interstate transport at this time in the manner set forth in today's rule.

c. The EPA's Authority To Require Section 110(a)(2)(D) Submissions Prior to State Submission of Nonattainment Area Plans Under Section 172

Some commenters suggested that EPA cannot determine the existence of a significant contribution from upwind States to downwind States until EPA actually receives the nonattainment area SIPs from each State and evaluates how much ''residual'' nonattainment remains. If the reasoning of these commenters were adopted, downwind States would have to construct SIPs to attain the NAAQS without first knowing what upwind States might ultimately do to reduce interstate transport. Presumably, the theory is that the downwind States may choose to control their own local emissions sources more aggressively so that sources in upwind States could avoid installation of highly cost-effective emission controls, notwithstanding the continued significant impacts of emissions from upwind sources on downwind States. Alternatively, the rationale may be that EPA should wait until submission of upwind State nonattainment area SIPs to discover whether and to what degree the SIPs address interstate transport to downwind States.

For reasons already discussed more fully above, EPA does not believe that the statute requires a ''wait and see'' approach to discover what, if anything, States may ultimately do to address the problem of regional interstate transport. Section 110(a)(1) requires ''each'' State to submit a SIP within 3 years after a new or revised NAAQS addressing the requirements of section 110(a)(2)(D). When the data and the analyses needed to establish the existence of interstate transport of pollutants and to determine whether there is a significant contribution to nonattainment or interference with maintenance by one State in another State are available, as here after the monitoring funded by TEA–21, EPA believes that it may act upon that information prior to State SIP submissions to ensure that States address such contribution expeditiously, as it is doing in this rulemaking. The EPA believes it is a better policy to assist the States to address the regional component of the nonattainment problem in a way that is equitable, timely, cost effective, and certain.

The EPA acknowledges that historically, especially in the case of 1-hour ozone, the Agency has not had the data and the analytical tools to help upwind States to address interstate transport as early in the SIP process as it is doing today for $PM_{2.5}$ and 8-hour ozone. The CAA has required States to regulate ozone or its regulatory predecessors since 1970. For many years, States and EPA focused on the adoption and implementation of local controls to bring local nonattainment areas into attainment. Thus, historically, local areas bore the burden of achieving attainment through imposition of control measures on local sources. By comparison, upwind States did not have to adopt local controls in attainment areas and typically did not adopt such controls solely to lessen the impact of their emissions on downwind States. Since 1977, the CAA has also imposed a series of local control obligations on 1-hour ozone nonattainment areas, such as RACT for stationary sources, inspection and maintenance for mobile sources, and other requirements that became increasingly more stringent, based upon the level of local nonattainment. In spite of these local control efforts, there continued to be a widespread problem with nonattainment that resulted, in part, from unaddressed interstate transport. A lack of information and analytical tools hindered the ability of EPA and the States to address the regional interstate transport component of 1-hour ozone nonattainment, until the NO_X SIP Call in 1998. While it is thus true that the NO_X SIP Call postdated the submission of nonattainment area SIPs, this should not be construed as evidence that the statute precludes the States and EPA from addressing interstate transport earlier in the process for the 8-hour ozone and $PM_{2.5}$ NAAQS.

Given that EPA and the States indisputably have the requisite information to identify interstate transport at this stage of SIP development, EPA believes, based upon its experience in implementing the 1-hour ozone NAAQS, that it is preferable to take action under section 110(a)(2)(D) to address the regional transport component of the $PM_{2.5}$ and 8-hour ozone nonattainment problem. States, both upwind and downwind, will still have an obligation to control emissions from sources within their boundaries for the purposes of local area attainment and maintenance of the NAAQS. The EPA does not believe, however, that it is either required by the statute, or in accordance with sound policy, for the Agency to wait until submission of the nonattainment area SIPs of downwind States to discover whether or not those SIPs will control local sources sufficiently to provide for eventual attainment regardless of continued significant contribution through interstate transport from upwind States. To the contrary, past experience with the 1-hour ozone NAAQS has demonstrated that delayed action to address the interstate component of nonattainment will potentially lead to delays in attainment as downwind areas struggle to overcome the impacts of transport. Indeed, a number of scientific and technical assessments of ozone and $PM_{2.5}$ by the NRC and the Ozone Transport Assessment Group have identified addressing interstate transport as a critical issue in developing SIPs.

d. The EPA's Authority To Require Section 110(a)(2)(D) Submissions Prior to Completion of the Next Review of the $PM_{2.5}$ and 8-Hour Ozone NAAQS

Commenters also asserted that EPA should not take any action to implement the 8-hour ozone and $PM_{2.5}$ NAAQS, until completion of the next NAAQS review cycle. According to the commenters, a series of statements by EPA and others indicated an intention to take no action to implement the NAAQS until after the next review cycle, and that statutes passed by Congress confirm that EPA is to take no such action.

The EPA disagrees with the assertion that it should take no action to implement the 1997 $PM_{2.5}$ and 8-hour ozone NAAQS until completion of the next NAAQS review. Section 110(a) explicitly requires States to begin to submit SIPS within 3 years after promulgation of a new or revised NAAQS. The CAA also requires EPA to take action upon State SIP submissions within specific timeframes. States are likewise explicitly obligated to attain existing NAAQS within certain specified timeframes. None of these basic statutory submission, review, or attainment obligations are stayed or delayed due to the fact that there may be an ongoing NAAQS review cycle. Indeed, under section 109, EPA is to review all NAAQS on an ongoing basis, every 5 years. If the mere existence of a NAAQS review cycle were grounds to suspend implementation of a NAAQS, it would undermine the very goals of the statute.

The commenters argued that certain statements made by EPA and others in guidance memoranda and elsewhere preclude EPA from taking any action to implement the $PM_{2.5}$ and 8-hour ozone NAAQS. The EPA believes that the commenters are misconstruing those statements, and that the statements merely reflect the Agency's assumption that the NAAQS review cycle would occur on the normal schedule. It would be nonsensical to suggest that, if for any reason, the NAAQS review cycle were delayed, that the CAA would permit no implementation of the existing NAAQS. Such an approach would invite and encourage inappropriate interference in the NAAQS review cycle as a means of subverting the CAA.

The commenters further argued that Congress has taken action to prevent implementation of the 8-hour ozone and $PM_{2.5}$ NAAQS pending the next NAAQS review cycle. The EPA does not see any such intention on the part of Congress. In TEA–21 and the 2004 Consolidated Appropriations Act, Congress has amended section 107 to provide specific dates by which States and EPA must make designations. Significantly, Congress did not alter the existing statute with respect to any other deadlines for SIP submissions, or with respect to implementation of the $PM_{2.5}$ and 8-hour ozone NAAQS generally. By contrast, in the 2004 Consolidated Appropriations Act, Congress did explicitly alter the date by which States must submit plan revisions to address Regional Haze. See, Section 7(A), 42 U.S.C. section 7407 note. From this explicit action, one must infer that Congress could have taken action to alter the submission date for plans to address $PM_{2.5}$ or 8-hour ozone, had it intended to alter the existing statutory scheme. Most importantly, however, Congress did not make any of the changes effected in TEA–21 or the 2004 Consolidated Appropriations Act dependent upon completion of the next NAAQS review. To the contrary, Congress directed EPA to take certain actions notwithstanding the fact that there were and are ongoing reviews of the NAAQS. From this, EPA infers that Congress did not intend EPA to defer all action to implement the existing NAAQS, including today's action to assist States to address the requirements of section 110(a)(2)(D).

e. The EPA's Authority To Require States To Make Section 110(a)(2)(D) Submissions Within 18 Months of This Final Rule

Some commenters questioned EPA's proposal to require States to make SIP submissions in response to this action as expeditiously as practicable but no later than within 18 months. A number of commenters suggested that this schedule is too short because of the magnitude or complexity of the task or because of the typical duration of State rulemaking processes. Other commenters suggested that EPA should follow the example of the NO_X SIP Call more closely and provide a shorter period than the Agency proposed.

The EPA has concluded that the proposed 18-month schedule is reasonable given the circumstances and given the scope of the actions that we are requiring States to take. We issued the $PM_{2.5}$ and 8-hour ozone NAAQS revisions in July 1997. More than 3 years have already elapsed since promulgation of the NAAQS, and States have not submitted SIPs to address their section 110(a)(2)(D) obligations under the new NAAQS. We recognize that litigation over the new $PM_{2.5}$ and 8-hour ozone NAAQS created substantial uncertainty as to whether the courts would uphold the new NAAQS, and that this uncertainty, as a practical matter, rendered it more difficult for States to develop SIPs. Moreover, in the case of $PM_{2.5}$, additional time was needed for creation of an adequate monitoring network, collection of at least 3 years of data from that network, and analysis of those data.

In addition, in the NPR, the SNPR, and today's action, we have provided States with a great deal of data and analysis concerning air quality and control costs, as well as policy judgments from EPA concerning the appropriate criteria for determining whether upwind sources contribute significantly to downwind nonattainment under section 110(a)(2)(D). We recognize that States would face great difficulties in developing transport SIPs to meet the requirements of today's action without these data and policies. In light of these factors and the fact that States can no longer meet the original 3-year submittal date of section 110(a)(1), we believe that States need a reasonable period of time in which to comply with the requirements of today's action.

In the comparable NO_X SIP Call rulemaking, EPA provided 12 months for the affected States to submit their SIP revisions. One of the factors that we considered in setting that 12-month period was that upwind States had already, as part of the Ozone Transport Assessment Group process begun 3 years before the NO_X SIP Call rulemaking, been given the opportunity to consider available control options. Because today's action requires affected States to control both SO_2 and NO_X emissions, and to do so for the purpose of addressing both the $PM_{2.5}$ and 8-hour ozone NAAQS, we believe it is reasonable to allow affected States more time than was allotted in the NO_X SIP Call to develop and submit transport SIPs.

Another factor that we have considered is that under section 110(k)(5), the CAA stipulates that EPA may provide up to 18 months for SIP submissions to correct substantially inadequate plans. While today's action is not pursuant to section 110(k)(5), we believe that the provision provides an analogy for the appropriate schedule on which EPA should expect States to make the submission required by today's action. We believe it would not be appropriate to set a longer schedule for submission of the plan than would have been possible under section 110(k)(5) had the States submitted a plan on the original 3-year schedule contemplated in section 110(a)(1) that did not provide for the emissions reductions today's action requires. While the CAA does require States to make some SIP submissions on shorter schedules, we conclude that the complexities of the action required by today's rulemaking militate in favor of a longer schedule.[119]

Finally, we note that by making findings that States have thus far failed to submit SIPs to meet the requirements of section 110(a)(2)(D) for the 8-hour ozone and $PM_{2.5}$ NAAQS, EPA has an obligation to implement a Federal implementation plan (FIP) to address interstate transport no later than 24 months after that finding, if the States fail to take appropriate action. Given this schedule for the FIP obligation, EPA believes that it is reasonable to require States to take action to meet the section 110(a)(2)(D) obligation with respect to the significant contribution identified in today's rule within no more than 18 months. Such a schedule will allow States adequate time to develop submissions to meet this requirement and will afford EPA adequate time to review such submissions before the imposition of a FIP in lieu of a SIP, if necessary.

Thus, EPA has concluded that States should submit SIPs to reduce interstate transport, as required by this final action, as expeditiously as practicable but no later than 18 months from today's date. Such a schedule will provide both upwind and downwind States, and those States that are in both positions relative to other States, to develop SIPs that will facilitate expeditious attainment of the $PM_{2.5}$ and the 8-hour ozone standards.

C. What Happens If a State Fails To Submit a Transport SIP or EPA Disapproves the Submitted SIP?

1. Under What Circumstances Is EPA Required To Promulgate a FIP?

Under section 110(c)(1), EPA is required to promulgate a FIP within 2 years of: (1) finding that a State has failed to make a required submittal; or (2) finding that a submittal received does not satisfy the minimum completeness criteria established under section 110(k)(1)(A) (40 CFR part 51, appendix V); or (3) disapproving a SIP submittal in whole or in part. Section 110(c)(1) mandates that EPA promulgate a FIP unless the States corrects the deficiency and EPA approves the SIP before the time EPA would promulgate the FIP.

2. What Are the Completeness Criteria?

Any SIP submittal that is made with respect to the final CAIR requirements first would be determined to be either incomplete or complete. A finding of completeness is not a determination that the submittal is approvable. Rather, it means the submittal is administratively and technically sufficient for EPA to proceed with its review to determine whether the submittal meets the statutory and regulatory requirements for approval. Under 40 CFR 51.123 and 40 CFR 51.124 (the proposed new regulations for NO_X and SO_2 SIP requirements, respectively), a submittal, to be complete, must meet the criteria described in 40 CFR, part 51, appendix V, ''Criteria for Determining the Completeness of Plan Submissions.'' These criteria apply generally to SIP submissions.

Under CAA section 110(k)(1) and section 1.2 of appendix V, EPA must notify States whether a submittal meets the requirements of appendix V within 60 days of, but no later than 6 months after, EPA's receipt of the submittal. If a completeness determination is not made within 6 months after submission, the submittal is deemed complete by operation of law. For rules submitted in response to the CAIR, EPA intends to make completeness determinations expeditiously.

3. When Would EPA Promulgate the CAIR Transport FIP?

The EPA views seriously its responsibility to address the issue of regional transport of $PM_{2.5}$, ozone, and precursor emissions. Decreases in NO_X and SO_2 emissions are needed in the States named in the CAIR to enable the downwind States to develop and implement plans to achieve the $PM_{2.5}$ and 8-hour ozone NAAQS and provide clean air for their residents. Thus, EPA intends to promulgate the FIP shortly after the CAIR SIP submission deadline for States that fail to submit approvable SIPs in order to help assure that the downwind States realize the air quality benefits of regional NO_X and SO_2 reductions as soon as practicable. This is consistent with Congress' intent that attainment occur in these downwind nonattainment areas ''as expeditiously as practicable'' (sections 181(a), 172(a)). To this end, EPA intends to propose the FIP prior to the SIP submission deadline.

The FIP proposal would achieve the NO_X and SO_2 emissions reductions required under the CAIR by requiring EGUs in affected States to reduce emissions through participation in Federal NO_X and SO_2 cap and trade programs. The EPA intends to integrate these Federal trading programs with the model trading programs that States may choose to adopt to meet the CAIR. Although EPA would be proposing FIPs for all States affected by the CAIR, EPA will only issue a final FIP for those jurisdictions that fail to respond adequately to the CAIR.

[119] See, *e.g.,* section 182(a)(2)(A) (providing a 6-month schedule for submission of a revision to provide for RACT corrections); section 189(d) (providing 12 months for submission of plan revisions to ensure attainment and required emissions reductions). The former revision could be relatively limited in scope, but the latter might entail submission of a completely revised SIP.

The EPA's goal is to have approvable SIPs that meet the requirements of the CAIR. We remain ready to work with the States to develop fully approvable SIPs, which would eliminate the need for EPA to promulgate a FIP.

D. What Are the Emissions Reporting Requirements for States?

The EPA believes that it is essential that achievement of the emissions reductions required by the CAIR be verified on a regular basis. Emission reporting is the principal mechanism to verify these reductions and to assure the downwind affected States and EPA that the ozone and $PM_{2.5}$ transport problems are being mitigated as required by the rule. Therefore, the final rule establishes a small set of new emission reporting requirements applicable to States affected by the CAIR, covering certain emissions data not already required under existing emission reporting regulations. The rule language also removes a current emission reporting requirement related to the NO_X SIP call, which we believe is not necessary, for reasons explained below. A number of other proposed changes in emission reporting requirements which would have affected States not subject to the final CAIR are not included in the final rule, for reasons explained below. We will repropose these other changes, with modifications, in a separate proposal to allow additional opportunity for public comment.

1. Purpose and Authority

Because we are consolidating and harmonizing the new emission reporting requirements promulgated today with two pre-existing sets of emission reporting requirements, we review here the purpose and authority for emission reporting requirements in general.

Emissions inventories are critical for the efforts of State, local, and Federal agencies to attain and maintain the NAAQS that EPA has established for criteria pollutants such as ozone, PM, and CO. Pursuant to its authority under sections 110 and 172 of the CAA, EPA has long required SIPs to provide for the submission by States to EPA of emissions inventories containing information regarding the emissions of criteria pollutants and their precursors (*e.g.*, VOCs). The EPA codified these requirements in subpart Q of 40 CFR part 51, in 1979 and amended them in 1987.

The 1990 Amendments to the CAA revised many of the provisions of the CAA related to the attainment of the NAAQS and the protection of visibility in Class I areas. These revisions established new periodic emissions inventory requirements applicable to certain areas that were designated nonattainment for certain pollutants. For example, section 182(a)(3)(A) required States to submit an emissions inventory every 3 years for ozone nonattainment areas beginning in 1993. Similarly, section 187(a)(5) required States to submit an inventory every 3 years for CO nonattainment areas. The EPA, however, did not immediately codify these statutory requirements in the CFR, but simply relied on the statutory language to implement them.

In 1998, EPA promulgated the NO_X SIP call which requires the affected States and the District of Columbia to submit SIP revisions providing for NO_X reductions to reduce their adverse impact on downwind ozone nonattainment areas. (63 FR 57356, October 27, 1998). As part of that rule, codified in 40 CFR 51.122, EPA established emissions reporting requirements to be included in the SIP revisions required under that action.

Another set of emissions reporting requirements, termed the Consolidated Emissions Reporting Rule (CERR), was promulgated by EPA in 2002, and is codified at 40 CFR part 51 subpart A. (67 FR 39602, June 10, 2002). These requirements replaced the requirements previously contained in subpart Q, expanding their geographic and pollutant coverages while simplifying them in other ways.

The principal statutory authority for the emissions inventory reporting requirements outlined in this final rule is found in CAA section 110(a)(2)(F), which provides that SIPs must require "as may be prescribed by the Administrator * * * (ii) periodic reports on the nature and amounts of emissions and emissions-related data from such sources." Section 301(a) of the CAA provides authority for EPA to promulgate regulations under this provision.[120]

2. Pre-existing Emission Reporting Requirements

As noted above, prior to this final rule, two sections of title 40 of the CFR contained emissions reporting requirements that are applicable to States: Subpart A of part 51 (the CERR) and section 51.122 in subpart G of part 51 (the NO_X SIP Call reporting requirements).

Under the NO_X SIP Call requirements in section 51.122, emissions of NO_X for a defined 5-month ozone season (May 1 through September 30) and for work weekday emissions for point, area and mobile sources that the State has subjected to emissions control to comply with the requirements of the NO_X SIP Call, are required to be reported by the affected States to EPA every year. However, emissions of sources reporting directly to EPA as part of the NO_X trading program are not required to be reported by the State to EPA every year. The affected States are also required to report ozone season emissions and typical summer daily emissions of NO_X from all sources every third year (2002, 2005, etc.) and in 2007. This triennial reporting process does not have an exemption for sources participating in the emissions trading programs. Section 51.122 also requires that a number of data elements be reported for each source in addition to ozone season NO_X emissions. These data elements describe certain of the source's physical and operational parameters.

Emissions reporting under the NO_X SIP Call as first promulgated was required starting for the emissions reporting year 2002, the year prior to the start of the required emissions reductions. The reports are due to EPA on December 31 of the calendar year following the inventory year. For example, emissions from all sources and types in the 2002 ozone season were required to be reported on December 31, 2003. However, because the Court which heard challenges to the NO_X SIP Call delayed the implementation by 1 year to 2004, no State was required to start reporting until the 2003 inventory year. The EPA promulgated a rule to subject Georgia and Missouri to the NO_X SIP Call with an implementation date of 2007. (*See* 69 FR 21604, April 21, 2004.) We have recently proposed to stay the NO_X SIP Call for Georgia (*see* 70 FR 9897, March 1, 2005). Missouri's emissions reporting begins with 2006. These emissions reporting requirements under the NO_X SIP Call affect the District of Columbia and 18 of the 28 States affected by the proposed CAIR.

As noted above, the other set of pre-existing emissions reporting requirements is codified at subpart A of part 51. Although entitled the Consolidated Emissions Reporting Rule (CERR), this rule left in place the separate § 51.122 for the NO_X SIP Call reporting. The CERR requirements were aimed at obtaining emissions information to support a broader set of purposes under the CAA than were the reporting requirements under the NO_X

[120] Other CAA provisions relevant to this final rule include section 172(c)(3) (provides that SIPs for nonattainment areas must include comprehensive, current inventory of actual emissions, including periodic revisions); section 182(a)(3)(A) (emissions inventories from ozone nonattainment areas); and section 187(a)(5) (emissions inventories from CO nonattainment areas).

SIP Call. The CERR requirements apply to all States.

Like the requirements under the NO_X SIP Call, the CERR requires reporting of all sources at 3-year intervals (2005, 2008, etc.). It requires reporting of certain large sources every year. However, the required reporting date under the CERR is 5 months later than under the NO_X SIP Call reporting requirements. Also, emissions must be reported for the whole year, for a typical day in winter, and a typical day in summer, but not for the 5-month ozone season as is required by the NO_X SIP Call. Finally, the CERR and the NO_X SIP Call differ in what non-emissions data elements must be reported.

3. Summary of the Proposed Emissions Reporting Requirements

On June 10, 2004, EPA published a SNPR (69 FR 32684) to EPA's January 30, 2004 proposal (69 FR 4566). The EPA's main objective with respect to emissions reporting was to add limited new requirements for emissions reports to serve the additional purposes of verifying the CAIR-required emissions reductions. The SNPR also sought to harmonize the CERR and NO_X SIP Call reporting requirements with respect to specific data elements and consolidate them entirely in subpart A, and to reduce and simplify the reporting requirements in several ways. These latter changes were proposed to be applicable to all States, not just those affected by the CAIR emissions reduction requirements. The major changes included in the SNPR are described below.

Amendments were proposed to subpart A, which contains § 51.1 through 51.45 and an appendix, and to § 51.122. We also proposed to add a new § 51.125.

- In § 51.122, the NO_X SIP Call provisions, we proposed to abolish certain requirements entirely, and to replace certain requirements with a cross reference to subpart A so that detailed lists of required data elements appeared only in subpart A. As proposed, § 51.122 would then have specified what pollutants, sources, and time periods the States subject to the NO_X SIP Call must report and when, but would no longer have listed the detailed data elements required for those reports.
- The proposed new § 51.125 would have been functionally parallel to § 51.122, specifying all the pollutants, sources, and time periods the States subject to the proposed CAIR must report and when, referencing subpart A for the detailed data elements required.
- The proposed amended subpart A would have listed the detailed data elements for all three reporting programs (CERR, NO_X SIP Call, and CAIR) as well as provided information on submittal procedures, definitions, and other generally applicable provisions.

Taken together, the pre-existing emissions reporting requirements under the NO_X SIP Call and CERR were already rather comprehensive in terms of the States covered and the information required. Therefore, the practical impact of the proposed changes would have imposed only three new requirements.

First, in Arkansas, Florida, Iowa, Louisiana, Mississippi, and Wisconsin for which we proposed and are finalizing a finding of significant contribution to ozone nonattainment in another State but which were not among the 22 States already subject to the NO_X SIP Call, the required emissions reporting would be expanded to match those of the 22 States. The proposed change would require that they report NO_X emissions during the 5-month ozone season and for a typical summer day, in addition to the existing requirement for reporting emissions for the full year. We proposed that this new requirement begin with the triennial inventory year prior to the CAIR implementation date. This would be the 2008 inventory year, the report for which would be due to EPA by June 1, 2010.

Second, under the existing CERR, yearly reporting is required only for sources whose emissions exceed specified amounts. The SNPR proposed that the 28 States and the District of Columbia subject to the CAIR for reasons of $PM_{2.5}$ must report to EPA each year a set of specified data elements for all sources subject to new controls adopted specifically to meet the CAIR requirements related to $PM_{2.5}$, unless the sources participate in an EPA-administered emissions trading program. We proposed that this new requirement begin with the 2009 inventory year, the report for which will be due to EPA by June 1, 2011. This new requirement would have no effect on States that fully comply with the CAIR by requiring their EGUs to participate in the CAIR model cap and trade programs.

Third, in all States, we proposed to expand the definition of what sources must report in point source format, so that fewer sources would be included in non-point source emissions.[121] We proposed to base the requirement for point source format reporting on whether the source is a major source under 40 CFR part 70 for the pollutants for which reporting is required, *i.e.,* for CO, VOC, NO_X, SO_2, $PM_{2.5}$, PM_{10} and ammonia but without regard to emissions of hazardous air pollutants.

A number of other proposed changes would have reduced reporting requirements on States or provided them with additional options. Two of the proposed changes in this category are of special note in understanding the final requirements of today's rule. (The remainder of these changes were explained in the SNPR at 69 FR 32697.)

- The NO_X SIP Call rule requires the affected States to submit emissions inventory reports for a given ozone season to EPA by December 31 of the following year. The CERR requires similar but not identical reports from all States by the following June 1, five months later. We proposed to move the December 31 reporting requirement to the following June 1, the more generally applicable submission date affecting all 50 States. We asked for comment on whether allowing this 5-month delay is consistent with the air quality goals served by the emissions reporting requirements. However, we also asked for comment on the alternative of moving forward to December 31 all or part of the June 1 reporting for all 50 States. In particular, we solicited comment on requiring that point sources be reported on December 31 and other sources on June 1.
- We also proposed to eliminate a requirement of the NO_X SIP Call for a special all-sources report by affected States for the year 2007, due December 31, 2008.

4. Summary of Comments Received and EPA's Responses

A number of commenters objected to the 45-day comment period as being too short to allow for full understanding of and comment on the emissions reporting changes that EPA had proposed. With respect to this issue, EPA believes that the comment period was sufficient for those proposed changes that would affect the States subject to the emissions reductions

[121] We used the term "non-point source" in the SNPR to refer to a stationary source that is treated for inventory purposes as part of an aggregated source category rather than as an individual facility. In the existing subpart A of part 51, such emissions sources are referred to as "area sources." However, the term "area source" is used in section 112 of the CAA to indicate a non-major source of hazardous air pollutants, which could be a point source. As emissions inventory activities increasingly encompass both NAAQS-related pollutants and hazardous air pollutants, the differing uses of "area source" can cause confusion. Accordingly, EPA proposed to substitute the term "non-point source" for the term "area source" in subpart A, § 51.122, and the new § 51.125 to avoid confusion. We are not finalizing this change in terminology in today's rule.

requirements of the CAIR and that are specifically directed at ensuring the effectiveness of the CAIR, namely: (1) The requirement for six more States to report ozone season emissions, and (2) the requirement for all subject States to report annual emissions from controlled sources every year if those sources are not participating in the emission trading programs. These proposed changes are easy to understand on their face, and also have close precedents in the NO_X SIP Call. Moreover, the States affected by these proposed reporting requirements were identified as being subject to the proposed emissions reduction requirements of the CAIR in the original NPR, and thus they knew to be alert to the contents of the SNPR. We also consider the comment period sufficient with respect to two other specific elements of the proposal, namely (3) the proposal to eliminate the 2007 inventory reporting requirement under the NO_X SIP Call and (4) the proposal to change the reporting date for the NO_X SIP Call from December 31 (12 months after the end of the reported year) to June 1 (17 months after the end of the reported year). These were also readily understood proposals, and the States affected by them were among those initially identified as subject to the CAIR itself. A number of substantive comments were received on these four proposed changes. Therefore, we have concluded that it is appropriate to consider the substantive comments that were received on these four elements of the SNPR, and to take final action on them. The disposition of the remaining elements of the SNPR is discussed further below.

The EPA received one comment from the Mississippi Department of Environmental Quality on the proposed requirement that Mississippi and five other States report ozone season emissions. Mississippi disagreed that they should be included with the other States subject to the CAIR provisions, including the emissions reporting provisions. The EPA has concluded that the analysis performed to support CAIR and discussed earlier in this preamble amply demonstrates that Mississippi should be included in the CAIR and subject to the CAIR emissions reporting requirements.

We did not receive comments specifically on the proposal to require States to report annual emissions every year from sources controlled to comply with the CAIR, if those sources are not participating in the emission trading programs operated by EPA. While we expect the number of such sources to be small if not zero, we continue to believe that tracking their emissions from year to year is appropriate, and we are finalizing this requirement. Since the CERR already contains a requirement for every-year reporting of emissions from point sources above certain emission thresholds, this requirement will have an incremental impact only if States choose to control fairly small point sources or nonpoint or mobile sources as part of their plan for meeting the CAIR requirements.

The EPA received several comments regarding the elimination of the NO_X SIP Call special all-sources 2007 emissions inventory. These comments all favored the elimination of the 2007 emissions inventory, which EPA is promulgating in today's rule. We would like to clarify that the NO_X SIP Call contained no requirement that any State make a retrospective demonstration that actual statewide emissions of NO_X were within any limit. The requirement for the 2007 inventory was for the purpose of program evaluation by EPA. As explained in the SNPR, we believe that in light of the data on 2007 emissions that will be available from the NO_X trading program and the further reductions in NO_X required by the CAIR, the 2007 inventory submissions from the States are not needed for this purpose.

The EPA also proposed to harmonize the report due dates for the NO_X SIP Call, currently 12 months after the end of the reported year, and for the CERR, currently 17 months after the end of the reported year. The EPA proposed to harmonize the dates for both at 17 months, but asked for comments on a 12-month due date. Several comments were received, all favoring harmonizing the report due date at 17 months. While we continue to believe in the efficiency advantage of harmonized submission date requirements, we are not finalizing this change. The EPA has reconsidered this part of the proposed emissions reporting requirements and believes that it may be in the interest of the public to move in the direction of shortening the emissions reporting cycle for all three reporting requirements (CERR, NO_X SIP Call, and CAIR), rather than accepting the longer CERR cycle for all three reporting requirements. In today's final rule, we are retaining the 12-month submission date requirement of the original NO_X SIP Call for the States already subject to it. For the six States that are newly subject to reporting ozone season NO_X emissions and for the new requirement for every-year reporting by sources controlled to meet the CAIR requirements for SO_2 and NO_X annual emissions reductions but not included in the trading programs, the required reporting date for States will be June 1, 17 months after the end of the reported year, as was proposed. We will address reporting deadlines comprehensively in a separate NPR which will propose a unified, but shorter period of time to report to EPA. This separate notice will allow for more public comment on the reporting cycle. The dual approach to reporting due dates retained in today's rule will be combined into unified due dates and will be influenced by comments received in response to our proposal when the separate rulemaking is completed.

Regarding elements of the proposed requirements beyond these four, i.e., the requirements that would have affected States not subjected to the CAIR emissions reduction requirements as well as CAIR States, many commenters said that EPA should not have included changes to national emissions reporting requirements in a proposed rule placing emissions reduction requirements on only certain States. Commenters also questioned whether EPA had given adequate time for comment on the more detailed revisions in required data elements, definitions, etc. Substantively, many commenters supported some or all of the proposed changes, but some commenters objected to some of them.

The EPA has considered these comments. Without conceding EPA's legal authority to include these provisions in the final rule in light of the history of proposal, public hearing, and comment period, EPA has—in an abundance of caution—decided to omit these provisions from today's rule (see section VIII.D.5 Summary of the Emissions Reporting Requirements below for the changes which are being finalized today). We will repropose them, with modifications, in a separate NPR to allow additional opportunity for public comment by all affected States and other parties.

5. Summary of the Emissions Reporting Requirements

As a result of the comments received, EPA has revised the emissions reporting requirements of today's rule by limiting new requirements to the ones where sufficient notice and opportunity for comment was clearly given in the June 10, 2004, SNPR and that either: (1) Are necessary for the monitoring of the implementation of the emissions reduction requirements of the CAIR, or (2) are changes in reporting under the NO_X SIP Call linked to the CAIR. Three specific emissions reporting provisions that change the pre-existing requirements are included in today's rule.

1. Alabama, Arkansas, Connecticut, Delaware, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin and the District of Columbia, which are subject to the CAIR for reasons of ozone, are made subject to emission reporting requirements for NO_X that are very similar to the existing requirements of the NO_X SIP Call, which already affects all but six of these States. For these six States (Arkansas, Florida, Iowa, Louisiana, Mississippi and Wisconsin) a new requirement is that they report NO_X emissions during the 5-month ozone season from all sources every three years, in addition to reporting emissions for the full year and for a summer day as was already required. This new requirement begins with the triennial inventory year 2008. For all the listed States, a new requirement is to report to EPA for 2009 and each year thereafter the ozone-season and summer day NO_X emissions, plus a set of specified other data elements, for all sources subject to new controls adopted specifically to meet the CAIR requirements related to ozone, unless the sources participate in an EPA-administered emissions trading program. These reports will be due June 1 of the second year following the end of the reported year, *i.e.*, 17 months after the end of the reported year. The existing CERR includes several other reporting requirements which in conjunction with this new requirement will meet the needs for monitoring the implementation of required NO_X emissions reductions.

2. Alabama, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin and the District of Columbia, which are subject to the CAIR for reasons of $PM_{2.5}$, must report to EPA each year annual NO_X and SO_2 emissions, plus a set of specified other data elements, for all sources subject to new controls adopted specifically to meet the CAIR requirements related to $PM_{2.5}$, unless the sources participate in an EPA-administered emissions trading program. Previously, these states may have been required to report these sources only every third year, depending on their size. The existing CERR includes several other reporting requirements which in conjunction with this new requirement will meet the needs for monitoring the implementation of required NO_X and SO_2 emissions reductions.

3. The EPA has determined that the requirement in the NO_X SIP Call for a special all-sources report by affected States for the year 2007, due December 31, 2008, is no longer needed to administer provisions in the NO_X SIP Call. Accordingly, EPA is eliminating this requirement in today's rule.

The final rule accomplishes these changes by making minimal changes to the existing provisions of 40 CFR part 51. Subpart A, which contains the CERR requirements, is not amended at all. 40 CFR 51.122, the section containing emission inventory reporting requirements for the NO_X SIP Call, is substantively amended only to delete the requirement for the 2007 inventory report.[122] A new section 40 CFR 51.125 is added to contain the two new emission inventory reporting requirements specifically related to the new CAIR requirements for emissions reductions, regarding ozone-season emissions of NO_X and every-year reporting of NO_X and SO_2 emissions from all sources controlled but not participating in the EPA trading programs. The new 40 CFR 51.125 refers to 40 CFR subpart A for the other specific data elements that must be reported.

VIII. Model NO_X and SO_2 Cap and Trade Programs

A. What Is the Overall Structure of the Model NO_X and SO_2 Cap and Trade Programs?

The EPA is finalizing model rules for the CAIR annual NO_X, CAIR ozone-season NO_X, and SO_2 trading programs that States can use to meet the emission reduction requirements in the CAIR. These rules are designed to be referenced by States in State rulemaking. State use of the model cap and trade rules helps to ensure consistency between the State programs, which is necessary for the market aspects of the regional trading program to function properly. It also allows the CAIR Program to build on the successful Acid Rain Program. Consistency in the CAIR requirements from State-to-State benefits the affected sources, as well as EPA, which administers the program on behalf of States.

This section focuses on the structure which maintains the existing NO_X SIP Call rules (in part 96, subparts A through J) while adding parallel rules for the CAIR annual NO_X (in subparts AA through II), CAIR SO_2 (in subparts AAA through III), and the CAIR ozone-season NO_X (in subparts AAAA through IIII) of the model rules. Commenters generally supported the proposed structure of the model rules, as well as the use of the cap and trade approach, which are maintained in the final rules. Later sections of today's rule discuss specific aspects of the model rules that have been modified or maintained in response to comment.

The EPA designed the model rules to parallel the NO_X SIP Call model trading rules (part 96) and to coordinate with the Acid Rain Program. Mirroring the structure of existing part 96 in the final CAIR NO_X and SO_2 model rules will ease the transition to the CAIR rules as many States and sources are already familiar with the layout of the NO_X SIP Call rule. In addition, because the EPA proposed new CAIR model trading rules—separate from the existing NO_X SIP Call model rule in part 96—States can continue to reference part 96 (subparts A through J) through 2008. The CAIR ozone-season NO_X cap and trade program that the EPA has included in today's final rule is intended for use by CAIR ozone-affected sources as well as those subject to the NO_X SIP Call in 2009 and beyond. Those States that wish to use an EPA-administered, ozone-season cap and trade program to achieve the reductions mandated by the CAIR or the NO_X SIP Call, must use the CAIR ozone-season NO_X model rule (subparts AAAA through IIII) in 2009 and beyond.

The model rules rely on the detailed unit-level emissions monitoring and reporting procedures of part 75 and consistent allowance management practices. (Note that full CAIR-related SIP requirements, *i.e.*, part 51, are discussed in section VII of today's preamble.) Additionally, section IX.B of today's preamble discusses the final revisions to parts 72 through 77 in order to, among other things, facilitate the interaction of the title IV Acid Rain Program's SO_2 cap and trade provisions and those of the CAIR SO_2 trading program.

Road Map of Model Cap and Trade Rules

The following is a brief ''road map'' to the final CAIR NO_X and SO_2 cap and trade programs. Please refer to the detailed discussions of the CAIR

[122] 40 CFR 51.122 is also amended: (1) to remove a reference to now-obsolete electronic data reporting processes (a ''housekeeping'' deletion that was specifically included in the proposed rule text with the SNPR), and (2) to make a minor technical correction to properly indicate which of the latitude versus longitude data elements corresponds to the x-coordinate and which to the y-coordinate (a correction that was implicitly proposed in the SNPR in that 51.122 was proposed to refer to 51 subpart A for all its data element descriptions).

programmatic elements throughout today's rule for further information on each aspect.

State Participation

• States have flexibility to achieve emissions reductions however they chose, including developing and implementing their own trading program.

• States may elect to participate in an EPA-managed cap and trade program. To participate, a State must adopt the model cap and trade rules finalized in this section of today's rule with flexibility to modify sections regarding NO_X allocations and whether to include individual unit opt-in provisions.

• States may participate in EPA-managed cap and trade programs for either the annual NO_X, the ozone-season NO_X, the SO_2, or any combination. The State can only choose to participate in the EPA-administered, CAIR cap and trade program(s) that is (are) relevant to their finding(s).

• The annual NO_X model rule is to be used by only those States that are affected by the CAIR $PM_{2.5}$ finding.

• The ozone-season NO_X model rule is designed to be used by those States that are affected by the CAIR ozone finding as well as take the place of the NO_X SIP Call requirements.[123] The CAIR ozone-season NO_X program will be the only ozone-season NO_X program that EPA will administer. Because EPA will no longer run a NO_X SIP Call trading program, States may include their NO_X SIP Call trading sources if they adopt the EPA-administered CAIR ozone-season NO_X program.

• The SO_2 model rule is designed to satisfy the ongoing statutory requirements of the title IV Acid Rain SO_2 cap and trade program—with sequential compliance with title IV and the CAIR—for sources in the CAIR region that are affected by both the Acid Rain Program and the CAIR.

Trading Sources

• States must achieve all of the mandated emission reductions from EGUs to participate in EPA-managed cap and trade programs. States may include other NO_X SIP Call trading sources in the ozone-season CAIR NO_X cap and trade program and still participate in EPA-managed cap and trade programs.

• States may participate in EPA-managed cap and trade programs whether or not they adopt the optional individual opt-in provisions of the model rule. However, if the State chooses to allow individual sources to opt-in, the opt-in requirements must reflect the requirements of the model rule.

Emission Allowances

• The CAIR annual NO_X cap and trade program will rely upon CAIR annual NO_X allowances allocated by the States. The NO_X SIP Call allowances and CAIR ozone-season NO_X allowances cannot be used for compliance with the annual CAIR reduction requirement. (Note that allowances from the Compliance Supplement Pool (CSP) will be CAIR annual NO_X allowances.)

• The CAIR ozone-season NO_X cap and trade program will rely upon CAIR ozone-season NO_X allowances allocated by the States. In addition, pre-2009 NO_X SIP Call allowances can be banked into the program and used by CAIR-affected sources for compliance with the CAIR ozone-season NO_X program. The NO_X SIP Call allowances of vintages 2009 and later can not be used for compliance with any EPA-administered cap and trade programs.

• The CAIR SO_2 cap and trade program will rely upon title IV SO_2 allowances but may also include additional CAIR SO_2 allowances, should a State that allows an individual unit opt-in mechanism provide CAIR SO_2 allowwances to an opt-in source. Pre-2010 title IV SO_2 allowances can be used for compliance with the CAIR.

• Sulfur dioxide reductions are achieved by requiring sources to retire more than one allowance for each ton of SO_2 emissions. The emission value of an SO_2 allowance is independent of the year in which it is used, but is based upon its vintage (*i.e.*, the year in which the allowance is issued). Sulfur dioxide allowances of vintage 2009 and earlier offset one ton of SO_2 emissions. Vintages 2010 through 2014 offset 0.5 tons of emissions. And, vintages 2015 and beyond offset 0.35 tons of emissions.

Allocation of Allowances to Sources

• For SO_2 allowances, sources have already received allowances through title IV.

• NO_X allowances (for both the annual and ozone-season programs) will be allocated based upon the State's chosen allocation methodology. The EPA's model NO_X rules have provided an example allocation, complete with regulatory text, that may be used by State's or replaced by text that implements a States alternative allocation methodology.

Compliance Supplement Pool (CSP)

• Each State will have a share of the CSP that is comprised of 200,000[124] CAIR annual NO_X allowances of vintage year 2009. The State may distribute the CSP allowances based upon the criteria, found in the SIP Approvability section of today's rule, for early reductions and need.

Emission Monitoring and Reporting by Sources

• Sources monitor and report their emissions using part 75. This includes individual sources that opt-in to the program.

• Source information management, emissions data reporting, and allowance trading is done through on-line systems similar to those currently used for the Acid Rain SO_2 and NO_X SIP Call Programs.

• Emission monitoring and reporting for both the CAIR annual and ozone-season NO_X cap and trade programs will use part 75.

Compliance and Penalties

• Compliance for the annual and ozone-season NO_X cap and trade programs, as well as the SO_2 program, will be determined separately.[125]

• For the NO_X and SO_2 cap and trade programs, any source found to have excess emissions must: (1) Surrender allowances sufficient to offset the excess emissions; and, (2) surrender allowances from the next control period equal to three times the excess emissions.

Comments Regarding the Use of a Cap and Trade Approach and the Proposed Structure

Commenters overwhelmingly supported the use of a cap and trade approach and the overall framework of the model rules to achieve the mandated emissions reductions. Some supported the use of cap and trade for achieving regional emissions reductions but noted the need to have additional measures that ensure that emission reductions take place in nonattainment areas. This is in line with the EPA's strategy of reducing transported SO_2 and NO_X through a regionwide cap and trade approach and encouraging States to take complementary measures to address their particular, persistent nonattainment issues. (Note that comments on specific mechanisms

[123] Rhode Island (RI) is the only State currently participating in the NO_X SIP Call cap and trade program that is not affected by today's ozone finding. As is explained in section IX, RI may join the CAIR ozone-season trading program as a means of satisfying its NO_X SIP Call requirements.

[124] The 200,000 total includes the share of the CSP that DE and NJ would receive if the EPA finalizes a parallel rule finding that they are significant contributors for $PM_{2.5}$.

[125] Compliance with the title IV Acid Rain Program will be determined separately from CAIR compliance.

within the cap and trade program are discussed in the topic-specific sections that follow.)

B. What Is the Process for States To Adopt the Model Cap and Trade Programs and How Will It Interact With Existing Programs?

1. Adopting the Model Cap and Trade Programs

States may choose to participate in the EPA-administered cap and trade programs, which are a fully approvable control strategy for achieving all of the emissions reductions required under today's rulemaking in a highly cost-effective manner. States may simply reference the model rules in their State rules and, thereby, comply with the requirements for statewide budget demonstrations detailed in section VII.B of today's preamble. Affected States for both $PM_{2.5}$ and ozone can adopt the annual NO_X and SO_2 cap and trade programs in part 96, subparts AA through II, part 96 subparts AAA through III, and AAAA through IIII. States with ozone-season only CAIR requirements (*i.e.*, Arkansas, Connecticut, Delaware, Massachusetts, and New Jersey) can adopt the ozone-season CAIR NO_X program (subparts AAAA through IIII). Part 96 subparts AA through II and AAA through III can be used by States that are affected for only $PM_{2.5}$ (*i.e.*, Georgia, Minnesota, and Texas). States that elect to achieve the required reductions by regulating other sources or using other approaches will follow alternate State requirements, also described in section VII.B of today's preamble.

As proposed, EPA is requiring States that wish to participate in the EPA-managed cap and trade program to use the model rule to ensure that all participating sources, regardless of which State in the CAIR region they are located, are subject to the same trading and allowance holding requirements. Further, requiring States to use the complete model rule provides for accurate, certain, and consistent quantification of emissions. Because emissions quantification is the basis for applying the emissions authorization provided by each allowance and emissions authorizations (in the form of allowances) are the valuable commodity traded in the market, the emissions quantification requirements of the model rule are necessary to maintain the integrity of the cap and trade approach of the program and therefore, to ensure that the environmental goals of the program are met.

For States Electing To Participate in the EPA-Administered Ozone-Season CAIR NO_X Cap and Trade Program

States that wish to achieve their CAIR ozone-season requirements through an EPA-administered ozone-season NO_X cap and trade program will adopt the CAIR model rule in subparts AAAA through IIII. (Note that the EPA-administered annual NO_X CAIR cap and trade program is independent of ozone-season CAIR NO_X model rule.) Because EPA will no longer administer the trading program for the NO_X SIP Call, States that wish to continue to meet their NO_X SIP Call obligations through an EPA-administered cap and trade program will also adopt the CAIR ozone-season model rule. NO_X SIP Call States will ''sun set'' their NO_X SIP Call rules for sources that will move into the CAIR NO_X ozone-season program. Part 96, sections A–J (*i.e.*, the NO_X SIP Call trading rule) will continue to be available for the NO_X SIP Call and will not be removed for the CAIR. The CAIR model rules specifically address how NO_X SIP Call allowances carry forward into the CAIR NO_X ozone-season program. (Section IX.A provides additional discussion of interactions between the CAIR and the NO_X SIP Call).

For States Electing To Participate in the EPA-Administered Annual NO_X Cap and Trade Program

States that are $PM_{2.5}$ affected and wish to participate in an EPA-administered annual NO_X cap and trade program will adopt the CAIR model rule in subparts AA through II. States may participate by either adopting the model rule provisions by reference or codifying the model rule in their State regulations.

For States Electing To Participate in the EPA-Administered SO_2 Cap and Trade Program

States may simply adopt new provisions, whether by incorporating by reference the CAIR SO_2 cap and Trade rule (part 96, subparts AAA through III) or codifying the provisions of the CAIR SO_2 cap and trade rules, in order to participate in the EPA-administered SO_2 cap and trade program. The CAIR SO_2 model rule works in conjunction with the Acid Rain Program provisions, which are implemented at the Federal level and will stay in place. Today's action also finalizes some revisions to the Acid Rain Program (*i.e.*, parts 72, 73, 74, 75, and 78). (Section IX.B of today's preamble provides additional discussion of interactions between the CAIR and the Acid Rain Program and changes to the Acid Rain Program).

Comments Regarding the Process for Adopting the Model Rules

Commenters supported EPA's proposed process and emphasized the importance of workable model rules, because States with limited resources are likely to incorporate them by reference or heavily rely on them as the basis for State rules.

2. Flexibility in Adopting Model Cap and Trade Rules

It is important to have consistency on a State-to-State basis with the basic requirements of the cap and trade approach when implementing a multi-State cap and trade program. Such consistency ensures the: Preservation of the integrity of the cap and trade approach so that the required emissions reductions are achieved; smooth and efficient operation of the trading market and infrastructure across the multi-State CAIR region so that compliance and administrative costs are minimized; and equitable treatment of owners and operators of regulated sources. However, EPA believes that some limited differences are possible without jeopardizing the environmental and other goals of the program. Therefore, the final rule allows States to modify the model rule language to best suit their unique circumstances in a few, specific areas.

First, States have the flexibility to include, as full trading partners, all trading sources affected by the NO_X SIP Call in the ozone-season CAIR NO_X cap and trade program. This is an outgrowth of the development of the CAIR ozone-season NO_X program, which will be the only ozone-season NO_X cap and trade program administered by EPA.

In addition, States may develop their own NO_X allocations methodologies, provided allocation information is submitted to EPA in the required timeframe. (Section VIII.D of today's preamble discusses unit-level allocations and the related comments in greater detail. This includes a discussion of the provisions establishing the advance notice States must provide for unit-by-unit allocations).

Lastly, States using the model cap and trade rules may elect to include provisions that allow individual units to ''opt-in'' to the cap and trade programs. States that wish to include this mechanism must adopt provisions discussed in section VIII.G of today's rulemaking. Adopting the individual unit opt-in provisions, which would allow non-EGUs that meet the opt-in requirements to enter into the EPA-managed cap and trade programs, does not preclude a State from participating in the EPA-administered cap and trade programs.

C. What Sources Are Affected Under the Model Cap and Trade Rules?

In the January 2004 NPR, EPA proposed a method for developing budgets that assumed reductions only from EGUs. Electric Generating Units were defined as: Fossil fuel-fired, non-cogeneration EGUs serving a generator with a nameplate capacity of greater than 25 MWe; and fossil fuel-fired cogeneration EGUs meeting certain criteria (referred to as the ''⅓ potential electric output capacity criteria''). In the SNPR, we proposed model cap and trade rules that applied to the same categories of sources. We are finalizing the nameplate capacity cut-off that we proposed in the NPR for developing budgets and that we proposed in the SNPR for the applicability of the model trading rules. We are also finalizing the ''fossil fuel-fired'' definition and the ⅓ electric output capacity criteria that were proposed. The actual rule language in the SNPR describing the sources to which the model rules apply is being slightly revised to be clearer in response to some comments that the proposed language was not clear.

1. 25 MW Cut-Off

The EPA is retaining the 25 MW cut-off for EGUs for budget and model rule purposes. The EPA believes it is reasonable to assume no further control of air emissions from smaller EGUs. Available air emissions data indicate that the collective emissions from small EGUs are relatively small and that further regulating their emissions would be burdensome, to both the regulated community and regulators, given the relatively large number of such units. For example, NO_X and SO_2 emissions from EGUs of 25 MW or less in the CAIR region represent approximately one percent and two percent of total NO_X and SO_2 emissions from EGUs, respectively. There are over 4000 EGUs of 25 MW or less in the CAIR region. Consequently, EPA believes that administrative actions to control this large group with small emissions would be inordinate and thus does not believe these small units should be included. This approach of using a 25 MW cut-off for EGUs is consistent with existing SO_2 and NO_X cap and trade programs such as the NO_X SIP Call (where existing and new EGUs at or under this cut-off are, for similar reasons, not required to be included) and the Acid Rain Program (where this cut-off is applied to existing units and to new units combusting clean fuel). Also, EPA's New Source Performance Standards use an applicability threshold of approximately 25 MW under subpart Da.

One commenter suggested a plant-wide cut-off of 250 MW. This commenter suggested that including units between 25 and 250 MW would cause these units to shutdown but failed to provide any analysis to support its claim. Such a cut-off would be inconsistent with other existing SO_2 and NO_X cap and trade programs as noted above. The EPA estimates that approximately ⅓ of the SO_2 reductions, and 30 percent of the NO_X reductions, required under today's rule come from plants between 25 MW and 250 MW. Our modeling shows that some units below 250 MW will put on controls as part of our highly cost-effective set of control actions. The units also have the option to coal-switch, alter dispatch, and/or purchase allowances.

Another commenter suggested that, in lieu of the language proposed in the SNPR, EPA adopt a definition for EGU that, according to the commenter, is the Acid Rain Program's definition of affected utility. The commenter stated that the Acid Rain definition of EGU is ''all fossil fuel-fired units with a nameplate capacity greater than 25 MW supplying more than ⅓ of potential electrical output to the grid.'' However, the commenter misstated the Acid Rain definition and confused the Acid Rain applicability provisions concerning utility units in general with those provisions concerning cogeneration units in particular. The Acid Rain Program covers, with certain exceptions,[126] all existing fossil fuel-fired units greater than 25 MW that produce any electricity for sale; and new fossil fuel-fired units that produce any electricity for sale. The language referenced by the commenter concerning potential electrical output applies, in the Acid Rain Program, only to cogeneration units, not all fossil fuel-fired units. For non-cogeneration units, there is no exemption from Acid Rain Program requirements based on the unit selling a ''small'' amount of electricity for sale. The provisions in the NPR and the SNPR concerning cogeneration units are discussed below.

2. Definition of Fossil Fuel-Fired

The EPA is finalizing the proposed definition of fossil fuel-fired, *i.e.*, where any amount of fossil fuel is used at any time. This is the same definition that is used in the Acid Rain Program. One commenter suggested that the proposed definition is too broad and that EPA should use in the CAIR Program the same definition that is used in the NO_X SIP Call, *i.e.*, where a unit uses fossil fuel for at least 50 percent of its annual heat input during a specified period. The same commenter also proposed excluding large wood-fired boilers and black liquor recovery furnaces. The commenter's definition would result in units already subject to the Acid Rain Program in a given State being excluded from the CAIR Program and the model cap and trade rules applicable in that State. Such exclusion would make it more difficult to coordinate the Acid Rain Program and the CAIR Program. Consequently, EPA rejects the commenter's more restricted definition of fossil fuel-fired.

The EPA recognizes that new (*i.e.*, post-1990) units that are 25 MW or less and burn other than clean fuels are subject to the Acid Rain Program but not to the CAIR Program. However, there are very few such units, and EPA has decided to exclude any units that are 25 MW or less on other grounds discussed above.

3. Exemption for Cogeneration Units

As proposed, EPA is finalizing an exemption from the model cap and trade programs for cogeneration units, *i.e.*, units having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through sequential use of energy and meeting certain operating and efficiency standards (discussed below). The EPA is adopting the proposed definition of cogeneration unit and the proposed criteria for determining which cogeneration units qualify for the exemption from the model cap and trade programs.

The CAIR trading program has different applicability provisions for non-cogeneration units and cogeneration units. If a unit initially qualifies as a cogeneration unit, and for the exemption from the trading program for certain cogeneration units, but subsequently loses its cogeneration-unit status (*e.g.*, due to changes in operation), such unit loses the cogeneration-unit exemption and becomes subject to the applicability criteria for non-cogeneration units, regardless of any future changes in the unit or its operations. If, under the non-cogeneration unit applicability criteria, the unit becomes subject to the trading program, the unit will remain subject to the program in the future. Conversely if a unit initially does not qualify as a cogeneration unit, such unit becomes subject to the applicability criteria for non-cogeneration units, regardless of

[126] For example, certain cogeneration units and new units 25 MW or less that burn only clean fuel are exempt from the Acid Rain Program.

any future changes in the unit. If, under such criteria, the unit is subject to the trading program, the unit will remain subject to the program in the future. This approach to applicability means that units (other than, in some cases, opt-in units) cannot go in and out of the trading program, which, if allowed, would make it difficult for EPA, States, and owners or operators to determine which units should be complying with trading program requirements, and during what years, and would likely result in more non-compliance problems.

a. Efficiency Standard for Cogeneration Units

The EPA proposed operating and efficiency standards (*i.e.*, the useful thermal energy output of the unit must be no less than a certain percent of the total energy output and, in some cases, useful power must be no less than a certain percent of total energy input) in the SNPR that a unit must meet in order to qualify as a cogeneration unit. If the unit qualifies as a cogeneration unit, then it may be eligible for exemption from the CAIR, depending upon whether it meets additional operating criteria, discussed below. As discussed in the NPR, EPA proposed the same operating and efficiency standards for all fossil fuel-fired units (regardless of whether they burn coal, oil, or gas). In addition, not applying the operating and efficiency standards to coal-fired units would be counter productive to EPA's efforts to reduce SO_2 and NO_X emissions under this proposed rule because of the relatively high SO_2 and NO_X emissions from coal-fired units. In particular, without application of the efficiency standards to coal-fired units, highly inefficient coal-fired units, which have particularly high emissions per MWhr generated, could be exempt from the CAIR Program. In addition, if coal-fired units were not subject to the operating standard, the potential would exist for a coal-fired unit to provide only a token amount of useful thermal energy and still qualify for a cogeneration unit exemption from the CAIR Program, despite having relatively high emissions.

One commenter suggested that EPA should not use the efficiency standards for solid fuel-fired cogeneration units, because it may require some coal-fired cogeneration units that were exempt from the Acid Rain Program to purchase CAIR allowances. However, the EPA analysis indicates that most existing solid fuel-fired cogeneration units affected by this rule will meet the proposed standard. See TSD entitled ''Cogeneration Unit Efficiency Calculations'' in the docket. To the extent any solid fuel-fired cogeneration units cannot meet the efficiency standard and become affected units under the CAIR, EPA believes that, considering their relatively high emissions of SO_2 and NO_X compared to oil and gas-fired units, it is important to require these sources to meet the efficiency standards or be subject to the emission limits under the CAIR Program.

Another commenter suggested that the efficiency standards should not apply to solid fuel-fired cogeneration units because solid fuel-fired unit efficiency is based on HHV (higher heating value) while gas, or oil-fired unit efficiency is based on LHV (lower heating value). The EPA analyzed a range[127] of solid fuel-fired cogeneration units and calculated their efficiencies to see if they would meet the minimum efficiency standard. All of the units selected satisfied the proposed efficiency standard. See TSD entitled ''Cogeneration Unit Efficiency Calculations'' in the docket. As a result, EPA believes that most solid fuel-fired cogeneration units will meet the proposed efficiency standard. The efficiency standard EPA is adopting is the Public Utility Regulatory Act (PURPA) of thermal efficiency of 42.5 percent. See TSD entitled, ''Cogeneration Unit Efficiency Calculations'' for further discussion, is based on LHV. If the efficiency of a solid-fuel-fired unit is expressed in terms of HHV, it can easily be converted to LHV for purposes of determining whether it meets the efficiency standard. Therefore, the reason given by the commenter (that solid fuel-fired unit efficiency is expressed in terms of HHV) is not grounds for not applying an efficiency standard to these units. One commenter supported applying the same efficiency standard to solid fuel-fired units as EPA proposed. The EPA is finalizing its proposed cogeneration unit definition, which applies the same operating and efficiency standards to all units regardless of the type of fossil fuel burned.

b. One-third Potential Electric Output Capacity

The EPA is finalizing the ⅓ potential electric output capacity criteria in the NPR and SNPR. Under the proposals, the following cogeneration units are EGUs: Any cogeneration unit serving a generator with a nameplate capacity of greater than 25 MW and supplying more than ⅓ potential electric output capacity and more than 219,000 MW-hrs annually to any utility power distribution system for sale. These criteria are similar to those used in the Acid Rain Program to determine whether a cogeneration unit is a utility unit and the NO_X SIP Call to determine whether a cogeneration unit is an EGU or a non-EGU. The primary difference between the proposed criteria and the ⅓ potential electric criteria for the Acid Rain and NO_X SIP Call Programs is that these programs applied the criteria to the initial operation of the unit and then to 3-year rolling average periods while the proposed CAIR criteria are applied to each individual year starting with the commencement of operation. The EPA believes that using an individual year approach would streamline the application and administration of this exemption. No adverse comments were received on using an individual year approach as opposed to a 3-year rolling average. In addition, the criteria under the Acid Rain Program and the NO_X SIP Call are applied somewhat differently to units commencing construction on or before November 15, 1990 and units commencing construction after November 15, 1990. Several commenters suggested exempting all cogeneration units under the PURPA instead of using the proposed criteria and cite the high efficiency of cogeneration as a reason for a complete exemption. The EPA believes it is important to include in the CAIR Program all units, including cogeneration units, that are substantially in the business of selling electricity. The proposed ⅓ potential electric output criteria described above are intended to do that.

Inclusion of all units substantially in the electricity sales business minimizes the potential for shifting utilization, and emissions, from regulated to unregulated units in that business and thereby freeing up allowances, with the result that total emissions from generation of electricity for sale exceed the CAIR emissions caps. The fact that units in the electricity sales business are generally interconnected through their access to the grid significantly increases the potential for utilization shifting.

One commenter suggested that the ⅓ of potential electric output capacity criteria be applied on an annual basis. The EPA agrees that the criteria should be applied annually. The proposed and final model cap and trade rules adopt that approach.

c. Clarifying ''For Sale''

Several commenters requested EPA confirm that, for purposes of applying the ⅓ potential electric output criteria,

[127] The range included solid fuel-fired cogeneration units from 25 MW to 250 MW.

simultaneous purchases and sales of electricity are to be measured on a ''net'' basis, as is done in the Acid Rain Program. At least one commenter suggested that the net approach also be applied to purchase and sales that are not simultaneous. For purposes of applying the ⅓ potential electric output criteria in the CAIR Program and the model cap and trade rules, EPA confirms that the only electricity that counts as a sale is electricity produced by a unit that actually flows to a utility power distribution system from the unit. Electricity that is produced by the unit and used on-site by the electricity-consuming component of the facility will not count, including cogenerated electricity that is simultaneously purchased by the utility and sold back to such facility under purchase and sale agreements under the PURPA. However, electric purchases and sales that are not simultaneous will not be netted; the ⅓ potential electric output criteria will be applied on a gross basis, except for simultaneous purchase and sales. This is consistent with the approach taken in the Acid Rain Program.

d. Multiple Cogeneration Units

Some commenters suggested aggregating multiple cogeneration units that are connected to a utility distribution system through a single point when applying the ⅓ potential electric output capacity criteria. These commenters suggested that it is not feasible to determine which unit is producing the electricity exported to the outside grid. The EPA proposed to determine whether a unit is affected by the CAIR on an individual-unit basis. This unit-based approach is consistent with both the Acid Rain Program and the NO_X SIP Call. The EPA considers this approach to be feasible based on experience from these existing programs, including for sources with multiple cogeneration units. The EPA is unaware of any instances of cogeneration unit owners being unable to determine how to apply the ⅓ potential electric output capacity criteria where there are multiple cogeneration units at a source.

In a case where there are multiple cogeneration units with only one connection to a utility power distribution system, the electricity supplied to the utility distribution system can be apportioned among the units in order to apply the ⅓ potential electric output capacity criteria. A reasonable basis for such apportionment must be developed based on the particular circumstances. The most accurate way of apportioning the electricity supplied to the utility power distribution system seems to be apportionment based on the amount of electricity produced by each unit during the relevant period of time.

Exemption for Independent Power Production (IPP) Facilities: Some commenters stated that certain IPP facilities are exempt from the Acid Rain Program and that they should also be exempt from the CAIR Program and model-cap and trade rules. Under the Acid Rain Program, an IPP facility that has, as of November 15, 1990, a qualifying power purchase commitment (including a sales price) to sell at least 15 percent of planned net output capacity and has installed net output capacity not exceeding 130 percent of planned net output capacity is exempt. However, if the power purchase commitment changes after November 15, 1990 in a way that allows the cost of compliance with the Acid Rain Program to be shifted to the purchaser, then the IPP facility loses the exemption. For example, expiration or termination of the power purchase commitment or modification so that the price is increased (*e.g.*, changed to a market price) results in loss of the exemption. The purpose of the exemption is to protect IPP facilities subject to contract prices that were set before passage of the CAA Amendments of 1990 (including the Acid Rain Program in title IV) and that did not allow passthrough of the costs of Acid Rain Program compliance. However, EPA maintains that this exemption was aimed at easing the transition of such facilities into the Acid Rain Program and that there is no basis for maintaining this exemption for every subsequent cap and trade program. In addition, this exemption was not used in the NO_X SIP Call.

D. How Are Emission Allowances Allocated to Sources?

It is important to have consistency on a State-by-State basis with the basic requirements of the cap and trade approach when implementing a multi-State cap and trade program. This will ensure that: The integrity of the cap and trade approach is preserved so that the required emissions reductions are achieved; the compliance and administrative costs are minimized; and source owners and operators are equitably treated. However, EPA believes that some limited differences, such as allowance allocation methodologies for NO_X allowances, are possible without jeopardizing the environmental and other goals of the program.

1. Allocation of NO_X and SO_2 Allowances

Each State participating in EPA-administered cap and trade programs must develop a method for allocating (*i.e.*, distributing) an amount of allowances authorizing the emissions tonnage of the State's CAIR EGU budget. For NO_X allowances, each State has the flexibility to allocate its allowances however they choose, so long as certain timing requirements are met.

For SO_2, as noted in the January 2004 proposal, States will have no discretion in their allocation approach since the CAIR SO_2 cap and trade program uses title IV SO_2 allowances, which have been already allocated in perpetuity to individual units by title IV of the CAA.

a. Required Aspects of a State NO_X Allocation Approach

While it is EPA's intent to provide States with as much flexibility as possible in developing allocation approaches, there are some aspects of State allocations that must be consistent for all States. All State allocation systems are required to include specific provisions that establish when States notify EPA and sources of the unit-by-unit allocations. These provisions establish a deadline for each State to submit to EPA its unit-by-unit allocations for processing into the electronic allowance tracking system. Since the Administrator will then expeditiously record the submitted allowance allocations, sources will thereby be notified of, and have access to, allocations with a minimum lead time (about 3 years) before the allowances can be used to meet the NO_X emission limit.

Today's action finalizes the proposal to require States to submit unit-by-unit allocations of allowances for a given year no less than 3 years prior to January 1 of the allowance vintage year, which approach was supported by commenters.[128] Requiring States to submit allocations and thereby provide a minimum lead time before the allowances can be used to meet the NO_X emission limit ensures that an affected source—regardless of the State in the CAIR region in which the unit is located—will have sufficient time to plan for compliance and implement their compliance planning. Allocating allowances less than 3 years in advance of the compliance year may reduce a CAIR unit's ability to plan for and implement compliance and,

[128] If the deadline for States to submit SIPs is September of 2006, then this would result in notification period of less than 3 years for the first year of CAIR.

consequently, increase compliance costs. For example, a shorter lead time would reduce the period for buying or selling allowances and could prevent sources from participating in allowance futures markets, a mechanism for hedging risk and lowering costs.

Further, requiring a uniform, minimum lead-time for submission of allocations allows EPA to perform its allocation-recordation activities in a coordinated and efficient manner in order to complete expeditiously the recordation for the entire CAIR region and thereby promote a fair and competitive allowance market across the region.

These minimum requirements apply to the NO_X allocation approach and are not relevant for the SO_2 cap and trade program, which relies on title IV allowances.

b. Flexibility and Options for a State NO_X Allowance Allocations Approach

Allowance allocation decisions in a cap-and-trade program raise essentially distributional issues, as economic forces are expected to result in economically efficient and environmentally similar outcomes regardless of the manner in which allowances are initially distributed. Consequently, for CAIR NO_X allowances, States are given latitude in developing their allocation approach. NO_X allocation methodology elements for which States will have flexibility include:

A. The cost of the allowance distribution (*e.g.*, free distribution or auction);

B. The frequency of allocations (*e.g.*, permanent or periodically updated);

C. The basis for distributing the allowances (*e.g.*, heat-input or power output); and,

D. The use of allowance set-asides and their size, if used (*e.g.*, new unit set-asides or set-asides for energy efficiency, for development of Integrated Gasification Combined Cycle (IGCC) generation, for renewables, or for small units).

Some commenters have argued against giving States flexibility in determining NO_X allocations, citing concerns about complexity of operating in different markets and about the robustness of the trading system. The EPA maintains that offering such flexibility, as it did in the NO_X SIP Call, does not compromise the effectiveness of the trading program.

A number of commenters have argued against allowing (or requiring) the use of allowance auctions, while others did not believe that EPA should recommend auctions. For today's final action, while there are some clear potential benefits to using auctions for allocating allowances (as noted in the SNPR), EPA believes that the decision regarding utilizing auctions should ultimately be made by the States. Therefore, EPA is not requiring, restricting, or barring State use of auctions for allocating allowances.

A number of commenters supported allowing the use of allowance set-asides for various purposes. In today's final action, EPA is leaving the decision on using set-asides up to the States, so that States may craft their allocation approach to meet their State-specific policy goals.

i. Example Allowance Allocation Methodology

In the SNPR, EPA included an example (offered for informational guidance) of an allocation methodology that includes allowances for new generation and is administratively straightforward. In today's preamble, EPA is including in today's preamble, this ''modified output'' example allocations approach, as was outlined in the SNPR.

The EPA maintains that the choice of allocation methodology does not impact the achievement of the specific environmental goals of the CAIR Program. This methodology is offered simply as an example, and individual States retain full latitude to make their own choices regarding what type of allocation method to adopt for NO_X allowances and are not bound in any way to adopt EPA's example.

This example method involves input-based allocations for existing fossil units, with updating to take into account new generation on a modified-output basis. It also utilizes a new source set-aside for new units that have not yet established baseline data to be used for updating. Providing allowances for new sources addresses a number of commenter concerns about the negative effect of new units not having access to allowances.

Under the example method, allocations are made from the State's EGU NO_X budget for the first five control periods (2009 through 2013) of the model cap and trade program for existing sources on the basis of historic baseline heat input. Commenters expressed some concern regarding the proposed January 1, 1998 cut-off on-line date for considering units as existing units. The cut-off on-line date was selected so that any unit meeting the cut-off date would have at least 5 years of operating data, *i.e.*, data for 1998 through 2002 (which was the last year for which annual data was available). The EPA is still concerned with ensuring that particular units are not disadvantaged in their allocations by having insufficient operating data on which to base the allocations. The EPA believes that a 5 year window, starting from commencement of operation, gives units adequate time to collect sufficient data to provide a fair assessment of their operations. Annual operating data is now available for 2003. The EPA is finalizing January 1, 2001 as the cut-off on-line date for considering units as existing units since units meeting the cut-off date will have at least 5 years of operating data (*i.e.*, data for 2001 through 2005).

The allowances for 2014 and later will be allocated from the State's EGU NO_X budget annually, 6 years in advance, taking into account output data from new units with established baselines (modified by the heat input conversion factor to yield heat input numbers). As new units enter into service and establish a baseline, they are allocated allowances in proportion to their share of the total calculated heat input (which is existing unit heat input plus new units' modified output). Allowances allocated to existing units slowly decline as their share of total calculated heat input decreases with the entry of new units.

After 5 years of operation, a new unit will have an adequate operating baseline of output data to be incorporated into the calculations for allocations to all affected units. The average of the highest 3 years from these 5 years will be multiplied by the heat-input conversion factor to calculate the heat input value that will be used to determine the new unit's allocation from the pool of allowances for all sources.

Under the EPA example method, existing units as a group will not update their heat input. This will eliminate the potential for a generation subsidy (and efficiency loss) as well as any potential incentive for less efficient existing units to generate more. This methodology will also be easier to implement since it will not require the updating of existing units' baseline data. Retired units will continue to receive allowances indefinitely, thereby creating an incentive to retire less efficient units instead of continuing to operate them in order to maintain the allowances allocations.

Moreover, new units as a group will only update their heat input numbers once—for the initial 5-year baseline period after they start operating. This will eliminate any potential generation subsidy and be easier to implement, since it will not require the collection and processing of data needed for regular updating.

The EPA believes that allocating to existing units based on a baseline of historic heat input data (rather than output data) is desirable, because accurate protocols currently exist for monitoring this data and reporting it to EPA, and several years of certified data are available for most of the affected sources. The EPA expects that any problems with standardizing and collecting output data, to the extent that they exist, can be resolved in time for their use for new unit calculations. Given that units keep track of electricity output for commercial purposes, this is not likely to be a significant problem.

A number of commenters expressed support for EPA's proposal in the SNPR that the heat input data for existing units be adjusted by multiplying it by different factors based on fuel-type. Contrary to some commenters' claims, determining allocations with fuel factors would not create disincentives for efficiency. With the use of a single baseline for existing units, neither adjusted input, nor input, nor output based allocations would provide additional incentives for energy efficiency. All sources have incentives to reduce emissions (improving efficiency is a way of doing this) as a result of the cap and trade program, not because of the choice of an allocation based on a single historic baseline.

The EPA acknowledges that since allowances have value, different allocations of allowances clearly do impact the distribution of wealth among different generators. However, in general, the economics of power generation dictate that generators selling power will seek to operate (and burn fuel) to meet energy demand in a least-cost manner. The cost of the power generated (reflecting the bid price per megawatt hour) will include the cost of allowances to cover emissions, whether the generator uses allowances that it already owns, or whether it needs to purchase additional allowances. With a liquid market for allowances, allocations for existing sources (whose baseline does not change) are a sunk benefit or sunk cost, not impacting the existing generator's behavior on the margin. Thus, the use of fuel factors in our allocating method would not be expected to result in changes in generators' choices for fuel efficiency.

In its example allocation approach, EPA is including adjustments of heat input by fuel type based on average historic NO_X emissions rates by three fuel types (coal, natural gas, and oil) for the years 1999–2002. As noted in the SNPR, such calculations would lead to adjustment factors of 1.0 for coal, 0.4 for gas and 0.6 for oil. The factors would reflect the inherently different emissions rates of different fossil-fired units (and consequently also reflect the different burdens to control emissions.

However, allocating to new (not existing) sources on the basis of input (and particularly fuel-adjusted heat input) would serve to subsidize less-efficient new generation. For a given amount of generation, more efficient units will have the lower fuel input or heat input. Allocating to new units based on heat input could encourage the building of less efficient units since they would get more allowances than an equivalent efficient, lower heat-input unit. The modified output approach, as described below, will encourage new, clean generation, and will not reward less efficient new coal units or less efficient new gas units.

Under the example method, allowances will be allocated to new units of each fuel-type with an appropriate baseline on a ''modified output'' basis. The new unit's modified output will be calculated by multiplying its gross output by a heat rate conversion factor of 7,900 btu/kWh for coal units and 6,675 btu/kWh for oil and gas units. The 7,900 btu/kWh value for the conversion factor for new coal units is an average of heat-rates for new pulverized coal plants and new IGCC coal plants (based upon assumptions in EIA's Annual Energy Outlook (AEO) 2004 [129]). The 6,675 btu/kWh value for the conversion factor for new gas units is an average of heat-rates for new combined cycle gas units (also based upon assumptions in EIA's AEO 2004). A single conversion rate for each fuel-type will create consistent and level incentives for efficient generation, rather than favoring new units with higher heat-rates.

For new cogeneration units, their share of the allowances will be calculated by converting the available thermal output (btu) of useable steam from a boiler or useable heat from a heat exchanger to an equivalent heat input by dividing the total thermal output (btu) by a general boiler/heat exchanger efficiency of 80 percent.

New combustion turbine cogeneration units will calculate their share of allowances by first converting the available thermal output of useable steam from a heat recovery steam generator (HRSG) or useable heat from a heat exchanger to an equivalent heat input by dividing the total thermal output (btu) by the general boiler/heat exchanger efficiency of 80 percent. To this they will add the electrical generation from the combustion turbine, converted to an equivalent heat input by multiplying by the conversion factor of 3,413 btu/kWh. This sum will yield the total equivalent heat input for the cogeneration unit.

Steam and heat output, like electrical output, is a useable form of energy that can be utilized to power other processes. Because it would be nearly impossible to adequately define the efficiency in converting steam energy into the final product for all of the various processes, this approach focuses on the efficiency of a cogeneration unit in capturing energy in the form of steam or heat from the fuel input.

Commenters expressed concern about a single conversion factor, arguing for different factors for different fuels and technologies. The EPA recognizes these concerns and agrees that different new fossil-generation units have inherently different heat rates, largely dictated by the technology needed to burn different fuels. A single conversion rate for all units would provide new gas-fired combined cycle units with relatively more allowances, relative to their emissions, than it would for new coal-fired units.

The EPA maintains that providing each new source an equal amount of allowances per MWh of output, given the fuel it is burning, is an equitable approach. Since electricity output is the ultimate product being produced by EGUs, a single conversion factor for each fuel, based on output, ensures that all new sources burning a particular fuel will be treated equally.

Some commenters support allocating allowances to all new generation, not just fossil fuel-fired CAIR units. The EPA notes that including new non-CAIR and non-fossil units in the allowance distribution would raise issues, about which EPA lacks sufficient information for resolution at this time for EPA's example method. It would be necessary to clearly define what types of generating facilities that could participate and what would constitute ''new'' non-fossil generation.[130] Commenters did not provide any analysis of the impact of possible definitions on generation mix, or electricity markets. Further, in order to include all generation, there would be a need to establish application and data

[129] Energy Information Administration, ''Annual Energy Outlook 2004, With Projections to 2025'', January 2004. Assumptions for the NEMS model. *http://www.eia.doe.gov/oiaf/archive/aeo04/assumption/tbl38.html*.

[130] Some commenters stated that, if allocations were provided for non-emitting new generation, they also should be provided to all such generation, including nuclear units.

collections procedures and determine appropriate size cut-offs and boundaries of this generation—since in many such instances there is no clear analog to discrete fossil ''units.'' [131] There also are associated issues about developing appropriate measurement and data reporting requirements for such sources. Commenters supporting this approach did not address any of these matters in any detail. However, EPA encourages States that are interested in including such units in their updating allocations to consider potential solutions and include them in their SIPs. Under the example method, new units that have entered service, but have not yet started receiving allowances through the update, will receive allowances each year from a new source set-aside. The new source allowances from the set-aside will be distributed based on their actual emissions from the previous year. Such an allocation approach will generally provide new units sufficient allowances to cover their emissions during the interim period before the units are allocated allowances on the same basis as existing units.

Today's example method includes a new source set-aside equal to 5 percent of the State's emission budget for the years 2009–2013 and 3 percent of the State's emission budget for the subsequent years. In the SNPR, EPA proposed a level 2 percent set-aside for all years.

Commenters noted their concern that the amount of the set-aside in the early years of the program should be higher to reflect the fact that the set-aside will initially need to accommodate all new units entering into service from 1998 through 2010.[132] In order to estimate the need for allocations for new units, EPA looked at the NO_X emissions from units that went online starting in 1999 as projected by the Integrated Planning Model (IPM) runs modeling CAIR for the years 2010 and 2015. These IPM emissions projections indicated over 57,000 tons of NO_X emissions in 2010 and about 74,000 tons of NO_X emission by 2015 from new sources need to be covered under set-asides throughout the CAIR region. The 2010 number represents almost 4 percent of the Phase I NO_X regional cap, while the 2015 number represents about 6 percent of the Phase I regional cap. Consequently, today's example method includes a 5 percent set-aside for the initial period (2009–2013). It should be noted that by 2014, the set-aside would need to cover new sources from the entire period 2004–2013.

The choice of a 3 percent new source set-aside, starting in 2014, reflects concerns that adequate allowances be provided for the 10 years of new units to be covered by the set-aside in 2014 and subsequent years. (The set-aside in 2014, for example, would need to accommodate all units that went on-line between 2004 and 2013).

Individual States using a version of the example method may want to adjust this initial 5 year set-aside amount to a number higher or lower than 5 percent to the extent that they expect to have more or less new generation going on-line during the 2001–2013 period. They may also want to adjust the subsequent set-aside amount to a number higher or lower than 3 percent to the extent that they expect more or less new generation going on-line after 2004. States may also want to set this percentage a little higher than the expected need, since, in the event that the amount of the set-aside exceeds the need for new unit allowances, the State may want to provide that any unused set-aside allowances will be redistributed to existing units in proportion to their existing allocations.

For the example method, EPA is finalizing the approach that new units will begin receiving allowances from the set-aside for the control period immediately following the control period in which the new unit commences commercial operation, based on the unit's emissions for the preceding control period. Thus, a source will be required to hold allowances during its start-up year, but will not receive an allocation for that year.

States will allocate allowances from the set-aside to all new units in any given year as a group. If there are more allowances requested than in the set-aside, allowances will be distributed on a pro-rata basis. Allowance allocations for a given new unit in following years will continue to be based on the prior year's emissions until the new unit establishes a baseline, is treated as an existing unit, and is allocated allowances through the State's updating process. This will enable new units to have a good sense of the amount of allowances they will likely receive—in proportion to their emissions for the previous year. This methodology will not provide allowances to a unit in its first year of operation; however it is a methodology that is straightforward, reasonable to implement, and predictable.

In the SNPR, the example method from the NO_X SIP Call model rule was proposed as an alternate approach.[133] However, the EPA has found this approach to be complicated for both the States and the EPA to implement. Additionally, the NO_X SIP Call approach would introduce a higher level of uncertainty for sources in the allocation process than necessary.

While the EPA is offering an example allocation method with accompanying regulatory language, the EPA reiterates that it is giving States' flexibility in choosing their NO_X allocations method so they may tailor it to their unique circumstances and interests. Several commenters, for instance, have noted their desire for full output-based allocations (in contrast to the hybrid approach in the example above). In the past, EPA had sponsored a work group to assist States wishing to adopt output-based NO_X allocations for the NO_X SIP Call and believes it is a viable approach worth considering. Documents from meetings of this group and the resulting guidance report (found at *http://www.epa.gov/airmarkets/fednox/workgrp.html)* together with additional resources such as the EPA-sponsored report ''Output-Based Regulations: A Handbook for Air Regulators'' (found at *http://www.epa.gov/cleanenergy/pdf/output_rpt.pdf*) can help States, should they choose to adopt any output-based elements in their allocation plans.

As an another alternative example, States could decide to include elements of auctions into their allowance allocation programs.[134] An example of an approach where CAIR NO_X allowances could be distributed to sources through a combination of an auction and a free allocation is provided below.

During the first year of the trading program, 94 percent of the NO_X allowances could, for example, be allocated to affected units with an auction held for the remaining 1 percent of the NO_X allowances [135]. Each subsequent year, an additional 1 percent of the allowances (for the first 20 years of the program), and then an additional 2.5 percent thereafter, could be auctioned until eventually all the allowances are auctioned. With such a system, for the first 20 years of the

[131] For instance, would the addition of a single new wind turbine at a wind-farm constitute a ''new unit''?

[132] As noted earlier in this section, EPA is now considering new units to be those that went online after January 1, 2001 rather than 1998.

[133] With the alternate approach from the NO_X SIP Call. States could distribute a new source set-aside for a control period based on full utilization rates, at the end of the year the actual allowance allocation would be adjusted to account for actual unit utilization/output, and excess allowances would be returned and redistributed, first taking into account new unit requests that were not able to be addressed.

[134] Auctions could provide States with a non-distortionary source of revenue.

[135] 5 percent of the allowances would go to a new source set-aside.

trading programs, the majority of allowances would be distributed for free via the allocation. Allowances allocated for these earlier years are generally more valuable than allowances allocated for later years because of the time value of money. Thus, most emitting units would receive relatively more allowances in the early years of the program, when they are facing the expenses of taking actions to control their emissions. Even though the proportion of allowances allocated to existing sources declines in the later years of the program, these sources receive for free a very significant share of the total value of allowances (because the discounted present value of allowances allocated in the early years of the program is greater than the discounted present value of the allowances auctioned later).

Auctions could be designed by the State to promote an efficient distribution of allowances and a competitive market. Allowances would be offered for sale before or during the year for which such allowances may be used to meet the requirement to hold allowances. States would decide on the frequency and timing of auctions. Each auction would be open to any person, who would submit bids according to auction procedures, a bidding schedule, a bidding means, and by fulfilling requirements for financial guarantees as specified by the State. Winning bids, and required payments, for allowances would be determined in accordance with the State program and ownership of allowances would be recorded in the EPA Allowance Tracking System after the required payment is received.

The auction could be a multiple-round auction. Interested bidders would submit before the auction, one or more initial bids to purchase a specified quantity of NO_X allowances at a reserve price specified by the State, specifying the appropriate account in the Allowance Tracking System in which such allowances would be recorded. Each bid would be guaranteed by a certified check, a funds transfer, or, in a form acceptable to the State, a letter of credit for such quantity multiplied by the reserve price. For each round of the auction, the State would announce current round reserve prices for NO_X and determine whether the sum of the acceptable bids exceeds the quantity of such allowances, available for auction. If the sum of the acceptable bids for NO_X allowances exceeds the quantity of such allowances the State would increase the reserve price for the next round. After the auction, the State would publish the names of winning and losing bidders, their quantities awarded, and the final prices. The State would return payment to unsuccessful bidders and add any unsold allowances to the next relevant auction.

In summary, today's action provides, for States participating in the EPA-administered CAIR NO_X cap and trade program, the flexibility to determine their own methods for allocating NO_X allowances to their sources. Specifically, such States will have flexibility concerning the cost of the allowance distribution, the frequency of allocations, the basis for distributing the allowances, and the use and size of allowance set-asides.

E. What Mechanisms Affect the Trading of Emission Allowances?

1. Banking

a. The CAIR NPR and SNPR Proposal for the Model Rules and Input From Commenters

Banking is the retention of unused allowances from 1 calendar year for use in a later calendar year. Banking allows sources to make reductions beyond required levels and ''bank'' the unused allowances for use later. Generally speaking, banking has several advantages: It can encourage earlier or greater reductions than are required from sources, stimulate the market and encourage efficiency, and provide flexibility in achieving emissions reductions goals. When sources reduce their SO_2 and NO_X emissions in the early phases, the cap and trade program creates an emissions ''glide path'' that provides earlier environmental benefits and lower cost of compliance. This ''glide path'' does allow emissions to exceed the cap and trade program budget—especially in the initial years after the adoption of a more stringent cap. The use of banked allowances from the Acid Rain and NO_X SIP Call Programs in the CAIR NO_X and SO_2 cap and trade programs is discussed below in section VIII.F of this preamble.

The January 30, 2004 CAIR NPR and June 10, 2004 CAIR SNPR proposed that the CAIR NO_X and SO_2 cap and trade programs allow banking and the use of banked allowances without restrictions. Allowing unrestricted banking and the use of banked allowances is consistent with the existing Acid Rain SO_2 cap and trade program. The NO_X SIP Call cap and trade program, however, has some restrictions on the use of banked allowances, a procedure called ''flow control,'' described in detail in the June 10, 2004 CAIR SNPR.

Comments Regarding Unrestricted Banking After the Start of the CAIR NO_X and SO_2 Cap and Trade Programs

Many commenters supported the EPA's proposal to allow unrestricted banking and the use of banked allowances for both SO_2 and NO_X, agreeing that flow control is a complex and confusing procedure with undemonstrated environmental benefit. Further, they agreed that banking with no restrictions on use will encourage early emissions reductions, stimulate the trading market, encourage efficient pollution control, and provide flexibility to affected sources in meeting environmental objectives.

Other commenters objected to the EPA's proposal to allow unrestricted use of banked allowances. All of these commenters supported some use of flow control in the CAIR cap and trade programs, most supporting its use for both SO_2 and NO_X.

Some commenters disagreed with the EPA's assessment that the use of flow control in the Ozone Transport Commission (OTC) cap and trade program was complicated to understand and implement and caused market complexity. One commenter further elaborated that flow control was accepted by industry. Another commenter claimed that the EPA has not analyzed the impact of the flow control mechanism.

Some commenters supportive of flow control stated that flow control was ''successful'' in the OTC and NO_X SIP Call trading programs and ''worked well'' and ''achieved the desired effect,'' without supporting those statements.

b. The Final CAIR Model Rules and Banking

The EPA acknowledges that the OTC NO_X cap and trade program has functioned for several years despite the complexity introduced by the flow control procedures. Industry and other allowance traders have adapted to these complex procedures, yet there are ongoing questions from the regulated community about how the procedures actually work. As an example, one commenter, while disagreeing with the EPA's assertion that flow control is overly complex, goes on to describe incorrectly the implementation of flow control. The NO_X SIP Call cap and trade program includes similar procedures but flow control was not triggered in the first 2 years of the program (2003 and 2004), so there is no experience to be drawn from that program.

The EPA maintains that the benefits of utilizing these complex procedures is questionable. The EPA has analyzed the use of the flow control procedures in a paper released in March 2004, ''Progressive Flow Control in the OTC NO_X Budget Program: Issues to Consider at the Close of the 1999 to 2002 Period.'' The lessons learned from this analysis were as follows:

(1) Flow control can create market pricing complexity and uncertainty. The need for implementation of flow control for a particular control period is not known more than a few months in advance, and the value of banked allowances varies from year to year, depending on whether flow control has been triggered for the particular year. Therefore, when deciding how much to control, a source has some increased uncertainty about the value of any excess allowances it generates.

(2) Flow control can have a bigger impact on small entities than on large entities. Large firms with multiple allowance accounts can shift banked allowances among those accounts to minimize the number of banked allowances surrendered at a discounted rate.

(3) Flow control does not directly affect short-term emissions, so it may not serve the environmental goals for which it was created.

Incorporating these lessons learned, the EPA is finalizing the CAIR NO_X and SO_2 cap and trade programs with no flow control mechanism.

2. Interpollutant Trading Mechanisms

a. The CAIR NPR Proposal for the Model Rules and Input From Commenters

Mechanisms for interpollutant trading allow reduced emissions of one pollutant to be exchanged for increased emissions of another pollutant where both pollutants cause the same environmental problem (*e.g.*, are precursors of a third pollutant). Interpollutant trading mechanisms are typically based upon each precursor's contribution to a particular environmental problem and are often controversial and scientifically difficult to design because of the complexities of environmental chemistry. Determination of conversion factors (*i.e.*, transfer ratios that relate the impact of one pollutant to the impact of another pollutant) can be dependent upon location, the presence of other pollutants that are necessary for chemical reactions, the time of emissions, and other considerations.

The January 30, 2004 CAIR NPR did not propose a specific interpollutant trading mechanism but rather took comment on interpollutant trading in general as well as the following specific issues:

(1) What would be the exchange rate (*i.e.*, the transfer ratio) for the two pollutants,

(2) How can the transfer ratio best achieve the goals of $PM_{2.5}$ and ozone reductions in downwind States and,

(3) How would the interpollutant trading accommodate the different geographic regions of the $PM_{2.5}$ and ozone programs?

Comments Regarding the Potential Interpollutant Trading

The EPA received several comments on interpollutant trading with the most commenters generally opposed to including provisions to allow for the interchangability of SO_2 and NO_X allowances.

Several commenters pointed out that the CAIR ozone attainment benefits result from the NO_X emissions reductions, and contend that the EPA has not shown that SO_2 emissions impact ozone. Therefore, the commmenters conclude that it would be inappropriate for SO_2 allowances to be traded and used for compliance with the NO_X cap. Some commenters supported the consideration or use of interpollutant trading if it was one-directional, *i.e.*, NO_X allowances could be used for compliance with the SO_2 allowance holding requirements, but not vice versa. This could result in fewer NO_X emissions and more SO_2 emissions.

Some commenters supported the consideration or use of interpollutant trading and emphasized the scientific difficulty in developing accurate transfer ratios. Of these commenters, some added that interpollutant trading would be appropriate if the EPA conducted a thorough analysis of the potential impacts that interpollutant trading would have on: nonattainment areas' ability to come into attainment; the allowance markets and prices; and the integrity of the NO_X caps in light of the potentially large SO_2 allowance bank that might be carried forward into the CAIR trading programs.

A few commenters noted that the EPA is directed by the CAA to study interpollutant trading and has approved SIPs that allow the trading of ozone precursors under specific circumstances.

b. Interpollutant Trading and the Final CAIR Model Rules

Interpollutant trading can provide some additional compliance flexibility, and potentially lower compliance costs, if appropriately applied to multiple pollutants that have reasonably well known impacts on the same environmental problem. The EPA acknowledges that it has the authority to create interpollutant trading programs and has done so, in other regulatory contexts, in the past. However, for several reasons, the EPA determined that direct interpollutant trading is not appropriate in the CAIR.

The final CAIR includes separate annual SO_2 and annual NO_X model rules to address $PM_{2.5}$ precursor emissions, and an ozone-season NO_X model rule to address summertime ozone precursor emissions. The EPA believes it is not appropriate for the CAIR model rules to allow annual SO_2 or NO_X allowances to be used for compliance with ozone-season NO_X allowance holding requirements because this has the potential to adversely impact the ozone-season emissions reductions and ozone air quality improvements from CAIR. This is significant because the EPA, as required by the CAA, has promulgated a national air quality standard for 8-hour ozone based on a determination that the standard is necessary to protect public health. Section 110(a)2(D) requires States to prohibit emissions in amounts that will significantly contribute to nonattainment in, or interfere with maintenance by, any other State with respect to any air quality standard, including ozone. In this rule, EPA has designed the annual (SO_2 and NO_X) and ozone-season (NO_X) emission caps to achieve the emissions reductions necessary to address each State's significant contribution to downwind $PM_{2.5}$ and ozone nonattainment, respectively, and to prevent interference with maintenance. If sources were permitted to use annual SO_2 or annual NO_X allowances for compliance with ozone-season NO_X allowance holding requirements (*i.e.*, the ozone-season NO_X cap), then there would be no assurance that upwind States' ozone-season NO_X reduction obligations would be met, and CAIR's projected ozone improvements in downwind nonattainment areas could be significantly reduced. As a result, should interpollutant trading be permitted between the annual and ozone-season programs, the EPA could not demonstrate that the use of a CAIR ozone-season cap and trade program would result in the emissions reductions necessary to satisfy upwind States' obligations under section 110(a)2(D)to reduce NO_X for ozone purposes.

The EPA believes it is also inappropriate to use annual NO_X allowances for compliance with the annual SO_2 allowance holding requirements, and vice versa. The EPA agrees with commenters that emphasize that the chemical interactions for $PM_{2.5}$ precursors are scientifically complex and must be accurately reflected in any transfer ratio in order to maintain the integrity of the market. For example, EPA analysis has shown (see January 30, 2004 NPR) that $PM_{2.5}$ precursors, such as NO_X and SO_2, may have non-linear interactions in the formation of $PM_{2.5}$. Any uniform, interpollutant transfer ratio would have to be an average and would introduce significant variability concerning the impact of interpollutant trading on emissions and significant uncertainty concerning the achievement of the CAIR Program's emission reduction goals. The EPA did not receive a response to the request in the January 30, 2004 NPR for information on an appropriate value for a potential transfer ratio. While the EPA did receive one comment that recommended the use of a trading ratio of two NO_X allowances for one SO_2 allowance, no comments presented supporting analysis that could be used to develop transfer ratios.

While many commenters supportive of allowing interpollutant trading in the CAIR claimed that it would provide additional compliance flexibility to sources, the EPA contends that use of the newly created CAIR trading markets is sufficiently flexible. Sources may develop integrated, multi-pollutant control strategies and use the separate allowance markets to mitigate differences in control costs (within the boundaries of emissions caps). In other words, a source can choose the level to which they can cost effectively control one pollutant and, if necessary, buy or sell emission allowances of the other pollutant to compensate for any expensive or inexpensive control cost. When markets are used to provide for trading of multiple pollutants, sources benefit from the additional compliance flexibility while the caps assure the achievement of the overarching environmental goals.

In the June 10, 2004 SNPR, the EPA solicited comment on how an interpollutant trading mechanism might accommodate the slightly different geographic regions found to be significant contributors for $PM_{2.5}$ and ozone under the CAIR. No commenters provided supporting analysis or input on this issue.

In summary, the EPA received comments that generally opposed including a specific interpollutant trading mechanism. No commenters provided analysis to demonstrate the benefit of including a specific interpollutant trading mechanism nor was there analysis provided in response to the EPA's solicitation in the June 10, 2004 SNPR for input on: Transfer ratios, addressing two different environmental issues, and having slightly different annual NO_X and ozone season NO_X control regions. Furthermore, because the NO_X and SO_2 markets provide very flexible mechanisms for trading of the two pollutants, the EPA does not believe there is a compelling need to go further at this time. Therefore, EPA is not finalizing provisions in the CAIR model rules that specifically address interpollutant trades.

F. Are There Incentives for Early Reductions?

When sources reduce their SO_2 and NO_X emissions prior to the first phase of a multi-phase cap and trade program, it creates the emissions ''glide slope'' of a cap and trade approach that provides early environmental benefit and lowers the cost of compliance. Early reduction credits (ERCs) can provide an incentive for sources to install and/or operate controls before the implementation dates. Allowing emission allowances from existing programs to be used for compliance in the new program is another mechanism to encourage early reductions prior to the start of a cap and trade program. This section discusses the potential use of mechanisms to provide incentives for early reductions in the CAIR.

1. Incentives for Early SO_2 Reductions

a. The CAIR NPR and SNPR Proposal for the Model Rules and Input From Commenters

The January 30, 2004 CAIR NPR and June 10, 2004 CAIR SNPR acknowledge the benefit of early reductions and provide for the use of title IV SO_2 allowances of vintage years 2009 and earlier to be used for compliance in the CAIR at a one-to-one ratio. In other words, title IV allowances can be banked into the CAIR Program. This provides incentive for title IV sources to reduce their emissions in years 2009 and earlier because these allowances may be used for CAIR compliance without being discounted by the retirement ratios applied to the 2010 and later SO_2 allowances. No other mechanism, such as SO_2 ERCs were proposed by the EPA.

Comments Regarding the Incentives for Early SO_2 Reductions

The EPA received comments on incentives for early SO_2 reductions with the majority supporting the EPA proposal to encourage early emission reductions by allowing the CAIR sources to use 2009 and earlier vintage title IV SO_2 allowances for CAIR compliance. Some supporters noted concerns in meeting the CAIR's stringent Phase I SO_2 requirements as another reason to allow the banking of undiscounted, title IV allowances into the CAIR.

Some commenters expressed concern that achieving the SO_2 caps would be delayed if a large number of SO_2 allowances were being banked into the CAIR. Based upon experience with implementing the Acid Rain Program, the EPA acknowledged in the SNPR that crediting early reductions does create a glide slope—where emissions are reduced below the baseline before the implementation date and ''glide'' down to the ultimate cap level sometime after the program begins. This gradual reduction in emissions is a key component to cap and trade programs having lower cost of compliance than command-and-control approaches. One commenter proposed that the EPA needs to assess the likelihood that allowing the banking of undiscounted title IV allowances would delay the attainment of the Phase I SO_2 cap until Phase II. Because the EPA included this mechanism (*i.e.*, the use of 2009 and earlier vintage SO_2 allowances for compliance in the CAIR) in the policy case modeled as part of this rulemaking, EPA analysis includes the benefits and costs that would result from the level of SO_2 reductions that would take place with banking of undiscounted title IV allowances.

One commenter advocated the use of SO_2 ERCs. It was not clear whether these would be awarded in addition to banking title IV allowances into the CAIR or the ERC mechanism would take the place of banking SO_2 allowances into the CAIR.

b. SO_2 Early Reduction Incentives in the Final CAIR Model Rules

The CAIR SO_2 model rule allows CAIR sources to use title IV SO_2 allowances of vintage 2009 and earlier for compliance with the CAIR at a one-to-one ratio. This approach was part of the CAIR policy case assumptions used in the rulemaking modeling and the EPA has shown that the SO_2 cap and trade program, with this early incentive mechanism, will achieve the level of SO_2 reductions needed to meet the CAIR goals. These reductions take place on a glide slope that includes early emissions reductions as well as some use of the SO_2 allowance bank as sources gradually reduce emissions toward the cap levels.

The EPA did not include SO_2 ERCs because the Acid Rain Program cap and trade program, which affects a large segment of the CAIR source universe, makes it impossible to determine whether sources are reducing their SO_2

emissions below levels required by existing (*i.e.*, the Acid Rain Program) programs. Furthermore, given that most sources with substantial emissions receive SO_2 emission allowances under the Acid Rain Program, a significant number of SO_2 allowances are expected to be banked into the CAIR. These banked allowances would be available to CAIR sources in the early years of the program and make ERCs largely unnecessary.

2. Incentives for Early NO_X Reductions

a. The CAIR NPR and SNPR Proposal for the Model Rules and Input From Commenters

In the June 10, 2004 SNPR, the EPA proposed to provide incentives for early NO_X reductions by allowing the use of NO_X SIP Call allowances of vintage 2009 and earlier to be used for compliance in the CAIR. Further, the EPA did not propose, but solicited comment on the potential use of NO_X ERCs to provide an additional incentive for sources to reduce NO_X emissions prior to CAIR implementation. In addition to the general solicitation for comment on NO_X ERCs, the EPA solicited input on the following specific approaches that could be utilized: (1) The EPA could maintain the NO_X SIP Call requirements and allow sources to use ERCs only for compliance with the annual limitation, to ensure that ozone-season NO_X limitations are met. Under this scenario, the additional States subject to the CAIR that have been found to significantly contribute to ozone nonattainment may also have to be included in the ozone season cap; (2) the EPA could limit the period of time during which ERCs could be created and banked; (3) the EPA could cap the amount of ERCs that can be created; and (4) the EPA could apply a discount rate to ERCs.

Comments Regarding the Incentives for Early NO_X Reductions

The EPA did not receive comment on the proposed use of NO_X SIP Call allowances of vintage years 2009 and earlier for compliance in the CAIR. In fact, several commenters characterized the CAIR proposal as not including any incentives for early NO_X emissions reductions.

The EPA received several comments on the potential use of NO_X ERCs with the majority in favor of some sort of ERC mechanism. Several commenters advocated the use of ERCs to mitigate concerns that they would not be able to meet the stringent Phase I CAIR reduction requirements. One commenter wanted early reductions to facilitate the ozone attainment in 2010 but believed 2010 attainment could only be helped if there were some restrictions on the number of ERCs that could be created.

Some ERC supporters wanted credit for wintertime emissions reductions only, while a few believed that credit should be given for reductions at any time of year. One commenter advocated providing ERCs for wintertime reductions only as part of a broader proposal to create a bifurcated NO_X trading system (*i.e.*, separate wintertime and summertime allowances and trading markets).

Many of the commenters supporting the use of ERCs advocated that they be distributed from a pool of allowances similar to the CSP used in the NO_X SIP Call. (The NO_X SIP Call CSP was a fixed pool of NO_X allowances that were distributed on a first come-first serve, prorated, or need basis, depending upon the State). Commenters noted that the CSP approach has already been part of a litigated rulemaking and provides the added benefit of limiting the total number of allowances that can be distributed for early reductions. Other commenters proposed that should the final approach use a pool of allowances, this pool should not remove allowances from the existing State NO_X budget. Another commenter suggested that allowances from a CSP could be distributed based upon a NO_X emission rate, such as 0.25 lbs/mmBtu. Allowances could be distributed to any source emitting below the target emission rate.

Several commenters were concerned that too many NO_X ERCs (as well as NO_X SIP Call allowances) could be introduced into the CAIR and the ability of the NO_X cap and trade program to meet the annual and ozone-season reduction goals could be compromised. Some commenters suggested that crediting early reductions at a discount (*e.g.*, 2 tons of NO_X reductions earn 1 ERC) could mitigate this concern. Other commenters noted that a CSP-style mechanism also provides safeguards against an overabundance of ERCs. Another commmenter noted that restrictions on the use of ERCs similar to the progressive flow control (PFC) mechanism used in the NO_X SIP Call—PFC restricts the use of banked NO_X allowances for compliance in years where the NO_X bank is greater than 10 percent of the allocations—could help to ease concerns of flooding the market with NO_X ERCs.

One commenter believed that the EPA's projection that the potential pool of NO_X ERCs could be as large as 3.7 million tons (presented in the June 10, 2004 SNPR) is unrealistically high. The commenter contended that technical limitations of Selective Catalytic Reduction (SCR) operation would not permit facilities to simply run all of their SCRs year-round. More specifically, the commenter believes the lower operating loads, typically of the wintertime dispatch, would not meet the minimum conditions necessary for SCR operation (*i.e.*, at lower capacity the stack gas temperatures will not support the use of the catalyst). Fewer wintertime opportunities to operate the SCRs is believed by the commenter to result in a smaller projected ERC estimate. This was an estimate used for discussion purposes and was not directly used in the development of the CSP.

A few commenters advocated providing credits to any source that reduced emission rates below those used to determine the CAIR State budgets. One commenter suggested that the rates be based on those rates used to determine the NO_X SIP Call caps.

A few commenters proposed that the EPA should develop a strategy for crediting NO_X reductions from sources that have implemented control measures in response to State-level regulations that are more stringent than the NO_X SIP Call. Another commenter advocated only providing ERCs in States subject to both the NO_X SIP Call and the CAIR.

Some commenters did not support the use of NO_X ERCs in any form. These commenters believe that the use of ERCs would delay attainment of the CAIR emission caps.

b. NO_X Early Reduction Incentives in the Final CAIR Model Rules

The CAIR ozone-season NO_X cap and trade rule will allow the proposed use of NO_X SIP Call allowances of vintage years 2008 and earlier for compliance in the CAIR. This mechanism would provide incentive for sources in NO_X SIP Call States to reduce their ozone-season NO_X emissions and bank additional allowances into the CAIR. Because today's final ozone-season cap and trade rule includes a mandatory ozone-season NO_X cap in 2009 (this modification is discussed in section IV), the provisions to allow the banking of NO_X SIP Call allowances into the CAIR are adjusted to reflect this implementation date.

The CAIR annual NO_X cap and trade rule will provide additional incentives for early annual NO_X reductions by creating a CSP for CAIR States from which they can distribute allowances for early, surplus NO_X emissions reductions in the years 2007 and 2008. The earning of CAIR CSP allowances for

NO_X emission reductions does not begin until 2007 because this is the first year after the State SIP submittal deadlines. The CAIR CSP will provide a total of 200,000 [136] CAIR annual NO_X allowances of vintage 2009 in addition to the annual CAIR NO_X budgets.

The CAIR's CSP is patterned after the NO_X SIP Call's CSP, which is part of an established and extensively litigated rulemaking. Similarities include: Limiting the total number of allowances that can be distributed; limiting the years in which CSP allowances can be earned; populating the CSP with allowances vintaged the first compliance year; and using distribution criteria of early reductions and need.

The EPA will apportion the CSP to the States based upon their share of the final, regionwide NO_X CAIR reductions. Similar to the NO_X SIP Call, States may distribute these CAIR NO_X allowances to sources based upon either: (1) A demonstration by the source to the State of NO_X emissions reductions in surplus of any existing NO_X emission control requirements; or (2) a demonstration to the State that the facility has a ''need'' that would affect electricity grid reliability. Sources that wish to receive CAIR CSP allowances based upon a demonstration of surplus emissions reductions will be awarded one CAIR annual NO_X allowance for every ton of NO_X emissions reductions. (Should a State receive more requests for allowances than their share of the CAIR CSP, the State would pro-rate the allowance distribution.) Determination of surplus emissions must use emissions data measured using part 75 monitoring.

The EPA elected to include the CSP in response to several comments noting the benefit of early NO_X reductions and some commenters concerns in complying with the stringent Phase I CAIR NO_X cap. While EPA analysis has shown that sources had sufficient time to install NO_X emission controls, the EPA does believe that it would be appropriate to provide some mechanism to alleviate the concerns of some sources which may have unique issues with complying with the 2009 implementation deadline. In addition to mitigating some of the uncertainty regarding the EPA projections of resources to comply with CAIR, the CAIR CSP also effectively provides incentives for early, surplus NO_X reductions.

The EPA agrees with the comments that advocate allowing sources to earn CAIR annual NO_X allowances only for those reductions that are in surplus of the sources' existing NO_X reduction requirements. By allowing sources in NO_X SIP Call and non-NO_X SIP Call States to demonstrate that their year-round early reductions are truly ''surplus'' and, therefore, deserving of CSP allowances, the EPA is responding to comments that the EPA should allow sources in non-NO_X SIP Call States to receive credit for early reductions. Some commenters advocated crediting sources in the ozone-season NO_X cap and trade program that emitted below the emission rate used to determine the ozone-season budget. The EPA did not accept this recommendation because a source that is allowed to bank NO_X SIP Call allowances into the CAIR ozone-season NO_X program and receive early reduction credit from CAIR's CSP would be essentially ''double-counting'' that emission reduction.

The EPA did not restrict the use of the NO_X allowances awarded from the CSP because several aspects of the CSP already address concerns that too many total credits would be distributed and that they would flood the markets. First, the CSP is a finite pool of NO_X allowances. Second, by requiring sources to reduce one ton of NO_X emissions for every NO_X allowance awarded from the CSP ensures that significant reductions are made prior to the CAIR implementation date.

G. Are There Individual Unit ''Opt-In'' Provisions?

In the SNPR, EPA described a potential approach for allowing certain units to voluntarily participate in, or ''opt-in,'' to the CAIR. Originally, EPA proposed to have no opt-in provision but included language in the SNPR on what a potential opt-in provision may look like. This ''potential'' opt-in provision would have allowed non-EGU boilers and turbines that exhaust to a stack or duct and monitor and report in accordance with part 75 to opt into the CAIR. The opt-in unit would have been required to opt-in for both SO_2 and NO_X. The allocation method for opt-ins assumed a percentage SO_2 reduction from a baseline and for NO_X, allocations were equal to a baseline heat input multiplied by a specified NO_X emissions rate, the same NO_X emissions rate EGUs were subject to in the assumed EGU budgets. Allocations were updated annually and after opting in units would have had to stay in the CAIR for a minimum of 5 years. The EPA received many comments in favor of and very few comments against including an opt-in provision in the final rule. As a result, EPA is including an opt-in provision in this final rule that is based on the approach described in the SNPR but includes several modifications and additions in response to comments as described below. In general, EPA believes there is value to including an opt-in provision but believes that sources that opt-in should be responsible for a certain level of reduction below its baseline because of the additional flexibility provided to that source by opting into a regional trading program and because of the possibility that participation in the CAIR may reduce or eliminate future potential required reductions. Therefore, the following opt-in approach has as its goals to provide more flexibility to the units opting in as well as to potentially provide more cost-effective reductions for the affected EGUs but also to ensure a certain level of reduction from the units opting into the program.

1. Applicability

Some commenters suggested that the opt-in provision not be limited to boilers and turbines but should be open to any unit. The EPA strongly believes that any unit participating in an emissions trading program be subject to accurate and reliable monitoring and reporting requirements. This is the purpose of part 75. The EPA has developed criteria for boilers and turbines to satisfy the requirements of part 75 but has not developed criteria for all non-boilers and turbines and, therefore, cannot be confident their emissions can be monitored with the high degree of accuracy and reliability required by a cap-and-trade program. Continuous Emissions Monitoring Systems or ''CEMS'' are typically what is required by EPA to participate in a cap-and-trade program.

In response to comments received suggesting that non-boilers and turbines be allowed to opt-in, EPA is expanding applicability of the opt-in provision to include, in addition to boilers and turbines, other fossil fuel-fired combustion devices that vent all emissions through a stack and meet monitoring, recordkeeping, and recording requirements of part 75.

2. Allowing Single Pollutant

Some commenters suggested that sources should be allowed to opt-in for only one pollutant instead of requiring the source to opt-in for both SO_2 and NO_X as EPA proposed. These commenters argued that some sources may only emit significant amounts of one of the two regulated pollutants and that it would not make sense to require reductions in both pollutants from such

[136] The 200,000 ton pool includes the 1,503 tons that would be DE and NJ's share. Section V of today's action describes in detail the State-by-State apportionment of the total CSP.

a source. The EPA agrees with this comment and will allow units to opt-in for one pollutant, *i.e.*, NO_X, SO_2, or both. Another commenter suggested that EPA allow non-EGUs subject to the NO_X SIP Call to opt into the CAIR for NO_X only without requiring any reductions in SO_2. This commenter argued that these non-EGUs could simply turn on their SCRs during the non-ozone season and easily achieve significant NO_X reductions. The EPA agrees that the relatively small number of non-EGUs subject to the NO_X SIP Call that have SCRs could achieve significant NO_X reductions by operating their SCRs during the non-ozone season. As stated above, EPA is allowing sources to opt-in for one pollutant and thus non-EGUs subject to the NO_X SIP call may opt-in for NO_X only.

3. Allocation Method for Opt-Ins

In the SNPR, EPA proposed allocating allowances to opt-in units on a yearly basis. The amount of allowances allocated would be calculated by multiplying an emission rate by the lesser of a baseline heat input or the actual heat input monitored at the unit in the prior year.

The baseline heat input would be calculated by using the most recent 3 years of quality-assured part 75 monitoring data. When less than 3 years of quality-assured part 75 monitoring data is available, the heat input would be based on quality-assured part 75 monitoring data from the year before the unit opted in.

For SO_2, EPA proposed that the emission rate used to calculate allocations would be the lesser of, the most stringent State or Federal SO_2 emission rate that applied in the preceding year or the emission rate representing 50 percent of the unit's baseline SO_2 emission rate (in lbs/mmBtu) for the years 2010 through 2014 and 35 percent of the unit's baseline SO_2 emission rate (in lbs/mmBtu) for 2015 and beyond. For NO_X, EPA proposed that the emission rate would be the lower of the unit's baseline emission rate, the most stringent State or Federal NO_X emission limitation that applies to the opt-in unit at any time during the calender year prior to opting into the CAIR Program, or 0.15 lb/mmBtu for the years 2010 through 2014 and 0.11 lbs/mmBtu for the years 2015 and beyond.

In today's final rule, EPA is making a number of changes to its proposed methodology for calculating allocations for opt-in units.

With regards to baseline heat input, EPA is requiring that sources may only use part 75 monitored data for years in which they have maintained at least a 90 percent monitor availability. The EPA is making this change because part 75 contains missing data provisions that require substitution of data when monitors are unavailable. When units have low monitor availability, units are required to report more conservative (*e.g.*, higher) heat input values. This is to provide an incentive to maintain high monitor availability (since under a cap and trade program sources would be required to turn in more allowances if they reported higher emissions). When setting baselines, sources have the opposite incentive, reporting a higher heat input would result in a higher baseline and thus a greater allocation.

With regards to the SO_2 emission rate used to calculate allocations, EPA is requiring that the emission rate used to calculate allocations would be the lesser of, the most stringent State or Federal SO_2 emission rate that applies to the unit in the year that the unit is being allocated for, or the emission rate representing 70 percent of the unit's baseline SO_2 emission rate (in lbs/mmBtu). The EPA is changing the percentage emission reduction upon which allocations are based because some commenters suggested that instead of using percentage emission reduction requirements that are the same as the requirements for EGUs as a basis for allocating to opt-ins, EPA should require emissions reductions based on similar marginal cost of control. The EPA agrees with the basic concept that emissions reductions for opt-ins should be based on similar marginal costs. One commenter submitted results from a study of industrial boiler NO_X and SO_2 control costs that indicated the use of similar marginal cost of control would result in approximately a 30 percent reduction in NO_X and SO_2 by 2010. While the commenter provided limited data to allow EPA to evaluate the commenter's estimates, EPA is using this percentage reduction requirement for the opt-in provision. The same commenter stated that it may be possible to achieve more than a 30 percent reduction in SO_2 and NO_X by 2015 by employing future unspecified technology advances. Because these future technology advances are not specified nor demonstrated, EPA is not requiring more than a 30 percent reduction in SO_2 and NO_X in 2015 and beyond for opt-ins. The EPA is changing the requirement to use the lowest required emission rate for the year preceding the year in which allowances are being allocated to the lowest emission rate for the year in which allowances are being allocated. The EPA is making this change because EPA believes that such data should be available and that this more accurately reflects the intent of the rule to ensure that the source is not being allocated a greater number of allowances than the emissions a source would be allowed to emit under the regulations it is subject to in the year the allocations are being made. The EPA is finalizing parallel provisions with respect to NO_X.

4. Alternative Opt-In Approach

Some commenters suggested that EPA include an alternative approach to opting into the CAIR. This alternative would allow units to opt-in as early as 2009 for NO_X and 2010 for SO_2 and receive allocations at their current emission levels in return for a commitment to make deeper reductions by 2015 than would be required under the general opt-in provision described above. Therefore, for the years 2010 through 2014, the unit would be allocated allowances based on the same heat input used under the general opt-in provision (*e.g.*, the lesser of the baseline heat input or the heat input for the year preceding the year in which allocations are being made) multiplied by an emission rate. This emission rate would be the lower of the emission rate for the year or years before the unit opted in or the most stringent State or Federal emission rate required in the year that the unit opts in. For SO_2 for the years 2015 and beyond, the unit would be allocated allowances based on the same heat input multiplied by an emission rate. This emission rate would be the lower of a 90 percent reduction from the baseline emission rate or the most stringent State or Federal emission rate required in the baseline year. For NO_X, the same methodology would be used, except that the emission rate used for the years 2015 and beyond would be the lower of 0.15 lbs/mmBtu or the most stringent State or Federal emission rate required in the baseline year. The EPA believes the environmental benefit of achieving deeper emissions reductions in the future (2015) from sources that may otherwise not make such deep emissions reductions is worth including in this final rule.

5. Opting Out

In the SNPR, EPA proposed that opt-in units be required to remain in the program a minimum of 5 years after which time they could voluntarily withdraw from the CAIR. Some commenters expressed concern over this proposed approach, arguing that because EGUs affected by the CAIR are not allowed to voluntarily withdraw from the CAIR that opt-in sources should not be allowed to voluntarily withdraw either. The EPA recognizes that opt-in sources such as industrial boilers and turbines tend to be more sensitive to changing market forces than EGUs. As a result, EPA believes it is appropriate to allow opt-in sources who voluntarily participate in an emissions reductions program to be able to end their participation or (''opt-out'') after a specified period of time. As proposed, EPA believes a period of 5 years is appropriate and is finalizing a rule to allow opt-in sources to opt-out after participating in the CAIR for 5 years. This option to opt-out after 5 years does not apply to sources that opt-in under the alternative approach. Sources that opt-in under the alternative approach may not opt-out at any time.

6. Regulatory Relief for Opt-In Units

The CAIR does not offer relief from other regulatory requirements, existing or future, for units that opt-in to the CAIR cap and trade program. Any revision of requirements for other, non-CAIR programs would be done under rulemakings specific to those programs.

As discussed above, EPA is including two different approaches for opt-in units to follow, a general and an alternative approach. The EPA is including both approaches in this final rule in response to comments supportive of including an alternative means and to provide greater flexibility for sources to participate in the CAIR trading program. Opt-in sources may select which approach is more appropriate for their particular situation. An opt-in source may not switch from one approach to the other once in the program. States have the flexibility to choose to include both of these approaches, one of these approaches, or none of them in their SIPs. EPA is not requiring States to include an individual unit opt-in provision because the participation of individual opt-in units is not required to meet the goals of the CAIR. However, States cannot choose to have an individual unit opt-in approach different than what EPA has finalized in this rule and still participate in the inter-State trading program administered by EPA.

H. What Are the Source-Level Emissions Monitoring and Reporting Requirements?

In the NPR, the EPA proposed that sources subject to the CAIR monitor and report NO_X and SO_2 mass emissions in accordance with 40 CFR part 75.

The model trading rules incorporate part 75 monitoring and are being finalized as proposed. The majority of CAIR sources are measuring and reporting SO_2 mass emissions year round under the Acid Rain Program, which requires part 75 monitoring. Most CAIR sources are also reporting NO_X mass emissions year round under the NO_X SIP Call. The CAIR-affected Acid Rain sources that are located in States that are not affected by the NO_X SIP Call currently measure and report NO_X emission rates year round, but do not currently report NO_X mass emissions. These sources will need to modify only their reporting practices in order to comply with the proposed CAIR monitoring and reporting requirements.

Because so many sources are already using part 75 monitoring, there were very few comments on the source-level monitoring requirements in this rulemaking. The comments the EPA received related to sources not currently monitoring under part 75. Commenters suggested that alternative forms of monitoring (*e.g.*, part 60 monitoring) would be appropriate for these sources. The EPA disagrees. Consistent, complete and accurate measurement of emissions ensures that each allowance actually represents one ton of emissions and that one ton of reported emissions from one source is equivalent to one ton of reported emissions from another source. Similarly, such measurement of emissions ensures that each single allowance (or group of SO_2 allowances, depending upon the SO_2 allowance vintage) represents one ton of emissions, regardless of the source for which it is measured and reported. This establishes the integrity of each allowance, which instills confidence in the underlying market mechanisms that are central to providing sources with flexibility in achieving compliance. Part 75 has flexibility relating to the type of fuel and emission levels as well as procedures for petitioning for alternatives. The EPA believes this provides the requested flexibility.

Should a State(s) elect to use the example allocation approach, the EPA would modify the part 75 monitoring and reporting requirements to collect information used in determining the allowance allocations for Combined Heat and Power (CHP) units. More specifically, provisions for the monitoring and reporting of the BTU content of the steam output would be added to the existing requirements. The information on electricity output currently reported under part 75 would not need to be revised to allow States to implement the example allowance allocation approach.

In the SNPR, the EPA proposed continuous measurement of SO_2 and NO_X emissions by all existing affected sources by January 1, 2008 using part 75 certified monitoring methodologies. New sources have separate deadlines based upon the date of commencement of operation, consistent with the Acid Rain Program. These deadlines are finalized as proposed.

I. What Is Different Between CAIR's Annual and Seasonal NO_X Model Cap and Trade Rules?

Today's action finalizes not only the proposed CAIR annual NO_X program and annual SO_2 program, but also a CAIR ozone-season NO_X program. Because the CAIR ozone-season NO_X program is the only ozone-season NO_X cap and trade program that the EPA will administer, NO_X SIP Call States wishing to meet their NO_X SIP Call obligations through an EPA-administered regional NO_X program will also use the CAIR ozone-season rule. The EPA believes that States and affected sources will benefit from having a single, consistent regional NO_X cap and trade program. This section of today's action highlights any key differences between the CAIR ozone-season NO_X model rule and the NO_X SIP Call model rule, as well as the CAIR annual and ozone-season NO_X model rules.

Differences Between the CAIR Ozone-Season NO_X Model Rule and the NO_X SIP Call Model Rule

While the CAIR ozone-season NO_X model rule closely mirrors the NO_X SIP Call rule (as does the other CAIR rules), the EPA has incorporated into the CAIR model rules its experience with implementing trading programs (including seasonal NO_X programs). These modifications include the following.

A. Unrestricted banking: The CAIR ozone-season NO_X model rule will not include any restrictions on the banking of NO_X SIP Call allowances (vintages 2008 and earlier) or CAIR ozone-season NO_X allowances. The NO_X SIP Call rules include ''progressive flow control'' provisions that reduce the value of banked allowances in years where the bank is above a certain percentage of the cap. (See section VIII.E.1 of today's rule for a detailed discussion).

B. Facility level compliance: The CAIR ozone-season NO_X model rule will allow sources to comply with the allowance holding requirements at the facility level. The NO_X SIP Call rules required unit-by-unit level compliance with certain types of allowance accounts providing some flexibility for sources with multiple affected units. (See the June 2004 SNPR, section IV for a detailed discussion).

The EPA believes that these changes improve the programs and that both CAIR and NO_X SIP Call affected sources will benefit from complying with a single, regionwide cap and trade program.

Differences Between the CAIR Ozone-Season and Annual NO_X Model Rules

The CAIR ozone-season and annual NO_X model rules are designed to be identical with the exception of (1) provisions that relate to compliance period and (2) the mechanism for providing incentives for early NO_X reductions. For compliance related provisions, the EPA attempted to maintain as much consistency as possible between the CAIR annual and ozone-season NO_X model rules. For example, reporting schedules remain synchronized (*i.e.*, quarterly reporting) for both of the CAIR NO_X model rules. For the annual and ozone-season NO_X model rules, the EPA did define 12 month and 5 month compliance periods, respectively.

Incentives for early NO_X reductions differ between the CAIR annual and ozone-season programs. For the annual NO_X program, early reductions may be rewarded by States through a CSP. (See section VIII.F.2 of today's action for a detailed discussion.) The CAIR ozone-season NO_X model rule provides incentive for early emissions reductions by allowing the banking of pre-2009 NO_X SIP Call allowances into the CAIR ozone-season program.

J. Are There Additional Changes to Proposed Model Cap and Trade Rules Reflected in the Regulatory Language?

The proposed and final rules are modeled after, and are largely the same as, the NO_X SIP Call model trading rule. Today's final rule includes some relatively minor changes to the model rules' regulatory text that improve the implementability of the rules or clarify aspects of the rules identified by the EPA or commenters. (Note that sections VIII.B through VIII.H of today's action highlight the more significant modifications included in the final model rules).

One example of a relatively minor change is the inclusion of language in the SO_2 model rule that implements the retirement ratio (2.00) used for allowances allocated for 2010 to 2014 and the retirement ratio (2.86) used for allowances allocated for 2015 and later, that clarifies the compliance deduction process and that provides for rounding-up of fractional tons to whole tons of excess emissions. More specifically, the definition of ''CAIR SO_2 allowance'' states that an allowance allocated for 2010 to 2014 authorizes emissions of 0.50 tons of SO_2 and that an allowance allocated for 2015 or later authorizes emissions of 0.35 tons of SO_2—which corresponds with the 2.86 retirement ratio.

Other, less significant modifications were also included in the regulatory text of the final model rules. These include:

C. Units and sources are identified separately for NO_X and SO_2 programs (*e.g.*, CAIR NO_X units, CAIR Nox ozone season units, and CAIR SO_2 units) since States can participate in one, two, or three trading programs;

D. The definition of ''nameplate capacity'' is clarified;

E. The language on closing of general accounts is clarified; and,

F. Process of recordation of CAIR SO_2 allowance allocations and transfers on rolling 30-year periods is added to make it consistent with Acid Rain regulations.

Another example of where today's final model trading rules incorporate relatively minor changes from the proposed model trading rules involves the provisions in the standard requirements concerning liability under the trading programs. The proposed CAIR model NO_X and SO_2 trading rules include, under the standard requirements in § 96.106(f)(1) and (2) and § 96.206(f)(1) and (2), provisions stating that any person who knowingly violates the CAIR NO_X or SO_2 trading programs or knowingly makes a false material statement under the trading programs will be subject to enforcement action under applicable State or Federal law. Similar provisions are included in § 96.6(f)(1) and (2) of the final NO_X SIP Call model trading rule. The final CAIR model NO_X and SO_2 trading rules exclude these provisions for the following reasons. First, the proposed rule provisions are unnecessary because, even in their absence, applicable State or Federal law authorizes enforcement actions and penalties in the case of knowing violations or knowing submission of false statements. Moreover, these proposed rule provisions are incomplete. They do not purport to cover, and have no impact on, liability for violations that are not knowingly committed or false submissions that are not knowingly made. Applicable State and Federal law already authorizes enforcement actions and penalties, under appropriate circumstances, for non-knowing violations or false submissions. Because the proposed rule provisions are unnecessary and incomplete, the final CAIR model NO_X and SO_2 trading rules do not include these provisions. However, the EPA emphasizes that, on their face, the provisions that were proposed, but eliminated in the final rules, in no way limit liability, or the ability of the State or the EPA to take enforcement action, to only knowing violations or knowing false submissions.

IX. Interactions With Other Clean Air Act Requirements

A. How Does This Rule Interact With the NO_X SIP Call?

A majority of States affected by the CAIR are also affected by the NO_X SIP Call. This section addresses the interactions between the two programs.

The EPA proposed that States achieving all of the annual NO_X reductions required by the CAIR from only EGUs would not need to continue to impose seasonal NO_X limitations on EGUs from which they required reductions for purposes of complying with the NO_X SIP Call. Also, EPA proposed that States would have the option of retaining such seasonal NO_X limitations. The EPA also proposed to keep the NO_X SIP Call in place for non-EGUs currently subject to the NO_X SIP Call and to continue working with States to run the NO_X SIP Call Budget Trading Program for all sources that would remain in the program. In response to commenters, EPA is making several modifications to its proposed approach.

States Affected by the CAIR for Ozone and $PM_{2.5}$ Will Be Subject to a Seasonal and an Annual NO_X Limitation

A number of commenters recommended leaving the current NO_X SIP Call ozone season NO_X limitation in place as a way to ensure that ozone season NO_X reductions from EGUs required by the NO_X SIP Call would continue to be achieved. Some commenters argued this would also help non-EGUs currently subject to the NO_X SIP Call by allowing them to continue trading with EGUs in a seasonal NO_X program. Many of the same commenters suggested a dual-season or bifurcated CAIR trading program as a mechanism for maintaining an ozone season NO_X limitation for EGUs under the CAIR. In response to these commenters, EPA is requiring that States subject to the CAIR for $PM_{2.5}$ be subject to an annual limitation and that States subject to the CAIR for ozone be subject to an ozone season limitation. This means that States subject to the CAIR for both $PM_{2.5}$ and ozone are subject to both an annual and an ozone season NO_X limitation. The annual and ozone season NO_X limitations are described in section IV. States subject to the CAIR for ozone only are only subject to an ozone season NO_X limitation. To implement these NO_X limitations, EPA will establish and operate two NO_X trading programs, *i.e.*, a CAIR annual NO_X trading program and a CAIR ozone season NO_X trading program. The CAIR ozone season NO_X trading program will replace the current NO_X SIP Call as discussed in more detail later in this section.

What Will Happen to Non-EGUs Currently in the NO_X SIP Call?

A number of commenters were concerned that the cost of compliance for non-EGUs in the NO_X SIP Call would increase if they were not allowed to continue to trade with EGUs. In response to these commenters, EPA is modifying its proposed approach. The EPA is allowing States affected by the NO_X SIP Call that wish to use EPA's model trading rule to include non-EGUs currently covered by the NO_X SIP Call in the CAIR ozone season NO_X trading program. This will ensure that non-EGUs in the NO_X SIP Call will continue to be able to trade with EGUs as they currently do under the NO_X SIP Call. This will not require States to get additional reductions from non-EGUs. Budgets for these units would remain the same as they are currently under the NO_X SIP Call. States will, however, be required to modify their existing NO_X SIP Call regulations to reflect the replacement of the NO_X SIP Call with the CAIR ozone season NO_X trading program. The EPA will continue to operate the NO_X SIP Call trading program until implementation of the CAIR begins in 2009. The EPA will no longer operate the NO_X SIP Call trading program after the 2008 ozone season and the CAIR ozone season NO_X trading program will replace the NO_X SIP Call trading program. If States affected by the NO_X SIP Call do not wish to use EPA's CAIR ozone season NO_X trading program to achieve reductions from non-EGU boilers and turbines required by the NO_X SIP Call, they would be required to submit a SIP Revision deleting the requirements related to non-EGU participation in the NO_X SIP Call Budget Trading Program and replacing them with new requirements that achieve the same level of reduction.

Compliance With the NO_X SIP Call for States That Are Subject to Both the CAIR Ozone Season NO_X Reduction Requirements and the NO_X SIP Call

If the only changes a State makes with respect to its NO_X SIP Call regulations are: (1) To bring non-EGUs that are currently participating in the NO_X SIP Call Budget Trading Program into the CAIR ozone season program using the same non-EGU budget and applicability requirements that are in their existing NO_X SIP Call Budget Trading Program; and (2) to achieve all of the emissions reductions required under the CAIR from EGUs by participating in the CAIR ozone season NO_X trading program, EPA will find that the State continues to meet the requirements of the NO_X SIP Call.

If the only changes a State makes with respect to its NO_X SIP Call regulations are not those described above, see section VII for a discussion of how the State would satisfy its NO_X SIP Call obligations.

States in the NO_X SIP Call But Not Affected by the CAIR (Rhode Island)

Rhode Island is the only State in the NO_X SIP Call that is not affected by the CAIR. To continue meeting its NO_X SIP Call obligations in 2009 and beyond, Rhode Island will have two choices. It may either modify its NO_X SIP Call trading rule to conform to the new CAIR ozone season NO_X trading rule if it wishes to allow its sources to continue to participate in an interstate NO_X trading program run by EPA or, it will need to develop an alternative method for obtaining the required NO_X SIP Call reductions. In either case, Rhode Island must continue to meet the budget requirements of the existing NO_X SIP Call.

Use of Banked SIP Call Allowances in the CAIR Program

As explained earlier in today's final rule, banked allowances from the NO_X SIP Call may be used in the CAIR ozone season NO_X trading program.

Other Comments and EPA's Responses

One commenter wrote that because attainment demonstrations for early action compacts were made based on having EGUs and non-EGUs together in the NO_X SIP Call, EPA could not allow EGUs to leave the NO_X SIP Call and still have valid early action compacts (EACs). As discussed above, EPA is allowing States to keep EGUs and non-EGUs in the NO_X SIP Call together in one ozone season program (CAIR ozone season trading program). The NO_X reductions required by the CAIR ozone season trading program are slightly more stringent than the reductions required by the NO_X SIP Call. As a result, the attainment demonstrations for EACs would remain valid under the CAIR. Having said that, the EAC program will have ended (April 2008) before the CAIR rule is implemented. Thus, the compacts will no longer be applicable when the CAIR takes effect.

Another commenter proposed to have non-EGUs under the NO_X SIP Call subject to an annual NO_X cap similar to EGUs under the CAIR so that non-EGUs could continue to trade with EGUs. By adopting a CAIR ozone season trading program that includes non-EGUs covered by the NO_X SIP Call, non-EGUs will be able to continue to trade with EGUs.

B. How Does This Rule Interact With the Acid Rain Program?

As EPA developed this regulatory action, much consideration was given to interactions between the existing title IV Acid Rain Program and today's action designed to achieve significant reductions in SO_2 emissions beyond title IV. Requiring sources to reduce emissions beyond what title IV mandates has both environmental and economic implications for the existing title IV SO_2 cap and trade program. In the absence of an approach for taking account of the title IV program, a new program (*i.e.*, the CAIR) that imposes a significantly tighter cap on SO_2 emissions for a region encompassing most of the sources and most of the SO_2 emissions covered by title IV would likely result in a significant excess in the supply of title IV allowances, a collapse of the price of title IV allowances, disruption of operation of the title IV allowance market and the title IV SO_2 cap and trade system, and the potential for increased SO_2 emissions. The potential for increased emissions would exist in the entire country for the years before the CAIR implementation deadline and would continue after implementation for States not covered by the CAIR. These negative impacts, particularly those on the operation of the title IV cap and trade system, would undermine the efficacy of the title IV program and could erode confidence in cap and trade programs in general.

Title IV has successfully reduced emissions of SO_2 using the cap and trade approach, eliminating millions of tons of SO_2 from the environment and encouraging billions of dollars of investments by companies in pollution controls to enable the sale of allowances reflecting excess emissions reductions and in allowance purchases for compliance. In view of these already achieved reductions and existing investments under title IV, the likelihood of disruption of the allowance market and the title IV cap and trade system, and the potential for SO_2 emission increases, it is necessary to consider ways to preserve the environmental benefits achieved under title IV and maintain the integrity of the market for title IV allowances and the title IV cap and trade system. The EPA maintains that it is appropriate to provide States the opportunity to achieve the SO_2 emission reductions required under today's action by building on, and avoiding undermining, this existing, successful program.

The EPA has developed, in the model SO_2 cap and trade rule, an approach to build on and coordinate with the title IV SO_2 program to ensure that the required reductions under today's action are achieved while preserving the efficacy of the title IV program. The EPA's approach provides States the opportunity to impose more stringent control requirements for EGUs' SO_2 emissions than under title IV through an EPA-administered cap and trade program that requires the use of title IV allowances for compliance at a ratio of 2 allowances per ton of emissions for allowances allocated for 2010 through 2014 and 2.86 allowances per ton of emissions for allowances allocated for 2015 or thereafter. (The program also allows the use of banked title IV allowances allocated for years before 2010 to be used at a ratio of 1 allowance per ton of emissions.) Title IV allowances continue to be freely transferable among sources covered by the Acid Rain Program and sources covered by the model SO_2 cap and trade program under CAIR. However, each title IV allowance used to comply with a source's allowance-holding requirement in the CAIR model SO_2 cap and trade program is removed from the source's allowance tracking system account and cannot be used again for compliance, either in the CAIR model SO_2 cap and trade program or the Acid Rain Program.

In addition, as discussed above, if a State wants to achieve the SO_2 emissions reductions required by today's action through more stringent EGU emission limitations only but without using the model cap and trade program, then EPA is requiring that the State include in its SIP a mechanism for retiring the excess title IV allowances that will result from imposition of these more stringent EGU requirements. In this case, the State must retire an amount of title IV allowances equal to the total amount of title IV allowances allocated to the units in the State minus the amount of title IV allowances equivalent to the tonnage cap set by the State on SO_2 emissions by EGUs, and the State can choose what retirement mechanism to use.

Further, as discussed above, if a State wants to meet the SO_2 emissions reductions requirement in today's action through reductions by both EGUs and non-EGUs, then EPA is also requiring the State's SIP to include a mechanism for retiring excess title IV allowances. In that case, the amount of title IV allowances that must be retired equals the total amount of title IV allowances allocated to the units in the State minus the amount of title IV allowances equivalent to the tonnage cap set by the State on EGU SO_2 emissions, and the State can choose what retirement mechanism to use.

Finally, as discussed above, if the State wants to achieve the SO_2 emissions reductions requirement in today's action through reductions by non-EGUs only, then EPA is not imposing any requirement to retire title IV allowances.

1. Legal Authority for Using Title IV Allowances in CAIR Model SO_2 Cap and Trade Program

The EPA maintains that it has the authority to approve and administer, if requested by a State in the SIP submitted in response to today's action, the new CAIR model SO_2 cap and trade program meeting the SO_2 emission reduction requirement in today's action that requires use of title IV allowances to comply with the more stringent allowance-holding requirement of the new program and retirement under the CAIR SO_2 cap and trade program and the Acid Rain Program of title IV allowances used for such compliance. Some commenters claim that EPA's establishment of such a cap and trade program using title IV allowances that sources must hold generally at a ratio of greater than one allowance per ton of SO_2 emissions is contrary to title IV. Most of these commenters prefer the approach of allowing States to use a new EPA-administered cap and trade program to meet lawful emission reduction requirements under title I and of allowing (but not requiring) sources to use title IV allowances in the new program. However, these commenters argue that title IV prohibits requiring sources to use title IV allowances in such a program, whether at the same tonnage authorization (*i.e.*, one allowance per ton of emissions) established in title IV or at a different tonnage authorization. Other commenters state that title IV does not bar EPA from establishing a new cap and trade program that requires the use of title IV allowances.

The EPA maintains that it has the authority under section 110(a)(2)(D) and title IV to establish a new cap and trade program requiring the use of title IV allowances at a different tonnage authorization than under the Acid Rain Program and the retirement of such allowances for purposes of both programs. First, as discussed in section V above, EPA has the authority under section 110(a)(2)(D) to establish a new SO_2 cap and trade program, administered by EPA if requested in a State's SIP, to prohibit emissions that contribute significantly to nonattainment, or interfere with maintenance, of the $PM_{2.5}$ NAAQS. Further, EPA notes that under section 402(3), a title IV allowance is:

> An authorization, allocated to an affected unit by the Administrator under this title [IV], to emit, during or after a specified calendar year, one ton of sulfur dioxide. 42 U.S.C. 7651(a)(3).

However, section 403(f) states that:

> An allowance allocated under this title is a limited authorization to emit sulfur dioxide in accordance with the provision of this title [IV]. Such allowance does not constitute a property right. Nothing in this title [IV] or in any other provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. Nothing in this section relating to allowances shall be construed as affecting the application of, or compliance with, any other provision of this Act to an affected unit or source, including the provisions related to applicable National Ambient Air Quality Standards and State implementation plans. 42 U.S.C. 7651b(f).

The EPA interprets the reference in section 403(f) to the authority of the "United States" to terminate or limit the authorization otherwise provided by a title IV allowance to mean that EPA (acting in accordance with its authority under other provisions of the CAA), as well as Congress, has such authority.[137]

[137] The EPA's interpretation is based on the language of section 403(f) and the legislative history of the provision. The language in CAA section 403(f) contrasts with language that was in section 503(f) of the House bill—but was excluded from the final version of the CAA Amendments of 1990—referring to the authority of the "United States" to terminate or limit such authorization "by Act of Congress" and stating that "[a]llowances under this title may not be extinguished by the Administrator." U.S. Senate Committee on Environment and Public Works, *A Legislative History of The Clean Air Act Amendments of 1990* (*Legis. Hist. of CAAA*), S. Prt. 38, 103d Cong., 1st Sess., Vol. II at 2224 (Nov. 1993). Further, unlike CAA section 403(f), the House bill did not state that an allowance did not constitute a property right. Section 403(f) of the Senate bill that was considered, along with the House bill, in conference committee had language different than both CAA section 403(f) and the House bill and stated that "allowances may be limited, revoked or otherwise modified in accordance with the provisions of this title or other authority of the Administrator" and that an allowance "does not constitute a property right." *Legis. Hist. of CAAA,* Vol. III at 4598. While the scope of the reference to the "United States" in CAA section 403(f) is not clear, EPA maintains that the term is clearly broad enough to include the Administrator. Moreover, even if the term were considered ambiguous with regard to the Administrator, EPA believes that interpreting the term to include the Administrator is reasonable. Specifically, EPA maintains that, by eliminating the explicit House bill language that required Congressional action and including the general reference to the "United States" and the "not a property right" language, CAA section 403(f)

Continued

Therefore, EPA maintains that it has the authority to establish a new cap and trade program in accordance with section 110(a)(2)(D) that requires: the holding of title IV allowances under a more limited authorization (*i.e.*, 2 or 2.86 allowances per ton of emissions) by sources in States participating in the new program; and the termination of the authorization through retirement under the new program and the Acid Rain Program of those title IV allowances used to meet the allowance-holding requirement of the new program.

Commenters' Arguments Based on Title IV

The commenters claiming that EPA is barred by title IV from requiring use of title IV allowances at a reduced tonnage authorization in a new cap and trade program rely on the above-noted provision in section 402(3) stating that an allowance is an authorization to emit one ton of SO_2. However, this provision does not bar EPA from requiring either: use of title IV allowances in a new cap and trade program under a different title of the CAA at a reduced tonnage authorization; or retirement in this new program and the Acid Rain Program of allowances used in this manner.

At the outset, it should be noted that the CAIR model SO_2 cap and trade program does not change the tonnage authorization of individual title IV allowances for purposes of the Acid Rain Program until such an allowance is used to meet the allowance-holding requirement of the CAIR SO_2 program. The authorization provided by each title IV allowance for a source to emit one ton of SO_2 emissions, as well as the requirement that each source hold title IV allowances covering annual SO_2 emissions, continue to be in effect in the Acid Rain Program whether or not the source is also covered by the CAIR SO_2 program. In fact, the Acid Rain Program regulations continue to reflect both this tonnage authorization and this allowance-holding requirement.[138] See final revisions to 40 CFR § 73.35 adopted in today's action. Moreover, the CAIR model SO_2 cap and trade rule coordinates the determinations—made by EPA for sources subject to both title IV and the CAIR—of compliance with the title IV and CAIR allowance-holding requirements so that such determinations are made in a multi-step, end-of-year process of comparing allowances held and emissions. First, EPA determines whether the source holds sufficient title IV allowances to comply with the one-allowance-per-ton-of-emissions requirement in the Acid Rain Program as provided in § 73.35; and subsequently EPA determines whether the source holds the additional title IV allowances that, when added to those held for Acid Rain Program compliance, are sufficient to meet the CAIR allowance-holding requirement. Violations of the Acid Rain allowance-holding requirement will result in imposition of the penalty for excess emissions (*i.e.*, the one-allowance offset plus $2,000 (inflation-adjusted) per ton of excess emissions) under CAA section 411 and §§ 73.35(d) and 77.4. *See* final § 96.254(b)(1) adopted in today's action. Thus, the Acid Rain allowance-holding requirement continues as a separate requirement and reflects the one-allowance-per-ton-of-emissions authorization under section 402(3).[139]

In contrast with the one-allowance-per-ton-of-emissions requirement under the Acid Rain Program, the CAIR SO_2 cap and trade program requires each source generally to hold 2 or 2.86 Acid Rain allowances for each ton of SO_2 emissions. Contrary to the commenters' claim, this CAIR allowance-holding requirement is not barred by the definition of the term ''allowance'' in section 402(3). While section 402(3) defines the term ''allowance'' as an authorization to emit one ton of SO_2, this provision expressly applies the definition to the term ''[a]s used in this title [IV]'' and therefore does not apply to the treatment of title IV allowances in a different program under a different title of the CAA. Moreover, as noted above, section 403(f) allows EPA to limit (or terminate) the authorization to emit that an allowance otherwise provides under section 402(3). Consequently, the allowance definition in section 402(3) does not bar the treatment of a title IV allowance as authorizing less than one ton of SO_2 emissions under the CAIR SO_2 cap and trade program established under title I.[140]

Once a title IV allowance is used to meet the more stringent allowance-holding requirement in the CAIR SO_2 program, that allowance is deducted from the source's allowance tracking system account and cannot be used again, either in the CAIR SO_2 program or the Acid Rain Program. As noted above, EPA has the authority under section 403(f) to require this termination of such a title IV allowance's tonnage authorization for purposes of the Acid Rain Program.

In addition to referencing section 402(3) to support claims that EPA is barred from adopting the CAIR model cap and trade program provisions on the use of title IV allowances, the commenters rely on other title IV provisions that they characterize as setting a ''title IV cap'' on SO_2 emissions. Stating that the requirement to use title IV allowances in the CAIR model SO_2 cap and trade program has the effect of reducing the ''title IV cap,'' these commenters indicate, with little explanation, that such requirement is unlawful. In mentioning the title IV cap, the commenters are apparently referring to the fact that section 403(a)(1) (requiring allowance allocations resulting in emissions not exceeding 8.90 million tons of SO_2) and section 405(a)(3) (requiring additional allocations of 50,000 allowances) require EPA to allocate annually, starting in 2010, a total amount of allowances authorizing no more than 8.95 million tons of SO_2 emissions. The commenters' argument about how the CAIR model SO_2 cap and trade program effectively reduces the ''title IV cap'' appears to be that elimination of the ability to use, in the Acid Rain Program, title IV allowances that will be used for compliance in the CAIR model SO_2 cap and trade program has the effect of reducing the annual 8.95 million ton cap on SO_2 emissions. This effective reduction of the ''title IV cap'' seems to occur when title IV allowances are used in the CAIR SO_2 trading program with a reduced tonnage authorization so that more title IV allowances are deducted per ton of emissions than would be deducted for compliance with the Acid

essentially adopted the Senate's approach and allows the United States—either through Congressional or administrative (*i.e.*, EPA) action—to terminate or limit the allowance authorization. *See Legis. Hist. of CAAA,* Vol. I at 754, 1034, and 1084 (Oct. 27, 2000 floor statements of Sen. Symms, Sen. Baucus, and Sen. McClure indicating EPA has authority to take such action); *but see* Cong. Rec. at E 3672 (Nov. 1, 2000)(extension of remarks of Cong. Oxley indicating that only Congress has such authority).

[138] As discussed below, today's action revises the Acid Rain Program regulations to provide for source-based, instead of unit-based, compliance with the allowance-holding requirement. These revisions are adopted for reasons independent of the adoption of the CAIR model SO_2 cap and trade program, as well as to facilitate the coordination of these two SO_2 trading programs.

[139] The commenters' assertion that the sources in a State that does not participate in the CAIR SO_2 cap and trade program will be cut off from the Acid Rain cap and trade program is incorrect on its face. Such a source will continue to be subject to the allowance-holding requirement and the compliance process in § 73.35 and will not be subject to the allowance-holding requirement and the compliance process in the CAIR model SO_2 cap and trade rule.

[140] The commenters also seem to argue that the allowance definition itself bars EPA from requiring use of Acid Rain allowances in the CAIR SO_2 trading program even on a one-allowance-per-ton-of-emissions basis. However, as noted above, the definition is silent on whether title IV allowances may or may not be used outside the Acid Rain Program.

Rain Program.[141] The commenters claim that such a reduction in the 8.95 million ton cap is contrary to title IV.

In asserting an overarching principle that EPA is barred from adopting any requirement that would have the effect of reducing the 8.95 million ton cap under title IV, the commenters do not point to any specific statutory provision in support. The EPA maintains that not only are there no such supporting provisions, but also certain title IV provisions contradict this purported principle. Specifically, while sections 403 and 405 require annual allowance allocations authorizing no more than 8.95 million tons of emissions, section 403(f) provides, as noted above, that EPA may terminate or limit the one-allowance-per-ton-of-emissions authorization for a title IV allowance.[142] Because any termination or limitation of the tonnage authorization provided by a title IV allowance for purposes of the Acid Rain Program would have the effect of reducing the total tonnage of emissions allowed by the allowance allocations (i.e., the 8.95 million ton cap) under sections 403 and 405, the commenters' claim that EPA is barred from adopting any provision that has such an effect is wrong on its face.

Commenters' Argument Based on Clean Air Markets Group Case

The commenters also state that the CAIR model SO_2 cap and trade program is unlawful under the court's holding in *Clean Air Markets Group* v. Pataki, 338 F.3d 82 (2d Cir. 2003). According to the commenters, the required use of title IV allowances in the CAIR SO_2 program constitutes an unlawful interference with the operation of the interstate title IV SO_2 trading program, presumably similar to the unlawful interference found by the court in *Clean Air Markets Group.* However, the commenters provide little explanation of how such use of title IV allowances (with or without a reduced tonnage authorization) purportedly interferes with interstate operation of the Acid Rain Program and how the holding in *Clean Air Markets Group* applies to the CAIR SO_2 program.

In *Clean Air Markets Group,* the Court reviewed a State law that imposed a monetary assessment on any title IV allowance sold by a New York utility to a utility in any of 14 specified States or subsequently transferred to such a utility, with the assessment equaling the proceeds received in the allowance sale. The law also required that each allowance sold include a covenant barring subsequent transfer of the allowance to a utility in any of those States. The Court held that the State law was pre-empted by title IV because the State law impermissibly interfered with the method chosen by Congress in title IV to reduce utilities' SO_2 emissions, *i.e.*, the opportunity for nationwide trading of title IV allowances. *Id.* at 87–88. In particular, the Court found that the assessment of 100 percent of sale proceeds ''effectively bans'' sales of any allowance by New York utilities to utilities in the specified States and that the restrictive covenant ''indisputedly decreases'' the value of the allowances. *Id.* at 88.

The EPA maintains that today's action is distinguishable from the facts and holding in *Clean Air Markets Group.* In particular, EPA believes that the exercise of its explicit authority under section 403(f) to limit the tonnage authorization of a title IV allowance in the CAIR SO_2 cap and trade program and to terminate the tonnage authorization in the Acid Rain Program once the allowance is used in the CAIR SO_2 program is consistent with—and necessary to preserve—the operation of the Acid Rain Program. Therefore, EPA concludes that its approach of limiting and terminating of the tonnage authorization of title IV allowances does not impermissibly interfere with the interstate operation of the Acid Rain Program and is reasonable.

Unlike the circumstances in *Clean Air Markets Group,* under EPA's approach in today's action, each title IV allowance is freely transferable nationwide unless and until a source uses the allowance to meet the allowance-holding requirements of the CAIR SO_2 program, at which time the allowance is deducted from the source's allowance tracking system account and retired for purposes of both the CAIR SO_2 program and the Acid Rain Program. Further, EPA expects that the ability to use title IV allowances to meet the more stringent emission limitation under the CAIR SO_2 program to maintain or increase (not decrease) the value of each title IV allowance, until the allowance is used to meet the CAIR SO_2 program allowance-holding requirement and is retired.

Of course, this retirement of title IV allowances once they are used to meet the CAIR allowance-holding requirement means that they cannot thereafter be transferred to any person or be used again, *e.g.*, to meet the Acid Rain Program allowance-holding requirement. As noted by the Court in *Clean Air Markets Group,* section 403(b) provides that title IV allowances ''may be transferred among designated representatives of owners or operators of affected sources under [title IV] and any other person who holds such allowances, as provided by the allowance system regulations'' promulgated by EPA.[143] 42 U.S.C. 7651b(b). Moreover, section 403(d)(1) requires that the allowance system regulations ''specify all necessary procedures and requirements for an orderly and competitive functioning of the allowance system.'' 42 U.S.C. 7651b(d). In the context of these statutory requirements, EPA maintains that, on balance, the retirement of title IV allowances used for compliance in the CAIR model SO_2 cap and trade program does not constitute impermissible interference with the interstate operation of the Acid Rain Program, but rather is consistent with, and necessary to preserve, the operation of the Acid Rain Program.

As noted above, the imposition of an SO_2 emission limitation (such as in today's action) that is significantly more stringent than the one under title IV and covers most of the sources and emissions covered by title IV—but without addressing the impact on the Acid Rain Program—would likely have several adverse consequences. These adverse consequences would be: A significant excess of title IV allowances; a collapse of the price of title IV allowances; disruption of the title IV allowance market and the title IV SO_2 cap and trade system; and potential SO_2 emission increases, particularly in States outside the CAIR SO_2 region. The EPA modeling indicates that, in 2010, EGU SO_2 emissions in States not affected by the CAIR SO_2 program would increase by about 260,000 tons (or about 29 percent of the approximately 0.9 million tons of SO_2 emissions projected for the non-CAIR SO_2 region in 2010) in the absence of an approach for addressing the impact of the CAIR SO_2 program on title IV. This

[141] Similarly, to the extent title IV allowances are used in the CAIR SO_2 trading program by non-Acid Rain sources, the ''title IV cap'' seems to be effectively reduced because more allowances are used in the CAIR SO_2 trading program and effectively removed from use in the Acid Rain Program.

[142] In light of this provision, the statement in the NPR (particularly as it is interpreted by the commenters) that EPA lacks authority to tighten the requirements of title IV (69 FR 4618, col. 1) is overly broad and is not repeated or adopted in today's preamble.

[143] While section 403(b) (as well as section 403(d)) refer specifically to the allowance system regulations required to be promulgated by the EPA Administrator within 18 months of November 15, 1990 (the enactment date of the CAA), the EPA Administrator has authority under section 301 to amend such regulations ''as necessary to carry out his functions under [the CAA].'' 42 U.S.C. 7601.

is because, with the imposition of the more stringent CAIR SO_2 emission limitation in the CAIR SO_2 region, this more stringent limitation becomes the binding limitation for sources in that region. These CAIR SO_2 sources must comply with, and cannot use title IV allowances to exceed, the CAIR SO_2 emission limitation. Consequently, the portion of the title IV allowances that equals the difference between the CAIR and the title IV emission limitations is excess and would be available for use only by Acid Rain sources that are outside the CAIR SO_2 region.

This excess amount of title IV allowances is potentially very significant. Today's action requires that the States in the CAIR SO_2 region achieve an amount of SO_2 emission reductions in 2010 and 2015 equal to 50 percent and 65 percent, respectively, of the amount of title IV allowances (about 7.3 million allowances out of the total nationwide allocation of 8.95 million allowances) allocated to the units in the CAIR SO_2 region. If the States achieve all the required CAIR SO_2 reductions through emission reductions by EGUs (which are largely the same units that are subject to the Acid Rain Program) and if EGUs held only one title IV allowance for each ton of SO_2 emissions as required in the Acid Rain Program, the amount of surplus allowances allocated to the States in the CAIR SO_2 region would be about 3.65 million allowances and 4.75 million allowances, respectively in 2010 and 2015.[144] Moreover, the vast majority of EGUs nationwide (about 90 percent) and of EGU SO_2 emissions nationwide (about 90 percent) are covered by the CAIR SO_2 program. The net result would be a large surplus of title IV allowances that would not be usable in the CAIR SO_2 region and would be usable only by the small subset of EGUs (about 10 percent) located in non-CAIR SO_2 region States. Looking at the nation as a whole (both CAIR and non-CAIR SO_2 States) in 2010, there would be total allocations in the Acid Rain Program of 8.95 million title IV allowances but, according to EPA modeling and analysis of the CAIR without a requirement to retire surplus title IV allowances, total projected SO_2 emissions for EGUs of only about 4.8 million tons.[145] Based on the principles of supply and demand, EPA concludes that, with the amount of allowances allocated nation wide exceeding SO_2 emissions for EGUs nationwide in 2010 by about 86 percent (*i.e.*, 8.95 million allowances minus 4.8 million tons divided by 4.8 million tons), the value of title IV allowances would fall to zero, and all but 260,000 of the surplus allowances would have no market and so, as a practical matter, would not be transferable.

The EPA notes that this effect on allowances would occur no matter how the State implements the more stringent SO_2 emission limitation required under the CAIR, *e.g.*, whether implementation is through a new cap and trade program (like in the model rule) or through a fixed (command and control) tonnage emission limit imposed on each individual source. Consequently, the alternatives faced by EPA are either: (1) To establish a CAIR model cap and trade program (or allow States to use another means of achieving CAIR SO_2 emissions reductions) that does not retire the 3.65 million surplus allowances and that results in the devaluation of all title IV allowances to zero and the effective non-transferability of all but 260,000 of the 3.65 million surplus allowances in 2010; or, as provided in today's action, (2) to adopt a CAIR SO_2 model cap and trade program (or another means of achieving reductions) that retires the 3.65 million surplus allowances and that results in the non-transferability of the entire 3.65 million surplus of title IV allowances and ensures the remaining, unused title IV allowances have market value. Thus, with regard to the impact on the transferability of title IV allowances, EPA's decision to adopt the second alternative of retiring the surplus allowances adversely affects the transferability of only a relatively small amount (260,000 out of 8.95 million per year) of allowances, as compared to the amount of allowances whose transferability would be adversely affected under the first alternative.

Moreover, with the total collapse of the title IV allowance price in the Acid Rain Program, the nationwide cap and trade system under title IV—which would be the binding cap and trade system only for sources in the States outside the CAIR SO_2 region—would lose all efficacy. The title IV cap and trade system operates by: Making owners of sources pay for the authorization to emit SO_2 by surrendering, to EPA, allowances that have a market value; and by allowing owners (*e.g.*, those who choose to reduce emissions) to sell unused allowances. Whether the sources' allowances were originally allocated to the sources or were purchased, the owners must decide the extent to which it is more efficient to give up the market value of such allowances or to reduce emissions. If title IV allowances were to have no market value, the title IV cap and trade system would no longer affect the choice of whether to emit or to reduce emissions.[146]

The EPA maintains that such a result is contrary to Congressional intent. The purposes of title IV include not only reductions of annual SO_2 emissions from 1980 levels, but also the encouragement of ''energy conservation, use of renewable and clean alternative technologies, and pollution prevention as a long-range strategy, consistent with the provisions of this title, for reducing air pollution and other adverse impacts of energy production and use.'' 42 U.S.C. 7651(b). Reflecting these purposes, Congress required EPA to promulgate allowance system regulations for the Acid Rain Program that would promote ''an orderly and competitive functioning of the allowance system.'' 42 U.S.C. 7651b(d)(1). *See* Sen. Rep. No. 101–228, 101st Cong., 1st Sess. at 320 (explaining that ''the allowance system is intended to maximize the economic efficiency of the program both to minimize costs and to create incentives for aggressive and innovative efforts to control pollution''). As discussed above, if title IV allowances were to have no market value, the cap and trade system under title IV would no longer affect owners' decisions on whether to emit or to control emissions and so would no longer provide encouragement (*e.g.*,

[144] The surpluses for 2010 and 2015 respectively are calculated as: 7.3 million allowances minus ((100 percent minus the percentage reduction requirement for the year) times 7.3 million allowances).

[145] The 4.8 million ton figure is the sum of: 3.65 million tons of emissions (equal to the tonnage equivalent of the allowance allocations in the CAIR SO_2 region); plus about 0.9 million tons of emissions in the non-CAIR SO_2 region with the retirement of surplus title IV allowances; plus 260,000 tons of increased non-CAIR SO_2 region emissions if the surplus title IV allowances are not retired.

[146] *See* Sen. Rep. No. 101–228, 101st Cong., 1st Sess. at 324 (Dec. 20, 1989) (stating that ''[a]llowances are intended to function like a currency that is sufficiently valuable to stimulate efforts to acquire it through innovative and aggressive efforts to reduce emissions more than required'' and that, in the event of ''inflation in the currency,'' the incentives to ''reduce pollution * * * will be seriously weakened.'' In the instant case, without a requirement to retire excess title IV allowances, the currency would be inflated to a value of zero. *See also Legis. Hist. of CAAA*, Vol. I at 1033 (Oct. 27, 1990 floor statement of Sen. Baucus explaining that ''[s]ince units can gain cash revenues from the sale of allowances they do not use, they will have a financial incentive both to make greater-than-required reductions and/or reductions earlier than required'' and that ''incentives created by the allowance market should stimulate innovations in the technologies and strategies used to reduce emissions'' including energy efficiency).

incentives for innovation) for avoidance or reduction of SO_2 emissions.[147]

In addition, EPA is concerned that such disruption of the title IV allowance market and the title IV SO_2 cap and trade system would significantly erode confidence in cap and trade programs in general and the CAIR model cap and trade programs in particular. As noted above, under the Acid Rain Program, companies have made billions of dollars of investments in emission controls in order to be able to sell excess title IV allowances and in purchasing title IV allowances for future compliance (*e.g.*, under annual, 1-day allowance auctions held by EPA, one as recently as March 22, 2004 when title IV allowances were purchased for about $50 million). While in a market-based program like the Acid Rain Program, investments are necessarily subject to the vagaries of the market, EPA believes that it should try, to the extent possible consistent with statutory requirements, to avoid taking administrative actions that would cause such extensive disruption of the Acid Rain Program. Allowing such disruption to occur could significantly reduce the willingness of owners of sources in new cap and trade programs to invest in measures that would result in excess allowances for sale or to purchase allowances for compliance. To the extent owners would ignore the allowance-trading option and simply control emissions to the level equal to their source's allocations, this would obviate the incentives for innovation, and hamper realization of the potential for cost savings, that would otherwise be provided by new cap and trade programs (such as the CAIR model cap and trade programs).

Finally, as noted above, such disruption of the Acid Rain Program would potentially result in significantly increased SO_2 emissions (about 29 percent in 2010) in States covered by the Acid Rain Program but outside the CAIR SO_2 region.[148] This would have the effect of reversing, at least in part, the beneficial effect that the Acid Rain Program has had on SO_2 emissions in those States, even though the overall goal of nationwide SO_2 emissions reductions would still be met. *See* 42 U.S.C. (a)(1) (Congressional finding that ''the presence of acidic compounds and their precursors in the atmosphere and in deposition from the atmosphere represents a threat to natural resources, ecosystems, materials, visibility, and public health'').

In light of these considerations,[149] EPA concludes, on balance, that structuring the CAIR model SO_2 cap and trade program in a way that avoids such extensive disruption of the Acid Rain Program (*i.e.*, by requiring retirement from the Acid Rain Program of title IV allowances used for compliance in the CAIR SO_2 program) does not constitute impermissible interference with the interstate operation of the Acid Rain Program. Rather, this approach in the model SO_2 cap and trade rule is consistent with, and preserves, such operation—while providing States a tool for imposing the more stringent SO_2 emission limitations required under title I—and is a reasonable exercise of EPA's authority under section 403(f) to terminate or limit the tonnage authorization of title IV allowances.

2. Legal Authority for Requiring Retirement of Excess Title IV Allowances if State Does Not Use CAIR Model SO_2 Cap and Trade Program

As discussed above, a State has the additional options of achieving the SO_2 emissions reductions required by today's actions through: EGU emission reductions only but without using the model SO_2 cap and trade rule; some EGU and some non-EGU emissions reductions; or non-EGU reductions only. The requirement to retire excess title IV allowances applies only in the first and second of these three additional options. The State must retire an amount of title IV allowances equal to the total amount of title IV allowances allocated to units in the State minus the amount of allowances equivalent to the tonnage cap set by the State on EGUs' SO_2 emissions and can choose what mechanism to use to achieve such retirement. The EPA has the authority to require that the State include in its SIP a mechanism for retiring the excess title IV allowances that will result under these two options.

As discussed above, EPA has the authority under section 403(f) to terminate or limit the authorization to emit otherwise provided by a title IV allowance. Specifically, EPA has the authority to: require that any EGU SO_2 emission reduction program, chosen by a State to meet (in full or in part) the requirements of section 110(a)(2)(D), include provisions for retiring excess title IV allowances resulting from the implementation of the more stringent emission reduction requirement under the State program; and to require that such retired title IV allowances cannot be used in the Acid Rain Program. As discussed above, the commenters' claims that such a retirement requirement is barred by title IV (relying on, *e.g.*, the section 402(3) definition of ''allowance'' and on the ''title IV cap'') lack merit. Also, for the reasons discussed above, the retirement requirement is not unlawful under *Clean Air Markets Group* and is a reasonable exercise of EPA's authority under section 403(f) to terminate or limit the tonnage authorization of title IV allowances.

Some commenters also claim that the retirement requirement unlawfully constrains the States' authority to determine in the first instance the control measures to use in meeting emission reduction requirements necessary to comply with section 110(a)(2)(D). According to the commenters, since only EGUs are subject to title IV, the requirement to retire title IV allowances is in effect a mandate that the State control EGU emissions.

However, EPA is imposing the requirement for a State mechanism to retire title IV allowances only if the State decides in the first instance to require any EGU SO_2 emissions reductions to meet the emission reduction requirements under today's action. A State that decides not to require any EGU SO_2 emissions reductions for this purpose is not required to retire title IV allowances. Further, the amount of the required allowance retirement is limited to the amount of EGU SO_2 emissions reductions that the State decides in the first instance to require from EGUs (*i.e.*, the total title IV allowance allocations in the State minus the tonnage amount of the cap set by the State for EGUs' SO_2 emissions). In short, the allowance retirement requirement echoes the State's decision in the first instance concerning the amount of SO_2 emissions reductions to require from EGUs in the State. The EPA simply requires the State to implement the State's EGU–SO_2-emission-reduction-requirement decision in a manner that avoids the otherwise likely, extreme disruption of the title IV SO_2 cap and trade system that is described above. Further, the

[147] While the title IV cap and trade system could be replaced by a new CAIR SO_2 cap and trade system that did not address the problems caused by surplus title IV allowance, that new cap and trade system would not be nationwide like the title IV cap and trade system and so would not cover sources outside the CAIR SO_2 region.

[148] The EPA notes that the potential for increased emissions *within* the CAIR SO_2 region would occur before the implementation of the CAIR SO_2 program and is addressed by allowing pre-2010 banked title IV allowances to be used to meet the CAIR allowance holding requirement beginning in 2010.

[149] While the potential for increased emissions outside the CAIR SO_2 region supports EPA's conclusion, EPA maintains that, even in the absence of any such increase, the other considerations discussed above are sufficient to justify the conclusion that the retirement of title IV allowances does not impermissibly interfere with the Acid Rain Program and is reasonable.

State may choose what mechanism to include in its SIP revision for achieving the required allowance retirement, and EPA will review the effectiveness of the mechanism in achieving such retirement, and approve and adopt the mechanism if appropriate, in an EPA rulemaking concerning the SIP revision. Therefore, EPA concludes that the allowance-retirement requirement is lawful and is a reasonable condition for EPA approval of those State SIPs that require EGU SO_2 emission reductions without using the CAIR model SO_2 trading program.

The EPA notes that the requirement to retire excess title IV allowances—where a State adopts the CAIR model SO_2 trading program or where a State SIP obtains EGU emissions reductions through some other means—is reflected in provisions in both the proposed rules in the SNPR (*i.e.*, in proposed §§ 51.124(p) and 96.254(b)) and in the final rules adopted by today's action (*i.e.*, in final §§ 51.124(p) and 96.254(b)). In reviewing the proposed rules in light of the comments received, EPA has concluded that, for consistency and clarity, the Acid Rain Program regulations should also reference this same retirement requirement. Consequently, today's action adds a new paragraph (a)(3) to § 73.35 of the Acid Rain Program regulations that reiterates the requirement—addressed in the preamble and regulations in both the SNPR and today's action—that title IV allowances previously used to meet the allowance-holding requirement in the CAIR model trading program in § 96.254(b) or otherwise retired in accordance with § 51.124(p) cannot be used to meet the allowance-holding requirement in the Acid Rain Program. Additional revisions of the Acid Rain Program regulations are discussed below.

3. Revisions to Acid Rain Regulations

In the SNPR, EPA proposed to revise the Acid Rain Program regulations, effective July 1, 2005, to implement the allowance-holding requirement on a source-by-source, rather than on a unit-by-unit, basis. Instead of requiring each unit to hold an amount of allowances in its Allowance Tracking System account (as of the allowance transfer deadline) at least equal to the tonnage of SO_2 emissions for the unit in the preceding calendar year, the proposal required each source to hold an amount of allowances in its Allowance Tracking System account at least equal to the tonnage of SO_2 emissions for all affected units at the source for such calendar year. Because language reflecting or referencing the unit-by-unit compliance approach is included in many provisions of the Acid Rain Program regulations, a significant number of proposed rule revisions were necessary to implement source-by-source allowance holding.

In today's final rule, EPA is adopting, with minor modifications, the proposed rule revisions implementing source-by-source compliance with the allowance-holding requirement. As explained in detail in the SNPR (69 FR 32698–32701), EPA finds that: Title IV is ambiguous with regard to whether unit-by-unit compliance is required and so EPA has discretion in this matter; it is important to provide additional compliance flexibility by allowing a unit at a source to use allowances from any other unit at the same source; and many other, non-allowance-holding provisions of title IV evidence a unit-by-unit orientation. Further, as discussed in the SNPR, EPA concludes that the adoption of source-level compliance reasonably balances these considerations. In balancing these considerations, EPA also concludes that company-level compliance is not appropriate because it represents too much of a deviation from the unit-by-unit orientation in the non-allowance-holding provisions of title IV and is likely to require much more dramatic changes in the operation of the Acid Rain Program. *See* 69 FR 32699–700. It is important to note that the final rule revisions, like the proposed revisions, change only the allowance-holding requirement and not the emissions monitoring and reporting requirements, which continue to be applied unit by unit.

In today's action, EPA is making the source-level-compliance rule revisions effective July 1, 2006, which is 1 year later than proposed. The shift from unit-level to source-level compliance will require software changes and testing to ensure that the Allowance Tracking System operates properly. Currently, EPA is in the process of conducting a general review and re-engineering of the Allowance Tracking System and Emissions Tracking System and anticipates completing the process in 2006. The process of shifting the Allowance Tracking System to source-level compliance will be much more efficient and less likely to have adverse results on the system if the shift is coordinated with the general review and re-engineering and therefore implemented starting July 1, 2006. Further, as discussed below, this delay of implementation for 1 additional year will give owners additional time to make changes that they determine are necessary in order to adapt to source-level compliance.

Some commenters support the shift to source-by-source allowance holding, and some oppose the change. One commenter opposing the change claims that a source-by-source allowance-holding requirement is ''contrary to market-based principles.'' According to the commenter, market-based systems give operators the tools for achieving compliance through allowance transfers, but with source-level compliance the operators do not have to take any action to maintain sufficient allowances because EPA will move the allowances around for them.

The commenter's argument is based on an incorrect premise. Whether compliance is unit-by-unit or source-by-source, the owner or owners of the affected units at each source must take the same types of actions in order to comply with the applicable allowance-holding requirement. In particular, under source-level compliance, such owner or owners must reduce emissions, retain allowances allocated to such units, obtain additional allowances, or take a combination of these actions to ensure that the Allowance Tracking System account for the source holds enough allowances to cover the total emissions of the affected units at the source. The owner or owners also have the option of reducing emissions below allocations so that there are extra allowances available to hold for future use or sale. If the owner or owners do not have enough allowances to cover the emissions from the source, EPA will not move, on its own initiative, allowances into the source's compliance account from other sources' accounts or from general accounts, even if there are extra allowances in the other accounts. The only difference between the types of actions owners must take under the unit-level and source-level approaches is that, under unit-level compliance, the owners must transfer allowances from one unit at a source to a second unit at that source in order to use the first unit's allowances for compliance by the second unit while, under source-level compliance, any allowance held for compliance for the first unit can be used—without a transfer—for compliance by the second unit. This difference is reflected in the Allowance Tracking System, which, under the unit-level approach, includes a separate account for each unit and, under the source-level approach, includes a single account for all the affected units at a single source.

In summary, the mechanism, and the owners' responsibilities, for achieving compliance with the allowance-holding requirements are analogous under unit-by-unit and source-by-source compliance, except that, under source-by-source compliance, allowances need not be transferred among units at the same source. The EPA does not believe that the source-by-source approach is any less market-based than the unit-by-unit approach. Owners will still have the ability to reduce emissions or purchase or sell allowances and the responsibility to take actions (including the holding of extra allowances) to ensure they have enough allowances to cover emissions. Moreover, the market-price of allowances will still play a crucial role in owners' decisions on what actions to take. The EPA's adoption of source-by-source compliance preserves market-based principles, while reasonably balancing of the ambiguity of title IV, the need for additional compliance flexibility, and the unit-by-unit orientation of many provisions in title IV. *See* 69 FR 32699–700.

The commenter also argues that having a source-level allowance-holding requirement in the Acid Rain Program (and the CAIR model cap and trade program) is inconsistent with unit-level compliance in the NO_X SIP Call cap and trade program. However, other than pointing out this difference, the commenter fails to explain why the programs must be identical in this regard. Based on experience with the Acid Rain Program (as well as the NO_X SIP Call trading program), EPA concludes that a source-level allowance-holding requirement will result in a somewhat less complicated program and a reduced likelihood of inadvertent, minor errors, while achieving the program's environmental goals. *See* 69 FR 32699–700.

The commenter suggests that, instead of adopting source-level compliance, EPA revise the Acid Rain Program regulations to allow for source over-draft accounts, like those allowed in the NO_X SIP Call cap and trade program. Under the NO_X SIP Call program, each source may have a source over-draft account, in which may be held extra allowances that may be used for compliance by any affected unit at the source. However, EPA believes that source-level compliance is a better approach than unit-level compliance with over-draft accounts. Relatively few owners in the NO_X SIP Call cap and trade program actually put allowances in over-draft accounts, and achievement of compliance is made more complicated by the ability of all units at a source to draw on the over-draft account (if any allowances are put in it) but the inability of any unit to use extra allowances held instead by another unit at the source. Consequently, rather than adopting in the Acid Rain Program the unit-level approach with over-draft accounts, EPA is today adopting the source-level approach in the Acid Rain Program and may consider in the future, as appropriate, adopting the source-level approach in other programs using unit-level compliance.

One commenter states that EPA should revise the Acid Rain Program regulations to allow owners, each year, the option of choosing whether to use unit-level or source-level compliance. According to the commenter, significant investments have been made to monitor and report emissions and surrender allowances under the existing Acid Rain Program regulations, and shifting to source-level compliance will require substantial resources and time. The commenter also states that unit-based compliance should be retained as an option ''to accommodate joint ownership and other special arrangements that may not affect an entire facility.''

The EPA rejects the suggestion of allowing each owner the option, for each year and for each source, of choosing between unit-level and source-level compliance. Such an approach would significantly complicate the achievement by sources, and the determination by EPA, of compliance. The potential for error (*e.g.*, due to erroneous assumptions about whether unit-or source-level compliance would be applicable to a particular source for a particular year) on the part of owners or EPA would be significantly increased. Moreover, this complicated approach would result in inconsistent treatment from source to source and year-to-year. Further, the commenter provided only vague assertions about the benefits of unit-based compliance in certain circumstances and did not assert—much less show—that source-level compliance cannot be accommodated under those circumstances. The EPA maintains that the only reasonable options for the allowance-holding requirement in the Acid Rain Program are either generally requiring compliance by all sources each year on a unit-level basis (as in the existing regulations) or requiring compliance by all sources each year on a source-level basis (as in the proposed revisions to the regulations). For the reasons discussed above, EPA believes that source-level compliance for the allowance-holding requirement is preferable. By postponing until July 1, 2006 the effective date of the rule revisions shifting to source-level compliance (with the result that 2006 is the first year of source-level compliance), EPA is providing owners a reasonable amount of time to make any necessary adjustments, such as those claimed by the commenter. Further, as noted above, the rule revisions change only the allowance-holding requirement and not the emissions monitoring and reporting requirements. This should limit the scope of adjustments necessary for owners to implement source-level compliance and will preserve the availability of reliable, unit-level emissions data.

Because unit-level compliance is reflected throughout the Acid Rain Program regulations, numerous revisions of the regulations are necessary to implement source-level compliance. (None of these changes are to the emissions monitoring and reporting provisions in part 75 since monitoring and reporting continue to be on a unit basis.) One commenter requested that EPA provide ''more in-depth detail'' on the proposed revisions. However, in the SNPR, EPA described the types of, and reasons for, revisions that are necessary for source-level compliance (69 FR 32700–01) and set forth all of the specific, proposed changes (69 FR 3273–41). Moreover, no commenters stated that they did not understand any specific, proposed revision or the reason for any specific revision. The EPA notes that in reviewing the proposed Acid Rain rule revisions in light of the comments, EPA found some additional references in the Acid Rain rule to unit-level compliance that should be revised to reflect source-level compliance. In today's action, EPA is adopting revisions of these additional references (*e.g.*, changing references to a ''unit's account'' or a ''unit account'' to a source's ''compliance account'') that are analogous to the revisions specifically identified in the SNPR.[150]

Another commenter opposed the rule revisions implementing source-level compliance on several other grounds. The commenter claims, without citing any statutory support, that the Acid Rain Program is based on ''control of emissions at the unit level'' so that, in the event of excess emissions, the ''source as a whole would not be punished'' and ''corrective action could take place'' at the particular unit. According to the commenter, source-level compliance will: Make it harder to determine which unit caused excess emissions; make the existing Acid Rain

[150] This approach is consistent with the SNPR, where EPA proposed to convert all references, including any initially missed in the SNPR, from unit- to source-level compliance (69 FR 32700).

permits meaningless; make the individual unit allowance allocations meaningless; and cause confusion over which units at a source are affected units.

While there are many non-allowance-holding provisions in title IV that have a unit-by-unit orientation, EPA disagrees with the commenter's basic assertion that the purpose of the Acid Rain Program is to control emissions on a unit-by-unit basis and that there is a need to ''distinguish'' the compliance of each individual unit. The provisions concerning application of the allowance-holding requirement are ambiguous as to whether EPA must implement the requirement on a unit-level or a source-level, and the environmental benefits of the Acid Rain Program will still be realized with source-level compliance. *See* 69 FR 32699–700. Further, while EPA will determine compliance on a source-by-source basis, nothing in the regulations prevents owners (*e.g.*, owners of units at sources with multiple units and multiple owners or owners of units with multiple owners and exhausting through a common stack) from determining by agreement which owners will bear any excess emissions penalties that occur at the plant and have to take correction actions. Indeed, owners are likely to already have these types of agreements in cases of units or sources with multiple owners. This is because the Acid Rain Program regulations already allow a unit at a multi-unit source to use some allowances from other units at the source (albeit to cover most but not all of the potential excess emissions) and already allow one unit exhausting from a common stack to use allowances from another unit at that stack (without any limitation on such use). *See* 40 CFR 73.35(b)(3) and (e). In addition, while the Acid Rain permits will have to be revised in the future to reflect source-level compliance, today's rule does not make source-level compliance effective until 2006. Permits will not have to be revised until around the end of 2006, which should provide States a reasonable opportunity to amend the permits. Contrary to the claims of the commenter, source-level compliance does not make the unit-by-unit allocations meaningless; the unit-by-unit allocations (set forth in Table 2 of § 72.10) will determine the amount of allocations reflected in each Allowance Tracking System source account, which amount will equal the sum of the allocations for all affected units at the source. Finally, the commenter failed to explain how the source-level allowance-holding requirement could cause ''confusion'' over which units are affected units. This source-level requirement does not change the applicability provisions, which are still applied unit by unit.

As discussed in the SNPR, EPA proposed—in addition to the rule revisions to implement source-level compliance—other revisions of the Acid Rain Program regulations in order to facilitate coordination of the Acid Rain Program and the CAIR SO_2 cap and trade program. These additional revisions were described and explained in the SNPR (69 FR 32701). The EPA is adopting these revisions for the reasons in the SNPR, as amplified below. Most of these revisions are supported, or not opposed, by commenters, but some commenters objected to certain revisions.

For example, EPA noted that it had recently changed the ''cogeneration unit'' definition in § 72.2 in June 2002 (67 FR 40394, 40420; June 12, 2002). The original definition in § 72.2 had been used since the commencement of the Acid Rain Program. The only significant difference between the original and revised definitions is that the former refers to a unit ''having the equipment used to produce'' electricity and useful thermal energy through sequential use of energy, while the latter simply refers to a unit ''that produces'' electricity and useful thermal energy in that manner. The reason that EPA gave for revising the definition in June 2002 was to conform with the definition in the Section 126 rule. However, the Section 126 rule (and the NO_X SIP Call) did not actually specify a ''cogeneration unit'' definition. Consequently, there is no reason to use the June 2002 revised definition. Moreover, EPA is concerned that the change in the definition of ''cogeneration unit'' as of June 2002 may cause confusion or raise question about what units qualify for exemptions for ''cogeneration units'' from the Acid Rain Program. Under these circumstances, EPA concludes that the definition should be changed back to the original definition in § 72.2 and, in any event, intends to interpret the June 2002 revised definition as having the same meaning as the original definition. One commenter raised concerns that EPA did not provide any ''detailed analysis'' of the implications of changing the ''cogeneration unit'' definition. However, as discussed above, the change simply reinstates the definition that had been used in the Acid Rain Program from the initial promulgation of implementing regulations in 1993 until 2002. No commenter asserted that reverting to the longstanding, original definition would be disruptive.

Another Acid Rain Program rule revision proposed in the SNPR is the elimination of the requirement for owners and operators to submit an annual compliance certification report for each source. One commenter expressed concern, because the purpose of the annual certification is to ensure that the designated representative is ''aware and has assured the quality of the data'' being submitted to EPA. However, as noted in the SNPR, designated representatives must evidence such awareness and compliance by submitting, with each quarterly emissions report, a certification that the monitoring and reporting requirements under part 75 of the Acid Rain Program regulations have been met. *See* 40 CFR 75.64(c). Quarterly emissions reports are available on-line to the public and the States. In addition, owners and operators of sources subject to the Acid Rain Program must submit, under title V of the CAA, annual compliance certification reports concerning all CAA requirements (including Acid Rain Program requirements). Under these circumstances, EPA maintains that the separate Acid Rain Program annual compliance certification reports are duplicative and unnecessary. The EPA notes that it appears that few, if any, requests for copies of these Acid Rain Program reports have been made by States or any other persons since the commencement of the Acid Rain Program. Apparently, other certifications and submissions required of owners and operators have been sufficient for the purposes cited by the commenter.

The SNPR also included proposed revisions eliminating the requirement under the Acid Rain Program for a 1-day newspaper notice for designation of designated representatives and authorized account representatives. One commenter suggests that this notice should be replaced by a requirement to notify the State permitting authority. The EPA notes that information on designated representatives and authorized account representatives is already available to State permitting authorities through on-line access to the Allowance Tracking System. Moreover, EPA is in the process of developing, and anticipates establishing in the near future, the ability to send State permitting authorities (at their request) on-line notices of changes in designated representatives (who are also the authorized account representatives for affected sources' accounts).

Other proposed Acid Rain Program rule revisions on which EPA received adverse comment are the removal of § 73.32 (prescribing the contents of an allowance account) and § 73.51 (prohibiting the transfer of allowances from a future year subaccount to a subaccount for an earlier year). Section 73.32 sets forth a rather self-evident list of information that must be recorded in an allowance account in the Allowance Tracking System, such as the name of the authorized account representative, the persons represented by the authorized account representative, and the transfers of allowances in and out of the account. This section also references information on compliance or current year subaccounts and future year subaccounts, as well as emissions information. As discussed in the SNPR, several items on the list of informational contents for allowance accounts are out-of-date in that they do not reflect how the electronic Allowance Tracking System operates or will operate in the near future. For example, the electronic Allowance Tracking System does not currently use or refer to subaccounts, which will continue to be unnecessary in the context of source-level compliance.[151] *See* 69 FR 32700–01. In addition, while § 73.32 states that emissions data are reflected in the Allowance Tracking System account, such data are currently available instead through the electronic Emissions Tracking System. Because the information list in § 73.32 contains either self-evident items or items that are out-of-date and because the NO_X Allowance Tracking System has been operating successfully even though the model NO_X Budget cap and trade rule and State cap and trade rules under the NO_X SIP Call lack a provision analogous to § 73.32, EPA is removing § 73.32. EPA notes that the removal of the section will not mean that the information contained in allowance accounts ''can be changed at will.'' The format for allowance accounts is set forth in the electronic Allowance Tracking System and implements the requirements in the Acid Rain Program regulations concerning the holding, transferring, recording, and deducting of allowances.

Section 73.51 prohibits the transfer of allowances from a future year subaccount to a subaccount for an earlier year. The removal of this section is consistent with the elimination throughout the rest of the Acid Rain Program regulations, as discussed in the SNPR (*id.*), of any references to such subaccounts. Further, the prohibition on using allowances allocated for a year to meet the allowance-holding requirement for a prior year is retained in other provisions of the Acid Rain Program regulations. Consequently, EPA is removing § 73.51.

C. How Does the Rule Interact With the Regional Haze Program?

This section discusses the relationship of the CAIR cap and trade program for EGUs with the regional haze program under sections 169A and 169B of the CAA, in particular the requirements for Best Available Retrofit Technology (BART) for certain source categories including EGUs. The legislative and regulatory background of the BART provisions were presented in some detail in the SNPR. (See 69 FR 32684, 32702–704, June 10, 2004). In brief, BART regulations consist of two components. The first, promulgated in 1980, addresses visibility impairment that can be ''reasonably attributed'' to a single source or small group of sources. (45 FR 80085; December 2, 1980, codified at 40 CFR 51.302). The second component addresses BART in relation to regional haze (visibility impairment caused by a multitude of broadly distributed sources) and was promulgated as part of the Regional Haze Rule. (64 FR 35714; July 1, 1999). Certain parts of the BART provisions in that rule were vacated by the U.S. Court of Appeals for the DC Circuit in *American Corn Growers et al.* v. *EPA,* 291 F.3d 1 (DC Cir., 2002). To address that decision, in May 2004, EPA proposed changes to the Regional Haze Rule and reproposed the Guidelines for BART Determinations (originally proposed in 2001) (69 FR 25185, May 5, 2004).

On February 18, 2005, the DC Circuit decided another case dealing with BART and a BART alternative program, *Center for Energy and Economic Development* v. *EPA*, No. 03–1222, (DC Cir. Feb. 18, 2005) (''*CEED*''). In this case, the court granted a petition challenging provisions of the regional haze rule governing the optional emissions trading program for certain western States and Tribes (the ''WRAP Annex Rule''). The holdings of the case are relevant to today's action in several respects.

Most importantly for purposes of the CAIR, *CEED* affirmed EPA's interpretation of CAA 169A(b)(2) as allowing for non-BART alternatives where those alternatives make greater progress than BART. (*CEED*, slip. op. at 13) (finding that EPA's interpretation of CAA 169(a)(2) as requiring BART only as necessary to make reasonable progress passes the two-pronged Chevron test).

The particular provisions involved in *CEED* applied, on an optional basis, only to nine western States[152] (none of which are in the CAIR region) and the Tribes therein. The provisions, contained in 40 CFR 51.309 (''section 309'') required among other things that States choosing to participate in a ''backstop''[153] cap and trade program must demonstrate that the emissions reductions under the program resulted in greater progress towards the national visibility goals than would BART. At issue was the particular methodology required for this demonstration. Specifically, EPA's rule required that visibility improvements under source-specific BART—the benchmark for comparison to the cap and trade program—must be calculated based on the application of BART controls to all sources subject to BART.[154] Although *American Corn Growers* had vacated this cumulative visibility approach in the context of determining BART for individual sources, EPA believed that it was still permissible to require this methodology in the context of a BART-alternative program. The DC Circuit in *CEED* held otherwise, stating: ''EPA cannot under § 309 require states to exceed invalid emission reductions (or, to put it more exactly, limit them to a § 309 alternative defined by an unlawful methodology).'' (*Id.* at 14).

Thus, *CEED* firmly established two principles: (1) The CAA allows States to substitute other programs for BART where the alternative achieves greater progress, and (2) EPA may not require States to evaluate visibility improvement on a cumulative basis as a condition for approval of a BART-alternative. The first principle validates EPA's proposal to allow the CAIR to substitute for BART. The second

[151] In reviewing the proposed Acid Rain Program rule revisions, EPA found some additional references to ''subaccounts'' that were not specifically noted in the SNPR. For consistency and clarity in the Acid Rain Program rules, EPA is adopting in today's action revisions (*e.g.,* chaning the term ''subaccount'' to ''compliance account'') of these additional references, which revisions are analogous to those specifically set forth in the SNPR. This approach is consistent with the SNPR, where EPA proposed to convert all references, including any initially missed in the SNPR, from subaccount to compliance account, (69 FR 32700).

[152] Arizona, California, Colorado, Oregon, Idaho, Nevada, New Mexico, Utah, and Wyoming.

[153] The trading program is referred to as a ''backstop'' because under the WRAP Annex, States have the opportunity to achieve specified emission milestones using voluntary measures, with the trading program coming into effect only if those milestones are exceeded.

[154] The methodology is prescribed in 40 CFR 51.308(e)(2) and incorporated into § 309 by reference at 40 CFR 51.309(f).

principle is not at issue in the CAIR context, because EPA is not proposing to impose the cumulative visibility methodology upon States, nor to require States to treat the CAIR as having satisfied their BART obligations.

Nonetheless, EPA has determined that it is premature to make a final determination regarding the sufficiency of the CAIR as a BART alternative, primarily because (1) the guidelines for source-specific BART determinations, in response to *American Corn Growers* have not been finalized, and (2) there is now a need to revise the Regional Haze Rule and the guidelines for BART-alternative programs in response to *CEED*. The source-specific BART guidelines will be finalized on or before April 15, 2005, under a consent decree. The rule changes and revisions to the BART-alternative guidelines will be proposed soon thereafter.

Therefore, we are making no final determination in today's action with respect to BART. The EPA continues to believe, however, that the CAIR will result in greater progress in visibility improvement than BART, as explained below.

1. How Does This Rule Relate to Requirements for BART Under the Visibility Provisions of the CAA?

a. Supplemental Notice of Proposed Rulemaking

In the SNPR, we proposed that States which adopt the CAIR cap and trade program for SO_2 and NO_X would be allowed to treat the participation of EGUs in this program as a substitute for the application of BART controls for these pollutants to affected EGUs.[155] To give this option effect, we proposed an amendment to the Regional Haze Rule which would add a section at 40 CFR 51.308(e)(3), as follows:

(3) A State that opts to participate in the Clean Air Interstate Rule cap and trade program under part 96 AAA–EEE need not require affected BART-eligible EGUs to install, operate, and maintain BART. A State that chooses this option may also include provisions for a geographic enhancement to the program to address the requirement under § 51.302(c) related to BART for reasonably attributable impairment from the pollutants covered by the CAIR cap and trade program.

This proposal is consistent with currently existing provisions which allow States to develop cap and trade programs or other alternative measures in lieu of the application of BART on a source specific basis. (*See* 40 CFR 51.308(e)(2) and 64 FR 35714, 35741–35743, July 1, 1999). The proposal was based on the application of the proposed two-pronged test for whether an alternative to BART is ''better than BART'' which was proposed in the 2001 BART guidelines and reproposed without changes in our May, 2004 proposed guidelines for BART determinations (69 FR 25184, May 5, 2004).

Specifically, the re-proposed BART Guidelines provide that if the geographic distribution of emissions reductions is anticipated to be similar under both programs, the trading program (or other alternative measure) must be shown to achieve greater overall emissions reductions than the application of source-specific BART. If the trading program is anticipated to result in a different geographic distribution of emissions reductions than would source-specific BART, the trading program must be shown to result in no decline in visibility at any Class I area, and in an overall improvement in visibility on an average basis over all affected Class I areas (69 FR 25184, 25231). Because we had not yet determined whether there is a difference in the geographic distribution of emissions reductions between the CAIR and the application of source-specific BART in the CAIR region, we assessed the difference between the two programs by evaluating the visibility impacts of each program, using this proposed two-pronged test.

The emissions projections and air quality modeling used to demonstrate that the CAIR satisfies this proposed two-pronged test were presented in a document entitled Supplemental Air Quality Modeling Technical Support Document (TSD) for the Clean Air Interstate Rule (May 4, 2004). In brief, we found that the CAIR would not result in a degradation of visibility from current conditions at any Class I Area nationwide. Within the CAIR-affected States and New England, EPA found that the CAIR would produce greater visibility benefits—specifically, an average improvement of 2.0 deciviews, as compared to 1.0 for BART. The EPA also found that average visibility improvement for Class I areas nationwide would be 0.7 deciviews under the CAIR, compared to 0.4 deciviews under BART. The EPA noted in the SNPR and the TSD that because the emissions scenarios used in these analyses were developed for different purposes, the scenarios varied slightly from the scenarios which would be ideal for this test. The EPA committed to conduct additional analyses, and those analyses have now been done. The new modeling and results are discussed in more detail in section IX.C.2 below.

b. Comments and EPA's Responses

Several commenters argued that a categorical exclusion of sources from BART would violate the CAA, as interpreted by the U.S. Court of Appeals for the DC Circuit in *American Corn Growers* v. *EPA,* 291 F.3d 1, 2002, by illegally constraining the discretion Congress conferred to States in making BART determinations and by depriving States of an adequate opportunity to evaluate the emissions reductions in light of the BART requirement. Some States also expressed a desire to retain their discretion to require BART. Additionally, some commenters asserted that EPA could not offer an exemption to BART unless the conditions for exemptions provided by CAA 169A(c) are met, including a showing that the source in question will not, alone or in combination with other sources, emit any pollutant which may reasonably be anticipated to cause or contribute to impairment at any Class I area, and the concurrence of the appropriate Federal Land Manager with the exemption determination.

The EPA agrees that under the CAA and the *American Corn Growers* case, EPA may not preclude a State from conducting its own BART analysis, nor from requiring BART controls at individual sources as determined appropriate through such analysis. Accordingly, as noted above, the proposed regulatory change to the Regional Haze Rule would provide that a CAIR affected State ''need not require affected BART-eligible EGUs to install, operate, and maintain BART'' if such State opts to participate in the CAIR cap and trade program. The optional nature of this language (''need not'' rather than ''may not'') is consistent with the *American Corn Growers* decision, because it does not attempt to mandate that States must consider the CAIR as having met the requirements of BART.

The SNPR preamble summarized the proposal by stating that ''EPA proposes that BART-eligible EGUs in any State affected by CAIR may be exempted from BART controls for SO_2 and NO_X if that State complies with the CAIR requirements through adoption of the CAIR cap and trade programs for SO_2 and NO_X emissions.'' (69 FR 3270). That statement accurately reflected the optional nature of the better-than-BART substitution policy, by providing that sources ''may'' be granted such regulatory flexibility. However, the use of the term ''exempted'' in this context

[155] The SNPR preamble used the term ''exemption'' in describing this policy. As clarified below, and as consistent with the proposed regulatory language, the better-than-BART policy is not actually an exemption but rather an alternative means of compliance.

was somewhat imprecise. EPA agrees that sources may not be ''exempt'' from BART requirements unless the requirements of 169A(c) are fulfilled. The better-than-BART policy is not an ''exemption'' from BART; it is an alternative regulatory program that would allow Congressionally required emissions reductions from BART-eligible sources to be made in a more cost-effective manner. Moreover, as explained elsewhere in the SNPR and again below, BART-eligible EGUs would not be ''exempt'' from BART because, until the emissions reductions required by the CAIR are fully realized, such sources would remain subject to the possibility of being required to install BART controls if deemed necessary to meet requirements regarding reasonably attributable visibility impairment, as provided by 40 CFR 51.302.

Several commenters asserted that because Congress singled out 26 source categories for the application of BART, there is no basis in law for EPA to ''exempt'' some of these categories. These comments amount to facial challenges of EPA's authority to approve SIPs which contain alternative strategies, rather than source-specific BART requirements, for BART-eligible sources.

The EPA's authority to approve alternative measures to BART, where those measures achieve greater reasonable progress than would BART, was recently upheld by the DC Circuit. (*CEED,* slip. op. at 13). See also Central Arizona *Water Conservation District* v. *EPA,* 990 F.2d 1531, 1543, (1993) (Upholding EPA's interpretation of CAA 169A(b)(2)as providing discretion to adopt implementation plan provisions other than those provided by BART analyses in situations where the agency reasonably concludes that more reasonable progress will thereby be attained).

Similarly, some commenters stated that the CAIR could not substitute for BART because the CAIR and BART are authorized by separate parts of the CAA. They argue that allowing reductions required by a provision of the CAA not linked to visibility improvement to substitute for BART would alter Congress' ''mandate'' that certain source categories make reductions for visibility in excess of what other CAA provisions require of those sources.[156] Commenters also point to Regional Haze Rule section 308(e)(2), as evidence that reductions from other programs such as title IV and the NO_X SIP Call must be achieved in addition to, and not as a substitute for, BART. Commenters also argue that EPA (and States) will need all available tools, including BART, to meet visibility and NAAQS requirements.

Again, under our interpretation of CAA section 169A(b)(2) as upheld in *CEED* and *Central Arizona Water,* Congress did not ''mandate'' that emission reductions from certain source categories be obtained by the installation of BART controls. Instead, the CAA allows for alternative measures to BART—whether for EGUs or non-EGUs—where those measures result in greater reasonable progress, and as explained below, we have determined that greater reasonable progress can be obtained from the EGU sector through the use of the CAIR cap and trade program. However, if a State believes more progress can be made at affected Class I areas by utilizing BART, the State need not make the determination that the CAIR substitutes for BART in that State. Therefore, EPA is not eliminating any tools available to the States.

With respect to Regional Haze Rule section 308(e)(2), EPA does not believe that this section provides any support for the notion that emissions reductions from other programs must necessarily be in addition to, not substitute, for BART. We first note that the decision in CEED necessitates revisions to 308(e)(2), at least in the provisions requiring visibility to be evaluated on a cumulative basis in defining the BART benchmark for comparison to BART alternative programs. It remains to be seen whether 308(e)(2)(iv), which requires that emissions reductions from the BART alternative be ''surplus to reductions resulting from measures adopted to meet requirements as of the baseline date of the SIP,'' will be changed. Even if that section remains unchanged, the CAIR complies with it. The baseline date of Regional Haze SIPs is 2002.[157] Since any emissions reduction requirements to meet the CAIR would necessarily be adopted after 2002, CAIR-required reductions would clearly be surplus to measures adopted as of the baseline year.[158]

Several commenters argued that the question of whether BART is better than the CAIR is properly addressed in the BART rulemaking, not in today's action, and that the better-than-BART determination is otherwise premature. While EPA believes that our current analysis demonstrates that the CAIR is better than BART (based on the criteria in our May 2004 BART proposal), and that the range of uncertainty regarding the presumptive BART controls for EGUs to be finalized in the BART guidelines is not likely to alter that demonstration, we agree that we cannot make a final determination that CAIR is better than BART until the changes to the regional haze regulations required by both *American Corn Growers* and *CEED* are finalized.

Several commenters felt the CAIR should be considered better than BART for a State whether or not that State participates in the CAIR cap and trade program, as long as the State achieves its emission reduction requirement under the CAIR. Conversely, one commenter felt that CAIR reductions should be considered better than BART only when a State does not participate in the cap and trade program, thereby ensuring that the reductions will occur in-State.

Our preliminary demonstration that the CAIR results in more reasonable progress than BART for EGUs is based on a comparison of emissions reductions from EGUs, and attendant air quality effects, under the CAIR as compared to under BART as proposed in May, 2004. If emissions reductions are achieved from other source sectors, a similar analysis would have to be conducted for those sector(s) before it could be determined that the reductions were better than BART for affected source categories. For example, if a State either wants to use EGU emissions reductions under the CAIR to substitute for BART for non-EGUs, or use non-EGU emissions reductions to substitute for BART for EGUs, that could be allowed as an alternative measure to BART provided a similar ''better-than-BART'' determination is made for the sectors involved.

A few commenters believed EPA should not limit the substitution of the CAIR for BART to States that are required to meet CAIR for both SO_2 and NO_X on an annual basis, but rather should also allow it for States which are only required to reduce NO_X during the ozone season. Because the modeling scenarios were based on the pollutants

[156] CAIR is linked to visibility improvements insofar as it attempts to make progress towards attainment of the $PM_{2.5}$ NAAQS, which would, among other things, improve visibility.

[157] See ''2002 Base Year Emission Inventory SIP Planning: 8-hr Ozone, $PM_{2.5}$ and Regional Haze Programs,'' November 8, 2002, Guidance Memorandum, *http://www.epa.gov/ttn/oarpg/t1/memoranda/2002bye_gm.pdf.*

[158] The purpose of providing a cut-off year for SIP measures to which the alternative must be surplus is to prevent an untenable situation where programs being developed simultaneously must be surplus to each other. Establishing a baseline year allows States to continue to make reductions between that baseline date and the submittal of regional haze SIPs without being ''penalized'' for those reductions by not being allowed to count them as contributing to reasonable progress towards the national visibility goal.

covered by the CAIR in each affected State, our better-than-BART demonstration is limited to those scenarios. A State subject to the CAIR for NO_X purposes only would have to make a supplementary demonstration that BART has been satisfied for SO_2, as well as for NO_X on an annual basis.

A few commenters believed that the CAIR should satisfy BART for purposes of reasonably attributable visibility impairment as well as BART for purposes of regional haze. Several others commented that it was appropriate or legally necessary to preserve the authority of Federal Land Managers (FLMs) and States to certify impairment and make reasonable attribution determinations, which could subject a source to BART requirements even if the source is a participant in the CAIR cap and trade program. These commenters supported the use of a strategy similar to that employed by the Western Regional Air Partnership, which relies upon a Memorandum Of Understanding (MOU) between the FLMs and the States regarding the criteria by which certifications of impairment may be made, along with the possibility of ''geographic enhancements'' to the cap and trade program to accommodate the imposition of source-specific BART control requirements on a source within the cap and trade program.

As proposed in the SNPR, EPA continues to believe that reasonably attributable visibility impairment determinations under 40 CFR 51.302 must continue to be a viable option in order to insure against any possibility of hot-spots. We believe that a certification of reasonably attributable visibility impairment is fairly unlikely, given that there have been few such certifications since 1980, and given that the reductions from the CAIR and other recent initiatives will make such certifications decreasingly likely. We believe sources can be given sufficient regulatory certainty to enable effective participation in a cap and trade program through the use of MOUs and geographic enhancement provisions.

Some commenters believe that because section 169A(b)(2)(A) requires BART for an eligible source which may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area, EPA is without basis in law or regulation to base a better-than-BART determination on an analysis that does not evaluate visibility improvement at each and every Class I area, or one that uses averaging of visibility improvement across different Class I areas.

The criteria we applied in our present analysis—that greater reasonable progress is defined as no degradation at any Class I area, and greater overall average improvement—have not been finalized. However, we disagree with comments that 169A(b)(2)'s requirement of BART for sources reasonably anticipated to contribute to impairment at any Class I area [159] means that an alternative to the BART program must be shown to create improvement at each and every Class I area. Even if a BART alternative is deemed to satisfy BART for regional haze purposes, based on average overall improvement as opposed to improvement at each and every Class I Area, 169A(b)(2)'s trigger for BART based on impairment at any Class I area remains in effect, because a source may become subject to BART based on ''reasonably attributable visibility impairment'' at any area. (The EPA believes it is unlikely that a State or FLM will have need to certify reasonably attributable visibility impairment (RAVI) with respect to any EGU in the CAIR region, but nevertheless believes it is necessary to preserve this safeguard).

We also received a number of comments regarding the broader relationship between the CAIR and regional haze, including whether the CAIR meets reasonable progress requirements, as well as BART, for affected States; whether EPA should allow non-CAIR States to opt in to the CAIR cap and trade program to meet their BART requirements; and whether regional haze provisions should be used as a basis for expanding the CAIR rule to the rest of the States which were not included on the basis of contribution to $PM_{2.5}$ and ozone nonattainment. The EPA's responses to comments on these broader issues, which are not germane to the issue of whether the CAIR may substitute for BART for affected EGUs, are contained in the Response to Comment Document.

c. Today's Action

As discussed above, EPA has the authority to approve SIPs which rely upon a cap and trade program as an alternative to BART. However, at this time, we are deferring a final determination that, in EPA's view, the CAIR makes greater progress than BART for CAIR-affected States until such time as the BART guidelines for EGUs and the criteria for BART-alternative programs are finalized. At that time, contingent upon supporting analysis and our final rules governing the regional haze program, EPA will make a final determination as to whether the CAIR makes greater progress than BART, and can be relied on as an alternative measure in lieu of BART.

2. What Improvements Did EPA Make to the Bart Versus the CAIR Modeling, and What Are the New Results?

a. Supplemental Notice of Proposed Rulemaking

For the better-than-BART analysis in the SNPR, we used the Integrated Planning Model (IPM) to estimate emissions expected after implementation of a source-specific BART approach and after implementation of the CAIR cap and trade program for EGUs. We then used the Regional Modeling System for Aerosols and Deposition (REMSAD) air quality model to project the visibility impact of these IPM emissions predictions for both the CAIR and the nationwide source-specific BART scenarios. Specifically, EPA evaluated the model results for the 20 percent best days (that is, least visibility impaired) and the 20 percent worst days at 44 Class I areas throughout the country. Thirteen of these Class I areas are within States affected by the CAIR proposal, and 31 Class I areas are outside the CAIR region—29 in States to the west of the CAIR region, and 2 in New England States northeast of the CAIR region.

As explained in the SNPR, the ''CAIR'' scenario modeled was imperfect for purposes of this analysis in that it assumed SO_2 reductions on a nationwide basis (rather than in the CAIR region only) and assumed NO_X reductions requirements in a slightly different geographic region than covered by the proposed CAIR. The ideal scenario would have correctly represented the geographic scope of the CAIR SO_2 and NO_X reduction requirements, and included source-specific BART controls in areas outside the CAIR region. (This corrected scenario has been modeled for the NFR, as explained below).

The SNPR REMSAD modeling showed that under the proposed two-pronged test, CAIR controls achieved equal or greater visibility improvement than the application of source-specific BART to EGUs nationwide. The modeling predicted that the CAIR cap and trade program will not result in degradation of visibility, compared to

[159] The question of whether section 169A(b)(2) requires BART based on contribution to impairment at any Class I area is separate from the question of whether this section requires source-specific BART under all circumstances. As noted earlier, we interpret section 169A(b)(2) as requiring BART only as needed to make reasonable progress, thus allowing for alternative measures which make greater reasonable progress.

existing (1998–2002) visibility conditions, at any of the 44 Class I areas considered. It also indicated that CAIR emissions reductions as modeled produce significantly greater visibility improvements than source-specific BART. Specifically, for the 15 Eastern Class I areas analyzed, the average visibility improvement (on the 20 percent worst days) expected solely as a result of the CAIR was 2.0 deciviews, and the average degree of improvement predicted for source-specific BART was 1.0 deciviews. Similarly, on a national basis, the visibility modeling showed that for all 44 Class I areas evaluated, the average visibility improvement, on the 20 percent worst days, in 2015 was 0.7 deciviews under the CAIR cap and trade program, but only 0.4 deciviews under the source-specific BART approach.

b. Comments and EPA Responses

Several commenters noted that EPA did not model the ''correct'' emissions scenarios to compare the CAIR and BART controls. They suggested that a model run with the CAIR controls in the East and BART controls in the West should be compared to a model run with nationwide BART controls.

The EPA agrees (as we have already noted in the SNPR) that the suggested comparison of model runs is a more appropriate comparison of the CAIR and BART. The SNPR better-than-BART analysis was limited by the availability of the model results at the time. For the NFR, we have modeled nationwide BART for EGUs as proposed in the May 2004 guidelines and a separate scenario consisting of CAIR reductions in the CAIR-affected States plus BART-reductions in the remaining States (excluding Alaska and Hawaii). Additionally, we have improved the BART control assumptions (in both scenarios) by increasing the number of BART-eligible units included. Specifically, in the SNPR analysis, controls were ''required'' (*i.e.*, assumed by the model) for BART-eligible EGUs greater than 250 MW capacity, for both NO_X and SO_2. For today's action, BART controls are assumed for SO_2 for all BART-eligible EGU units greater than 100 MW, and NO_X controls for all BART-eligible EGU units greater than 25 MW.[160] This, along with a review of potentially BART-eligible EGUs, has expanded the universe of units assumed subject to BART in the modeling from 302 to 491.[161]

Several commenters noted that the better-than-BART visibility analysis only covered 44 Class I areas and did not adequately address visibility in all areas of the country.

For the NFR, we have significantly expanded the number of Class I areas covered by the analysis. The NPR and SNPR visibility analysis was limited by the availability of observed data from Inter-agency Monitoring of Protected Visual Environments (IMPROVE) monitors during the meteorological modeling year of 1996. There was complete IMPROVE data at 44 IMPROVE sites which represented 68 Class I areas.[162] All of the regions of the country (as defined by IMPROVE) were represented by at least one site, except the Northern Great Lakes region. For the final rule, the modeling has been updated to use a meteorological year of 2001. Therefore, the IMPROVE data for 2001 was used for the NFR better-than-BART analysis. For 2001, there were 81 IMPROVE sites with complete data,[163] representing 116 Class I areas. The NFR analysis accounts for visibility changes at 80 percent of the active IMPROVE sites in the lower 48 States. More importantly for today's rulemaking, the number of Class I areas in the East has been increased from 15 to 29 and now covers all IMPROVE-defined visibility regions within the CAIR-affected States, including the Northern Great Lakes.[164] We, therefore, believe the expanded geographic scope of Class I areas covered is sufficient for purposes of this analysis.

c. Today's Action

We have compared the two model runs (BART nationwide and BART in the West with the CAIR in the East) using the proposed two-pronged better-than-BART test. The results were analyzed at the 116 Class I areas that have complete IMPROVE data for 2001 or are represented by IMPROVE monitors with complete data. Twenty-nine of the Class I areas are in the East and 87 are in the West. Detailed modeling results for all 116 Class I areas are contained in the Better-than-BART TSD.[165] Results applicable to the better-than-BART proposed two-pronged test are summarized below.

The updated visibility analysis reaffirms that under the proposed two-pronged test, CAIR controls are better than BART for EGUs. The modeling predicts that the CAIR cap and trade program will not result in degradation of visibility on the 20 percent best or 20 percent worst days compared to the 2015 baseline conditions, at any of the 116 Class I areas considered.[166]

With respect to the greater-average-improvement prong, the modeling indicates that CAIR emissions reductions in the East produce significantly greater visibility improvements than source-specific BART. Specifically, for the 29 Eastern Class I areas analyzed, the average visibility improvement, on the 20 percent worst days, expected solely as a result of the CAIR applied in the East and BART applied in the West is 1.6 dv, as compared to the average degree of improvement predicted for nationwide source-specific BART of 0.7 dv. Similarly, on a national basis, the visibility modeling showed that for all 116 Class I areas evaluated, the average visibility improvement, on the 20 percent worst days, in 2015 was 0.5 dv under the CAIR cap and trade program in the East and BART in the West, but only 0.2 deciviews under the nationwide source-specific BART approach.

The modeling showed similar results for the 20 percent best visibility days, although there is less visibility improvement on the best days compared to the worst days. For the 29 Eastern Class I areas analyzed, the average visibility improvement, on the 20 percent best days, expected solely as result of the CAIR applied in the East and BART applied in the West is 0.4 dv, as compared to the average degree of

[160] Because the presumptive controls in the BART guidelines are applicable to coal-fired EGUs, the BART analysis does not assume controls on oil- and gas-fired units. However, NO_X emissions from all (not just BART-eligible) oil and gas steam plants and simple cycle turbines in the CAIR region in the 2010 base case are projected to be about 40,000 tons, or less than 1.5% of the projected total 2010 EGU emissions. By comparison, the modeling of the scenario of the CAIR (with BART in the non-CAIR region) resulted in 640,000 tons of NO_X per year less than the projected emissions under a nationwide BART scenario. Therefore, even if the 40,000 tons of NO_X emissions from oil and gas EGUs were reduced to zero under the BART scenario, the CAIR will still produce significantly greater emission reductions than BART. Also, not all of the oil and gas units associated with those 40,000 tons would be eligible for BART. The IPM does not predict any difference in SO_2 emissions from oil or gas-fired units between the CAIR and BART.

[161] See ''Memo From Perrin Quarles Associates, Inc. Re Follow-Up on Units Potentially Affected by BART, July 19, 2004,'' as Appendix A to the ''Better than BART'' TSD.

[162] Some Class I areas do not have IMPROVE monitors and are represented by nearby IMPROVE sites.

[163] This is the number of IMPROVE sites that are located at or represent Class I areas. There are additional IMPROVE protocol monitoring sites that are not located at Class I areas.

[164] There are 5 Class I areas in the East and 33 Class I areas in the West (outside of the CAIR control region) that do not have complete IMPROVE data for 2001.

[165] ''Demonstration that CAIR Satisfies the 'Better-than-BART' Test As Proposed in the Guidelines for Making BART Determinations,'' March, 2005.

[166] See Better-than-BART TSD for results at each Class I Area.

improvement predicted for nationwide source-specific BART of 0.2 dv. On a national basis, the visibility modeling showed that for all 116 class I areas evaluated, the average visibility improvement, on the 20 percent best days, in 2015 was 0.1 dv under both the CAIR cap and trade program in the East and BART in the West, and under the nationwide source-specific BART approach. The results are summarized in table IX–1.

TABLE IX–1.—AVERAGE VISIBILITY IMPROVEMENT IN 2015 VS. 2015

Base Case (deciviews)

Class I Areas	CAIR + BART in West		Nationwide BART	
	East [167]	National	East	National
20% Worst Days	1.6	0.5	0.7	0.2
20% Best Days	0.4	0.1	0.2	0.1

The results clearly indicate that the CAIR will achieve greater reasonable progress than BART as proposed, measured by the proposed better-than-BART test. At this time, we can foresee no circumstances under which BART for EGUs could produce greater visibility improvement than the CAIR. However, for the reasons noted in section IX.C.1. above, we are deferring a final determination of whether the CAIR makes greater reasonable progress than BART until the BART guidelines for EGUs and the criteria for BART-alternative programs are finalized.

D. How Will EPA Handle State Petitions Under Section 126 of the CAA?

Section 126 of the CAA authorizes a downwind State to petition EPA for a finding that any new (or modified) or existing major stationary source or group of stationary sources upwind of the State emits or would emit in violation of the prohibition of section 110(a)(2)(D)(i) because their emissions contribute significantly to nonattainment, or interfere with maintenance, of a NAAQS in the State. If EPA makes such a finding, EPA is authorized to directly regulate the affected sources. Section 126 relies on the same statutory provision that underlies the CAIR.

In the January 30, 2004 CAIR proposal, EPA set forth its general view of the approach it expected to take in responding to any section 126 petition that might be submitted which relies on essentially the same record as the CAIR. That approach is the one EPA used in addressing section 126 petitions that were submitted to EPA in 1997 while EPA was developing the NO_X SIP Call to control ozone transport. In the NO_X SIP Call rule, we determined under section 110(a)(2)(D) that the SIP for each affected State (and the District of Columbia) must be revised to eliminate the amount of emissions that contributes significantly to nonattainment in downwind States. The emissions reductions requirement was based on the quantity of emissions that could be eliminated by the application of highly cost-effective controls on specified sources in that State. In May 1999, shortly after promulgation of the NO_X SIP Call, EPA took final action on the section 126 petitions (64 FR 28250; May 25, 1999). The Section 126 action relied on essentially the same record as the NO_X SIP Call. In addition, we established a section 126 remedy based on the same set of highly cost-effective controls. In the May 1999 Section 126 Rule, we determined which petitions had technical merit, but we stopped short of granting the findings for the petitions. Instead, we stated that because we had promulgated the NO_X SIP Call—a transport rule under section 110(a)(2)(D)—as long as an upwind State remained on track to comply with that rule, EPA would defer making the section 126 findings. The findings would be triggered at either of two future dates if specified progress had not been made by those times. The Section 126 Rule included a provision under which the rule would be automatically withdrawn for sources in a State once that State submitted and EPA fully approved a SIP that complied with the NO_X SIP Call. (See 64 FR 28271–28274; May 25, 1999.) The reason for this withdrawal would be the fact that the affected State's SIP revision would fulfill the section 110(a)(2)(D) requirements, so that there would no longer be any basis for the section 126 finding with respect to that State. In this manner, the NO_X SIP Call and the Section 126 Rules would be harmonized.

Under the CAIR proposal, EPA received comments regarding its intended approach for acting on any future section 126 petitions that might be filed. Many commenters expressed support for the approach that EPA had outlined. Other commenters raised issues regarding the timing of emissions reductions under a new section 126 action. Some pointed out that the CAIR compliance date would be later than the 3 years allowed for compliance under section 126. Some were concerned that the proposed CAIR compliance date is later than many attainment dates and States may need section 126 petitions in order to get earlier upwind reductions in order to meet their attainment dates. Some questioned the legal basis for linking the two rules. Several commenters expressed concern that EPA would be restricting the use of or weakening the section 126 provision. A number of commenters urged EPA not to prejudge any petition, but to evaluate each on its own merit. Some thought that any petitions submitted prior to designations or before States had had the opportunity to prepare SIPs would be premature and should be denied. Others suggested that CAIR might not solve all the transport problems and that States would need to retain the section 126 tool to seek further reductions.

After issuing the CAIR proposal, EPA received, on March 19, 2004, a section 126 petition from North Carolina seeking reductions in upwind NO_X and SO_2 for purposes of reducing $PM_{2.5}$ and 8-hour ozone levels in North Carolina. The petition relies in large part on the technical record for the proposed CAIR.

When we propose action on the North Carolina petition, we will set forth our view of the interaction between section 110(a)(2)(D) and section 126. In that proposal, we will take into consideration and respond to the section 126-related comments we received on the CAIR. The EPA will provide a comment period and opportunity for a public hearing on the specifics of that section 126 proposal, including an opportunity to comment on our view of the interaction of the 2 statutory provisions.

[167] Eastern Class I areas are those in the CAIR affected states, except areas in west Texas which are considered western and therefore included in the national average, plus those in New England.

E. Will Sources Subject to CAIR Also Be Subject to New Source Review?

The EPA did not propose any provisions in the CAIR related to new source review (NSR). Nonetheless, we received some comments on the relationship between CAIR and the NSR provisions that may apply to emissions sources also impacted by the CAIR. Many commenters indicated that if an EGU is part of an EPA-administered regional cap and trade program for NO_X and SO_2, then that EGU should be exempted from NSR for the covered pollutants. The commenters cited Clear Skies legislation as containing provisions affecting NSR for covered sources. In this final rule, EPA is not addressing or revising the provisions of NSR.

It should be noted that pollution control measures implemented by EGUs in compliance with the CAIR may be eligible for an exemption under the NSR pollution control project provision.[168] These provisions provide an exemption from major NSR for controls such as selective catalytic reduction (SCR) for NO_X control and wet scrubbers for SO_2 control, provided that certain conditions identified in the provisions are met.

X. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

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

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

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

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

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

In view of its important policy implications and potential effect on the economy of over $100 million, this action has been judged to be an economically ''significant regulatory action'' within the meaning of the Executive Order. As a result, today's action was submitted to OMB for review, and EPA has prepared an economic analysis of the rule entitled ''Regulatory Impact Analysis of the Final Clean Air Interstate Rule'' (March 2005).

1. What Economic Analyses Were Conducted for the Rulemaking?

The analyses conducted for this final rule provide several important analyses of impacts on public welfare. These include an analysis of the social benefits, social costs, and net benefits of the regulatory scenario. The economic analyses also address issues involving small business impacts, unfunded mandates (including impacts for Tribal governments), environmental justice, children's health, energy impacts, and requirements of the Paperwork Reduction Act (PRA).

2. What Are the Benefits and Costs of This Rule?

The benefit-cost analysis shows that substantial net economic benefits to society are likely to be achieved due to reductions in emissions resulting from this rule. The results detailed below show that this rule would be highly beneficial to society, with annual net benefits (benefits less costs) of approximately $71.4 or $60.4 billion in 2010 and $98.5 or $83.2 billion in 2015. These alternative net benefits estimates occur due to differing assumptions concerning the social discount rate used to estimate the annual value of the benefits and costs of the rule with the lower estimates relating to a discount rate of 7 percent and the higher estimates a discount rate of 3 percent. All amounts are reflected in 1999 dollars.

The benefits and costs reported for the CAIR represent estimates for the final CAIR program that includes the CAIR promulgated rule and the concurrent proposal to include annual SO_2 and NO_X controls for New Jersey and Delaware. The modeling used to provide these estimates also assumes annual SO_2 and NO_X controls for Arkansas that are not a part of the final CAIR program resulting in a slight overstatement of the reported benefits and costs.

a. Control Scenario

Today's rule sets forth requirements for States to eliminate their significant contribution to down-wind nonattainment of the ozone and $PM_{2.5}$ NAAQS. In order to reduce this significant contribution, EPA requires that certain States reduce their emissions of SO_2 and NO_X. The EPA derived the quantities by calculating the amount of SO_2 and NO_X emissions that EPA believes can be controlled from the electric power industry in a highly cost-effective manner. The EPA considered all promulgated CAA requirements and known State actions in the baseline used to develop the estimates of benefits and costs for this rule. For a more complete description of the reduction requirements and how they were calculated, see section IV of today's rulemaking.

Although States may choose to obtain the emissions reductions from other source categories, for purposes of analyzing the impacts of the rule, EPA is assuming the application of the controls that it has identified to be highly cost effective on all EGUs in the transport region.

b. Cost Analysis and Economic Impacts

For the affected region, the projected annual private incremental costs of the CAIR to the power industry are $2.4 billion in 2010 and $3.6 billion in 2015. These costs represent the private compliance cost to the electric generating industry of reducing NO_X and SO_2 emissions to meet the caps set forth in the rule. Estimates are in 1999 dollars.

In estimating the net benefits of regulation, the appropriate cost measure is ''social costs.'' Social costs represent the welfare costs of the rule to society. These costs do not consider transfer payments (such as taxes) that are simply redistributions of wealth. The social costs of this rule are estimated to be approximately $1.9 billion in 2010 and $2.6 billion in 2015 assuming a 3 percent discount rate. These costs become $2.1 billion in 2010 and $3.1 billion in 2015 assuming a 7 percent discount rate.

Overall, the impacts of the CAIR are modest, particularly in light of the large benefits we expect. Ultimately, we believe the industry will pass along most of the costs of the rule to consumers, so that the costs of the rule will largely fall upon the consumers of electricity. Retail electricity prices are projected to increase roughly 2.0–2.7 percent with the CAIR in the 2010 and 2015 timeframe, and then drop below the 2.0 percent increase level thereafter. The effects of the CAIR on natural gas prices and the power-sector generation mix are relatively small, with a 1.6 percent or less increase in natural gas prices projected from 2010 to 2020.

[168] See 40 CFR 51.165(a)(1)(xxv) and 51.165(e), 40 CFR 51.166(b)(31) and 51.166(v), and 40 CFR 51.21(b)(32) and 52.21(z).

There will be continued reliance on coal-fired generation, that is projected to remain at roughly 50 percent of total electricity generated. A relatively small amount of coal-fired capacity, about 5.3 GW (1.7 percent of all coal-fired capacity and 0.5 percent of all generating capacity), is projected to be uneconomic to maintain. For the most part, these units are small and infrequently used generating units that are dispersed throughout the CAIR region. Units projected to be uneconomic to maintain may be ''mothballed,'' retired, or kept in service to ensure transmission reliability in certain parts of the grid. The EPA's analysis does not address these choices.

As demand grows in the future, additional coal-fired generation is projected to be built under the CAIR. As a result, coal production for electricity generation is projected to increase from 2003 levels by about 15 percent in 2010 and 25 percent by 2020, and we expect a small shift towards greater coal production in Appalachia and the interior coal regions of the country with the CAIR.

For today's rule, EPA analyzed the costs using the Integrated Planning Model (IPM). The IPM is a dynamic linear programming model that can be used to examine the economic impacts of air pollution control policies for SO_2 and NO_X throughout the contiguous U.S. for the entire power system. Documentation for IPM can be found in the docket for this rulemaking or at *http://www.epa.gov/airmarkets/epa-ipm*.

c. Human Health Benefit Analysis

Our analysis of the health and welfare benefits anticipated from this rule are presented in this section. Briefly, the analysis projects major benefits from implementation of the rule in 2010 and 2015. As described below, thousands of deaths and other serious health effects would be prevented. We are able to monetize annual benefits of approximately $73.3 or $62.6 billion in 2010 (based upon a 3 percent or 7 percent discount rate, respectively) and $101 billion or $86.3 billion in 2015 (based upon a discount rate of 3 percent or 7 percent, respectively, 1999 dollars).

Table X–1 presents the primary estimates of reduced incidence of PM- and ozone-related health effects for the years 2010 and 2015 for the regulatory control strategy. In 2015, we estimate that PM-related annual benefits include approximately 17,000 fewer premature fatalities, 8,700 fewer cases of chronic bronchitis, 22,000 fewer non-fatal heart attacks, 10,500 fewer hospitalizations (for respiratory and cardiovascular disease combined) and result in significant reductions in days of restricted activity due to respiratory illness (with an estimate of 9.9 million fewer cases) and approximately 1,700,000 fewer work-loss days. We also estimate substantial health improvements for children from reduced upper and lower respiratory illness, acute bronchitis, and asthma attacks.

Ozone health-related benefits are expected to occur during the summer ozone season (usually ranging from May to September in the Eastern U.S.). Based upon modeling for 2015, annual ozone-related health benefits are expected to include 2,800 fewer hospital admissions for respiratory illnesses, 280 fewer emergency room admissions for asthma, 690,000 fewer days with restricted activity levels, and 510,000 fewer days where children are absent from school due to illnesses.

While we did not include in our primary benefits analysis separate estimates of the number of premature deaths that would be avoided due to reductions in ozone levels, recent studies suggest a link between short-term ozone exposures with premature mortality independent of PM exposures. Based upon a recent report by Thurston and Ito, (2001),[169] the EPA Science Advisory Board has recommended that EPA reevaluate the ozone mortality literature for possible inclusion of ozone mortality in the estimate of total benefits. More recently, a comprehensive analysis using data from the National Morbidity, Mortality and Air Pollution Study (NMMAPS) found a significant association between daily ozone levels and daily mortality rates (Bell *et al.* 2004).[170] The analysis estimated a 0.5 percent increase in daily mortality associated with a 10 ppb increase in ozone, based on data from 95 major urban areas. Using a similar magnitude effect estimate, sensitivity analysis estimates suggest that in 2015, the CAIR would result in an additional 500 fewer premature deaths annually due to reductions in daily ambient ozone concentrations. The EPA has sponsored three independent meta-analyses of the ozone mortality epidemiology literature to inform a determination on inclusion of this important health impact in the primary benefits analysis for future regulations.

Table X–2 presents the estimated monetary value of reductions in the incidence of health and welfare effects. Annual PM-related and ozone-related health benefits are estimated to be approximately $72.1 or $61.4 billion in 2010 (3 percent and 7 percent discount rate, respectively) and $99.3 or $84.5 billion in 2015 (3 percent or 7 percent discount rate, respectively). Estimated annual visibility benefits in southeastern Class I areas are approximately $1.14 billion in 2010 and $1.78 billion in 2015. All monetized estimates are stated in 1999$. These estimates account for growth in real gross domestic product (GDP) per capita between the present and the years 2010 and 2015. As the table indicates, total benefits are driven primarily by the reduction in premature fatalities each year, that accounts for over 90 percent of total benefits.

Table X–3 presents the total monetized net benefits for the years 2010 and 2015. This table also indicates with a ''B'' those additional health and environmental benefits of the rule that we were unable to quantify or monetize. These effects are additive to the estimate of total benefits. A listing of the benefit categories that could not be quantified or monetized in our benefit estimates are provided in Table X–4. We are not able to estimate the magnitude of these unquantified and unmonetized benefits. While EPA believes there is considerable value to the public for the PM-related benefit categories that could not be monetized, we believe these benefits may be small relative to those categories we were able to quantify and monetize. In contrast, EPA believes the monetary value of the ozone-related premature mortality benefits could be substantial. As previously discussed, we estimate that ozone mortality benefits may yield as many as 500 reduced premature mortalities per year and may increase the benefits of CAIR by approximately $3 billion annually.

d. Quantified and Monetized Welfare Benefits

Only a subset of the expected visibility benefits—those for Class I areas in the southeastern U.S. are included in the monetary benefits estimates we project for this rule. We believe the benefits associated with these non-health benefit categories are likely significant. For example, we are able to quantify significant visibility improvements in Class I areas in the Northeast and Midwest, but are unable at present to place a monetary value on these improvements. Similarly, we

[169] Thurston, G.D. and K. Ito. 2001. ''Epidemiological Studies of Acute Ozone Exposures and Mortality''. *J. Expo Anal Environ Epidemiology* 11 (4) :286–294.

[170] Bell, M.L., A. McDermott, S. Zeger, J. Samet, F. Dominichi. 2005. ''Ozone and Mortality in 95 U.S. Urban Communities from 1987 to 2000.'' *Journal of the American Medical Association.* Forthcoming.

anticipate improvement in visibility in residential areas where people live, work and recreate within the CAIR region for which we are currently unable to monetize benefits. For the Class I areas in the southeastern U.S., we estimate annual benefits of $1.78 billion beginning in 2015 for visibility improvements. The value of visibility benefits in areas where we were unable to monetize benefits could also be substantial.

We also quantify nitrogen and sulfur deposition reductions expected to occur as a result of the CAIR and discuss potential benefits from these reductions in section X.A.4 of this preamble. While we are unable to estimate a dollar value associated with these benefits, we are able to quantify acidification improvements in lakes in the Northeast including the Adirondacks and potential benefits of reductions in nitrogen deposition to estuaries such as the Chesapeake Bay.

TABLE X–1.—ESTIMATED ANNUAL REDUCTIONS IN INCIDENCE OF HEALTH EFFECTS [a]

Health Effect	2010 annual incidence reduction	2015 annual incidence reduction
PM–Related endpoints		
Premature Mortality [b, c].		
Adult, age 30 and over	13,000	17,000
Infant, age <1 year	29	36
Chronic bronchitis (adult, age 26 and over)	6,900	8,700
Non-fatal myocardial infarction (adult, age 18 and over)	17,000	22,000
Hospital admissions—respiratory (all ages) [d]	4,300	5,500
Hospital admissions—cardiovascular (adults, age >18) [e]	3,800	5,000
Emergency room visits for asthma (age 18 years and younger)	10,000	13,000
Acute bronchitis, (children, age 8–12)	16,000	19,000
Lower respiratory symptoms (children, age 7–14)	190,000	230,000
Upper respiratory symptoms (asthmatic children, age 9–18)	150,000	180,000
Asthma exacerbation (asthmatic children, age 6–18)	240,000	290,000
Work Loss Days	1,400,000	1,700,000
Minor restricted activity days (adults age 18–65)	8,100,000	9,900,000
Ozone-Related endpoints		
Hospital admissions—respiratory causes (adult, 65 and older) [f]	610	1,700
Hospital admissions—respiratory causes (children, under 2)	380	1,100
Emergency room visit for asthma (all ages)	100	280
Minor restricted activity days (adults, age 18–65)	280,000	690,000
School absence days	180,000	510,000

[a] Incidences are rounded to two significant digits. These estimates represent benefits from the CAIR nationwide. The modeling used to derive these incidence estimates are reflective of those expected for the final CAIR program including the CAIR promulgated rule and the proposal to include annual SO_2 and NO_X controls for New Jersey and Delaware. Modeling used to develop these estimates assumes annual SO_2 and NO_X controls for Arkansas resulting in a slight overstatement of the reported benefits and costs for the complete CAIR program.

[b] Premature mortality benefits associated with ozone are not analyzed in the primary analysis.

[c] Adult mortality based upon studies by Pope, *et al.* 2002.[171] Infant mortality based upon studies by Woodruff, Grillo, and Schoendorf,1997.[172]

[d] Respiratory hospital admissions for PM include admissions for chronic obstructive pulmonary disease (COPD), pneumonia and asthma.

[e] Cardiovascular hospital admissions for PM include total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.

[f] Respiratory hospital admissions for ozone include admissions for all respiratory causes and subcategories for COPD and pneumonia.

TABLE X–2.—ESTIMATED ANNUAL MONETARY VALUE OF REDUCTIONS IN INCIDENCE OF HEALTH AND WELFARE EFFECTS

[Millions of 1999$] [a, b]

Health effect	Pollutant	2010 estimated value of reductions	2015 estimated value of reductions
Premature mortality [c, d]			
Adult >30 years			
3 percent discount rate	$PM_{2.5}$	$67,300	$92,800
7 percent discount rate		56,600	78,100
Child <1 year		168	222
Chronic bronchitis (adults, 26 and over)	$PM_{2.5}$	2,520	3,340
Non-fatal acute myocardial infarctions			
3 percent discount rate	$PM_{2.5}$	1,420	1,850
7 percent discount rate		1,370	1,790

[171] Pope, C.A., III, R.T. Burnett, M.J. Thun, E.E. Calle, D. Krewski, K. Ito, and G.D. Thurston. 2002. ''Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution.'' *Journal of American Medical Association* 287:1132–1141.

[172] Woodruff, T.J., J. Grillo, and K.C. Schoendorf. 1997. ''The Relationship Between Selected Causes of Postneonatal Infant Mortality and Particulate Infant Mortality and Particulate Air Pollution in the United States.'' *Environmental Health Perspectives* 105(6):608–612.

[173] U.S. Environmental Protection Agency, 2000. Guidelines for Preparing Economic Analyses. *www.yosemite1.epa.gov/ee/epa/eed/hsf/pages/Guideline.html.* Office of Management and Budget, The Executive Office of the President, 2003. Circular A–4. *http://www.whitehouse.gov/omb/circulars.*

TABLE X–2.—ESTIMATED ANNUAL MONETARY VALUE OF REDUCTIONS IN INCIDENCE OF HEALTH AND WELFARE EFFECTS—Continued

[Millions of 1999$] [a, b]

Health effect	Pollutant	2010 estimated value of reductions	2015 estimated value of reductions
Hospital admissions for respiratory causes	$PM_{2.5}$, O3	45.2	78.9
Hospital admissions for cardiovascular causes	$PM_{2.5}$	80.7	105
Emergency room visits for asthma	$PM_{2.5}$, O3	2.84	3.56
Acute bronchitis (children, age 8–12)	$PM_{2.5}$	5.63	7.06
Lower respiratory symptoms (children, age 7–14)	$PM_{2.5}$	2.98	3.74
Upper respiratory symptoms (asthma, age 9–11)	$PM_{2.5}$	3.80	4.77
Asthma exacerbations	$PM_{2.5}$	10.3	12.7
Work loss days	$PM_{2.5}$,	180	219
Minor restricted activity days (MRADs)	$PM_{2.5}$, O3	422	543
School absence days	O3	12.9	36.4
Worker productivity (outdoor workers, age 18–65)	O3	7.66	19.9
Recreational visibility, 81 Class I areas	$PM_{2.5}$	1,140	1,780
Monetized Total [e]			
Base estimate			
3 percent discount rate	$PM_{2.5}$, O3	73,300 + B	101,000 + B
7 percent discount rate		62,600 + B	86,300 + B

[a] Monetary benefits are rounded to three significant digits. These estimates represent benefits from the CAIR nationwide for NO_X and SO_2 emissions reductions from electricity-generating units sources (with the exception of ozone and visibility benefits). Ozone benefits relate to the eastern United States. Visibility benefits relate to Class I areas in the southeastern United States. The benefit estimates reflected relate to the final CAIR program that includes the CAIR promulgated rule and the proposal to include annual SO_2 and NO_X controls for New Jersey and Delaware. Modeling used to develop these estimates assumes annual SO_2 and NO_X controls for Arkansas resulting in a slight overstatement of the reported benefits and costs for the complete CAIR program.

[b] Monetary benefits adjusted to account for growth in real GDP per capita between 1990 and the analysis year (2010 or 2015).

[c] Valuation assumes discounting over the SAB recommended 20 year segmented lag structure described in the Regulatory Impact Analysis for the Final Clean Air Interstate Rule (March 2005). Results show 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (US EPA, 2000 and OMB, 2003).[173]

[d] Adult mortality based upon studies by Pope *et al.* 2002. Infant mortality based upon studies by Woodruff, Grillo, and Schoendorf, 1997.

[e] B represents the monetary value of health and welfare benefits not monetized. A detailed listing is provided in Table X–4.

3. How Do the Benefits Compare to the Costs of This Final Rule?

The estimated annual private costs to implement the emission reduction requirements of the final rule for the CAIR region are $2.36 in 2010 and $3.57 billion in 2015 (1999$). These costs are the annual incremental electric generation production costs that are expected to occur with the CAIR. The EPA uses these costs as compliance cost estimates in developing cost-effectiveness estimates.

In estimating the net benefits of regulation, the appropriate cost measure is ''social costs.'' Social costs represent the welfare costs of the rule to society. These costs do not consider transfer payments (such as taxes) that are simply redistributions of wealth. The social costs of this rule are estimated to be approximately $1.9 billion in 2010 and $2.6 billion in 2015 assuming a 3 percent discount rate. These costs become $2.1 billion in 2010 and $3.1 billion in 2015, if one assumes a 7 percent discount rate. Thus, the net benefit (social benefits minus social costs) of the program is approximately $71.4 + B billion or $60.4 + B billion (3 percent and 7 percent discount rate, respectively) annually in 2010 and $98.5 + B billion or $83.2 + B billion annually (3 percent and 7 percent discount rate, respectively) in 2015. Implementation of the rule is expected to provide society with a substantial net gain in social welfare based on economic efficiency criteria.

The annualized regional cost of the CAIR, as quantified here, is EPA's best assessment of the cost of implementing the CAIR, assuming that States adopt the model cap and trade program. These costs are generated from rigorous economic modeling of changes in the power sector due to the CAIR. This type of analysis using IPM has undergone peer review and been upheld in Federal courts. The direct cost includes, but is not limited to, capital investments in pollution controls, operating expenses of the pollution controls, investments in new generating sources, and additional fuel expenditures. The EPA believes that these costs reflect, as closely as possible, the additional costs of the CAIR to industry. The relatively small cost associated with monitoring emissions, reporting, and recordkeeping for affected sources is not included in these annualized cost estimates, but EPA has done a separate analysis and estimated the cost to less than $42 million (see section X. B., Paperwork Reduction Act). However, there may exist certain costs that EPA has not quantified in these estimates. These costs may include costs of transitioning to the CAIR, such as the costs associated with the retirement of smaller or less efficient EGUs, employment shifts as workers are retrained at the same company or re-employed elsewhere in the economy, and certain relatively small permitting costs associated with title IV that new program entrants face. Costs may be understated since an optimization model was employed that assumes cost minimization, and the regulated community may not react in the same manner to comply with the rules. Although EPA has not quantified these costs, the Agency believes that they are small compared to the quantified costs of the program on the power sector. The annualized cost estimates presented are the best and most accurate based upon available information. In a separate analysis, EPA estimates the indirect costs and impacts of higher electricity prices on the entire economy [see Regulatory Impact Analysis for the Final Clean Air Interstate Rule, Appendix E (March 2005)].

The costs presented here are EPA's best estimate of the direct private costs of the CAIR. For purposes of benefit-cost analysis of this rule, EPA has also estimated the additional costs of the CAIR using alternate discount rates for calculating the social costs, parallel to the range of discount rates used in the estimates of the benefits of the CAIR (3 percent and 7 percent). Using these alternate discount rates, the social costs of the CAIR are $1.9 billion in 2010 and $2.6 billion in 2015 using a discount rate of 3 percent, and $2.1 billion in 2010 and $3.1 billion in 2015 using a discount rate of 7 percent. The costs of the CAIR using the adjusted discount rates are lower than the private costs of the CAIR generated using IPM because the social costs do not include certain transfer payments, primarily taxes, that are considered a redistribution of wealth rather than a social cost.[174]

TABLE X–3.—SUMMARY OF ANNUAL BENEFITS, COSTS, AND NET BENEFITS OF THE CLEAN AIR INTERSTATE RULE [a]

[Billions of 1999 dollars]

Description	2010 (Billions of 1999 dollars)	2015 (Billions of 1999 dollars)
Social Costs: [b]		
3 percent discount rate	$1.91	$2.56
7 percent discount rate	2.14	3.07
Social Benefits: [c,d,e]		
3 percent discount rate	73.3 + B	101 + B
7 percent discount rate	62.6 + B	86.3 + B
Health-related benefits:		
3 percent discount rate	72.1 + B	99.3 + B
7 percent discount rate	61.4 + B	84.5 + B
Visibility benefits	1.14 + B	1.78 + B
Annual Net Benefits (Benefits-Costs): [e,f]		
3 percent discount rate	71.4 + B	98.5 + B
7 percent discount rate	60.4 + B	83.2 + B

[a] All estimates are rounded to three significant digits and represent annualized benefits and costs anticipated for the years 2010 and 2015. Estimates relate to the complete CAIR program including the CAIR promulgated rule and the proposal to include annual SO_2 and NO_X controls for New Jersey and Delaware. Modeling used to develop these estimates assumes annual SO_2 and NO_X controls for Arkansas resulting in a slight overstatement of the reported benefits and costs for the complete CAIR program.

[b] Note that costs are the annual total costs of reducing pollutants including NO_X and SO_2 in the CAIR region.

[c] As this table indicates, total benefits are driven primarily by PM-related health benefits. The reduction in premature fatalities each year accounts for over 90 percent of total monetized benefits in 2015. Benefits in this table are nationwide (with the exception of ozone and visibility) and are associated with NO_X and SO_2 reductions for the EGU source category. Ozone benefits represent benefits in the eastern United States. Visibility benefits represent benefits in Class I areas in the southeastern United States.

[d] Not all possible benefits or disbenefits are quantified and monetized in this analysis. B is the sum of all unquantified benefits and disbenefits. Potential benefit categories that have not been quantified and monetized are listed in Table X–4.

[e] Valuation assumes discounting over the SAB-recommended 20 year segmented lag structure described in chapter 4 of the Regulatory Impact Analysis for the Clean Air Interstate Rule (March 2005). Results reflect 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (U.S. EPA, 2000 and OMB, 2003).[174]

[f] Net benefits are rounded to the nearest $100 million. Columnar totals may not sum due to rounding.

Every benefit-cost analysis examining the potential effects of a change in environmental protection requirements is limited to some extent by data gaps, limitations in model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Gaps in the scientific literature often result in the inability to estimate quantitative changes in health and environmental effects. Gaps in the economics literature often result in the inability to assign economic values even to those health and environmental outcomes that can be quantified. While uncertainties in the underlying scientific and economics literatures (that may result in overestimation or underestimation of benefits) are discussed in detail in the economic analyses and its supporting documents and references, the key uncertainties which have a bearing on the results of the benefit-cost analysis of this rule include the following:

- EPA's inability to quantify potentially significant benefit categories;
- Uncertainties in population growth and baseline incidence rates;
- Uncertainties in projection of emissions inventories and air quality into the future;
- Uncertainty in the estimated relationships of health and welfare effects to changes in pollutant concentrations including the shape of the C–R function, the size of the effect estimates, and the relative toxicity of the many components of the PM mixture;
- Uncertainties in exposure estimation; and
- Uncertainties associated with the effect of potential future actions to limit emissions.

Despite these uncertainties, we believe the benefit-cost analysis provides a reasonable indication of the expected economic benefits of the rulemaking in future years under a set of reasonable assumptions.

In valuing reductions in premature fatalities associated with PM, we used a value of $5.5 million per statistical life. This represents a central value consistent with a range of values from $1 to $10 million suggested by recent meta-analyses of the wage-risk value of statistical life (VSL) literature.[175]

The benefits estimates generated for this rule are subject to a number of assumptions and uncertainties, that are discussed throughout the Regulatory Impact Analysis document [Regulatory

[174] United States Environmental Protection Agency, 2000. Guidelines for Preparing Economic Analyses. *www.yosemitel.epa.gov/ee/epa/eed/hsf/pages/Guideline.html.* Office of Management and Budget, The Executive Office of the President, 2003. Circular A–4. *http://www.whitehouse.gov/omb/circulars.*

[175] Mrozek, J.R. and L.O. Taylor, *What determines the value of a life? A Meta Analysis,* Journal of Policy Analysis and Management 21(2), pp. 253–270.

Impact Analysis for the Final Clean Air Interstate Rule (March 2005)]. As Table X–2 indicates, total benefits are driven primarily by the reduction in premature fatalities each year. Elaborating on the previous uncertainty discussion, some key assumptions underlying the primary estimate for the premature mortality category include the following:

(1) EPA assumes inhalation of fine particles is causally associated with premature death at concentrations near those experienced by most Americans on a daily basis. Plausible biological mechanisms for this effect have been hypothesized for the endpoints included in the primary analysis and the weight of the available epidemiological evidence supports an assumption of causality.

(2) EPA assumes all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality. This is an important assumption, because the proportion of certain components in the PM mixture produced via precursors emitted from EGUs may differ significantly from direct PM released from automotive engines and other industrial sources, but no clear scientific grounds exist for supporting differential effects estimates by particle type.

(3) EPA assumes the C–R function for fine particles is approximately linear within the range of ambient concentrations under consideration. In the PM Criteria Document, EPA recognizes that for individuals and specific health responses there are likely threshold levels, but there remains little evidence of thresholds for PM-related effects in populations.[176] Where potential threshold levels have been suggested, they are at fairly low levels with increasing uncertainty about effects at lower ends of the $PM_{2.5}$ concentration ranges. Thus, EPA estimates include health benefits from reducing the fine particles in areas with varied concentrations of PM, including both regions that are in attainment with fine particle standard and those that do not meet the standard.

The EPA recognizes the difficulties, assumptions, and inherent uncertainties in the overall enterprise. The analyses upon which the CAIR is based were selected from the peer-reviewed scientific literature. We used up-to-date assessment tools, and we believe the results are highly useful in assessing this rule.

There are a number of health and environmental effects that we were unable to quantify or monetize. A complete benefit-cost analysis of the CAIR requires consideration of all benefits and costs expected to result from the rule, not just those benefits and costs which could be expressed here in dollar terms. A listing of the benefit categories that were not quantified or monetized in our estimate are provided in Table X–4. These effects are denoted by ''B'' in Table X–3 above, and are additive to the estimates of benefits.

4. What Are the Unquantified and Unmonetized Benefits of the CAIR Emissions Reductions?

Important benefits beyond the human health and welfare benefits resulting from reductions in ambient levels of $PM_{2.5}$ and ozone are expected to occur from this rule. These other benefits occur both directly from NO_X and SO_2 emissions reductions, and indirectly through reductions in co-pollutants such as mercury. These benefits are listed in Table X–4. Some of the more important examples include: Reductions in NO_X and SO_2 emissions required by the CAIR will reduce acidification and, in the case of NO_X, eutrophication of water bodies. Reduced nitrate contamination of drinking water is another possible benefit of the rule. This final rule will also reduce acid and particulate deposition that cause damages to cultural monuments, as well as, soiling and other materials damage.

To illustrate the important nature of benefit categories we are currently unable to monetize, we discuss two categories of public welfare and environmental impacts related to reductions in emissions required by the CAIR: Reduced acid deposition and reduced eutrophication of water bodies.

a. What Are the Benefits of Reduced Deposition of Sulfur and Nitrogen to Aquatic, Forest, and Coastal Ecosystems?

Atmospheric deposition of sulfur and nitrogen, more commonly known as acid rain, occurs when emissions of SO_2 and NO_X react in the atmosphere (with water, oxygen, and oxidants) to form various acidic compounds. These acidic compounds fall to earth in either a wet form (rain, snow, and fog) or a dry form (gases and particles). Prevailing winds can transport acidic compounds hundreds of miles, across State borders. Acidic compounds (including small particles such as sulfates and nitrates) cause many negative environmental effects, including acidification of lakes and streams, harm to sensitive forests, and harm to sensitive coastal ecosystems.

i. Acid Deposition and Acidification of Lakes and Streams

The extent of adverse effects of acid deposition on freshwater and forest ecosystems depends largely upon the ecosystem's ability to neutralize the acid. The neutralizing ability [key indicator is termed Acid Neutralizing Capacity (ANC)] depends largely on the watershed's physical characteristics: Geology, soils, and size. Waters that are sensitive to acidification tend to be located in small watersheds that have few alkaline minerals and shallow soils. Conversely, watersheds that contain alkaline minerals, such as limestone, tend to have waters with a high ANC. Areas especially sensitive to acidification include portions of the Northeast (particularly, the Adirondack and Catskill Mountains, portions of New England, and streams in the mid-Appalachian highlands) and southeastern streams.

Some of the impacts of today's rulemaking on acidification of water bodies have been quantified. In particular, this rule will result in improvements in the acid buffering capacity for lakes in the Northeast and Adirondack Mountains. Specifically, 12 percent of Adirondack lakes are projected to be chronically acidic in the base case. However, we project that the CAIR rule will eliminate chronic acidification in lakes in the Adirondack Mountains by 2030. In addition, today's rule is expected to decrease the percentage of chronically acidic lakes throughout Northeast from 6 to 1 percent. However, some lakes in the Adirondacks and New England will continue to experience episodic acidification even after implementation of this rule.

In a recent study,[177] Resources for the Future (RFF) estimates total benefits (*i.e.*, the sum of use and nonuse values) of natural resource improvements for the Adirondacks resulting from a program that would reduce acidification in 40 percent of the lakes in the Adirondacks that were of concern for acidification. While this study requires further evaluation, the RFF study suggests that the benefits of acid deposition reductions for the CAIR are likely to be substantial in terms of the total monetized value for ecological endpoints (although likely small in

[176] U.S. EPA. (2004). Air Quality Criteria for Particulate Matter. Research Triangle Park, NC: National Center for Environmental Assessment—RTP Office; Report No. EPA/600/P–99/002aD.

[177] Banzhaf, Spencer, Dallas Burtraw, David Evans, and Alan Krupnick. ''Valuation of Natural Resource Improvements in the Adirondacks,'' Resources for the Future (RFF), September 2004.

comparison to the estimated premature mortality benefits estimates).

ii. Acid Deposition and Forest Ecosystem Impacts

Current understanding of the effects of acid deposition on forest ecosystems focuses on the effects of ecological processes affecting plant uptake, retention, and cycling of nutrients within forest ecosystems. Recent studies indicate that acid deposition is at least partially responsible for decreases in base cations (calcium, magnesium, potassium, and others) from soils in the northeastern and southeastern United States. Losses of calcium from forest soils and forested watersheds have now been documented as a sensitive early indicator of soil response to acid deposition for a wide range of forest soils in the United States.

In red spruce stands, a clear link exists between acid deposition, calcium supply, and sensitivity to abiotic stress. Red spruce uptake and retention of calcium is impacted by acid deposition in two main ways: Leaching of important stores of calcium from needles and decreased root uptake of calcium due to calcium depletion from the soil and aluminum mobilization. These changes increase the sensitivity of red spruce to winter injuries under normal winter conditions in the Northeast, result in the loss of needles, slow tree growth, and impair the overall health and productivity of forest ecosystems in many areas of the eastern United States. In addition, recent studies of sugar maple decline in the Northeast demonstrate a link between low base cation availability, high levels of aluminum and manganese in the soil, and increased levels of tree mortality due to native defoliating insects.

Although sulfate is the primary cause of base cation leaching, nitrate is a significant contributor in watersheds that are nearly nitrogen saturated. Base cation depletion is a cause for concern because of the role these ions play in surface water acid neutralization and their importance as essential nutrients for tree growth (calcium, magnesium and potassium).

This regulatory action will decrease acid deposition in the transport region and is likely to have positive effects on the health and productivity of forest systems in the region.

iii. Coastal Ecosystems

Since 1990, a large amount of research has been conducted on the impact of nitrogen deposition to coastal waters. Nitrogen is often the limiting nutrient in coastal ecosystems. Increasing the levels of nitrogen in coastal waters can cause significant changes to those ecosystems. In recent decades, human activities have accelerated nitrogen nutrient inputs, causing excessive growth of algae and leading to degraded water quality and associated impairments of estuarine and coastal resources.

Atmospheric deposition of nitrogen is a significant source of nitrogen to many estuaries. The amount of nitrogen entering estuaries due to atmospheric deposition varies widely, depending on the size and location of the estuarine watershed and other sources of nitrogen in the watershed. There are a few estuaries where atmospheric deposition of nitrogen contributes well over 40 percent of the total nitrogen load; however, in most estuaries for which estimates exist, the contribution from atmospheric deposition ranges from 15–30 percent. The area of the country with the highest air deposition rates (30 percent deposition rates) includes many estuaries along the northeast seaboard from Massachusetts to the Chesapeake Bay and along the central Gulf of Mexico coast.

In 1999, National Oceanic and Atmospheric Administration (NOAA) published the results of a 5-year national assessment of the severity and extent of estuarine eutrophication. An estuary is defined as the inland arm of the sea that meets the mouth of a river. The 138 estuaries characterized in the study represent more than 90 percent of total estuarine water surface area and the total number of U.S. estuaries. The study found that estuaries with moderate to high eutrophication represented 65 percent of the estuarine surface area.

Eutrophication is of particular concern in coastal areas with poor or stratified circulation patterns, such as the Chesapeake Bay, Long Island Sound, and the Gulf of Mexico. In such areas, the ''overproduced'' algae tends to sink to the bottom and decay, using all or most of the available oxygen and thereby reducing or eliminating populations of bottom-feeder fish and shellfish, distorting the normal population balance between different aquatic organisms, and in extreme cases, causing dramatic fish kills. Severe and persistent eutrophication often directly impacts human activities. For example, fishery resource losses can be caused directly by fish kills associated with low dissolved oxygen and toxic blooms. Declines in tourism occur when low dissolved oxygen causes noxious smells and floating mats of algal blooms create unfavorable aesthetic conditions. Risks to human health increase when the toxins from algal blooms accumulate in edible fish and shellfish, and when toxins become airborne, causing respiratory problems due to inhalation. According to the NOAA report, more than half of the nation's estuaries have moderate to high expressions of at least one of these symptoms'an indication that eutrophication is well developed in more than half of U.S. estuaries.

This rule is anticipated to reduce nitrogen deposition in the CAIR region. Thus, reductions in the levels of nitrogen deposition will have a positive impact upon current eutrophic conditions in estuaries and coastal areas in the region. While we are unable to monetize the benefits of such reductions, the Chesapeake Bay Program estimated the reduced mass of delivered nitrogen loads likely to result from the CAIR, based upon the CAIR proposal deposition estimates published in January 2004. Atmospheric deposition of nitrogen accounts for a significant portion of the nitrogen loads to the Chesapeake with 28 percent of the nitrogen loads from the watershed coming from air deposition. Based upon the CAIR proposal, nitrogen deposition rates published in the January 2004 proposal, the Chesapeake Bay Program finds that the CAIR will likely reduce the nitrogen loads to the Bay by 10 million pounds per year by 2010.[178] These substantial nitrogen load reductions more than fulfill the EPA's commitment to reduce atmospheric deposition delivered to the Chesapeake Bay by 8 million pounds.

b. Are There Health or Welfare Disbenefits of the CAIR That Have Not Been Quantified?

In contrast to the additional benefits of the rule discussed above, it is also possible that this rule will result in disbenefits in some areas of the region. Current levels of nitrogen deposition in these areas may provide passive fertilization for forest and terrestrial ecosystems where nutrients are a limiting factor and for some croplands.

The effects of ozone and PM on radiative transfer in the atmosphere can also lead to effects of uncertain magnitude and direction on the penetration of ultraviolet light and climate. Ground level ozone makes up a small percentage of total atmospheric ozone (including the stratospheric layer) that attenuates penetration of ultraviolet—b (UVb) radiation to the ground. The EPA's past evaluation of the information indicates that potential disbenefits would be small, variable, and with too many uncertainties to attempt quantification of relatively

[178] Sweeney, Jeff. ''EPA's Chesapeake Bay Program Air Strategy.'' October 26, 2004.

small changes in average ozone levels over the course of a year (EPA, 2005a). The EPA's most recent provisional assessment of the currently available information indicates that potential but unquantifiable benefits may also arise from ozone-related attenuation of UVb radiation (EPA, 2005b). Sulfate and nitrate particles also scatter UVb, which can decrease exposure of horizontal surfaces to UVb, but increase exposure of vertical surfaces. In this case as well, both the magnitude and direction of the effect of reductions in sulfate and nitrate particles are too uncertain to quantify (EPA, 2004). Ozone is a greenhouse gas, and sulfates and nitrates can reduce the amount of solar radiation reaching the earth, but EPA believes that we are unable to quantify any net climate-related disbenefit or benefit associated with the combined ozone and PM reductions in this rule.

TABLE X–4.—UNQUANTIFIED AND NON-MONETIZED EFFECTS OF THE CLEAN AIR INTERSTATE RULE

Pollutant/effects	Effects not included in primary estimates—Changes in:
Ozone Health [a]	Premature mortality [b] Chronic respiratory damage Premature aging of the lungs Non-asthma respiratory emergency room visits Increased exposure to UVb
Ozone Welfare	Yields for –commercial forests –fruits and vegetables –commercial and non-commercial crops Damage to urban ornamental plants Impacts on recreational demand from damaged forest aesthetics Ecosystem functions Increased exposure to UVb
PM Health [c]	Premature mortality—short term exposures [d] Low birth weight Pulmonary function Chronic respiratory diseases other than chronic bronchitis Non-asthma respiratory emergency room visits Exposure to UVb (+/−) [e]
PM Welfare	Visibility in many Class I areas Residential and recreational visibility in non-Class I areas Soiling and materials damage Damage to ecosystem functions Exposure to UVb (+/−) [e]
Nitrogen and Sulfate Deposition Welfare	Commercial forests due to acidic sulfate and nitrate deposition Commercial freshwater fishing due to acidic deposition Recreation in terrestrial ecosystems due to acidic deposition Existence values for currently healthy ecosystems Commercial fishing, agriculture, and forests due to nitrogen deposition Recreation in estuarine ecosystems due to nitrogen deposition Ecosystem functions Passive fertilization
Mercury Health	Incidences of neurological disorders Incidences of learning disabilities Incidences of developmental delays Potential reproductive effects [f] Potential cardiovascular effects,[f] including: –Altered blood pressure regulation [f] –Increased heart rate variability [f] –Myocardial infarction [f]
Mercury Deposition Welfare	Impact on birds and mammals (*e.g.*, reproductive effects) Impacts to commercial, subsistence, and recreational fishing

Notes:

[a] In addition to primary economic endpoints, there are a number of biological responses that have been associated with ozone health effects including increased airway responsiveness to stimuli, inflamation in the lung, acute inflammation and respiratory cell damage, and increased susceptibility to respiratory infection. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[b] Premature mortality associated with ozone is not currently included in the primary analysis. Recent evidence suggests that short-term exposures to ozone may have a significant effect on daily mortality rates, independent of exposure to PM. EPA is currently conducting a series of meta-analyses of the ozone mortality epidemiology literature. EPA will consider including ozone mortality in primary benefits analyses once a peer reviewed methodology is available.

[c] In addition to primary economic endpoints, there are a number of biological responses that have been associated with PM health effects including morphological changes and altered host defense mechanisms. The public health impact of these biological responses may be partly represented by our quantified endpoints.

[d] While some of the effects of short term exposures are likely to be captured in the estimates, there may be premature mortality due to short term exposure to PM not captured in the cohort study upon which the primary analysis is based.

[e] May result in benefits or disbenefits.

[f] These are potential effects as the literature is insufficient.

B. Paperwork Reduction Act

In compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), EPA submitted a proposed Information Collection Request (ICR) (EPA ICR number 2512.01) to the OMB for review and approval on July 19, 2004 (FR 42720–42722). The ICR describes the nature of the information collection and its estimated burden and cost associated with the final rule. In cases where information is already collected by a related program, the ICR takes into account only the additional burden. This situation arises in States that are also subject to requirements of the Consolidated Emissions Reporting Rule (EPA ICR number 0916.10; OMB control number 2060–0088) or for sources that are subject to the Acid Rain Program (EPA ICR number 1633.13; OMB control number 2060–0258) or NO_X SIP Call (EPA ICR number 1857.03; OMB number 2060–0445) requirements.

The EPA solicited comments on specific aspects of the information collection. The purpose of the ICR is to estimate the anticipated monitoring, reporting, and recordkeeping burden estimates and associated costs for States, local governments, and sources that are expected to result from the CAIR.

The recordkeeping and reporting burden to sources resulting from States choosing to participate in a regional cap and trade program are expected to be less than $42 million annually at the time the monitors are implemented. This estimate includes the annualized cost of installing and operating appropriate SO_2 and NO_X emissions monitoring equipment to measure and report the total emissions of these pollutants from affected EGUs serving generators greater than 25 megawatt electrical. The burden to State and local air agencies includes any necessary SIP revisions, performing monitoring certification, and fulfilling audit responsibilities.

In accordance with the Paperwork Reduction Act, on July 19, 2004, an ICR was made available to the public for comment. The 60-day comment period expired September 19, 2004 with no public comments received specific to the ICR.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. § 601 et seq.)(RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (Pub. L. 104–121)(SBREFA), provides that whenever an agency is required to publish a general notice of rulemaking, it must prepare and make available an initial regulatory flexibility analysis, unless it certifies that the rule, if promulgated, will not have ''a significant economic impact on a substantial number of small entities.'' 5 U.S.C. 605(b). 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 that is identified by the North American Industry Classification System (NAICS) Code, as defined by the Small Business Administration (SBA); (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. Table X–5 lists entities potentially impacted by this rule with applicable NAICS code.

X–5.—POTENTIALLY REGULATED CATEGORIES AND ENTITIES

Category	[1] NAICS code	Examples of potentially regulated entities
Industry	221112	Fossil fuel-fired electric utility steam generating units.
Federal government	[2] 221112	Fossil fuel-fired electric utility steam generating units owned by the Federal government.
State/local/Tribal government	[2] 221112	Fossil fuel-fired electric utility steam generating units owned by municipalities.
	921150	Fossil fuel-fired electric utility steam generating units in Indian Country.

[1] North American Industry Classification System.
[2] Federal, State, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

According to the SBA size standards for NAICS code 221112 Utilities-Fossil Fuel Electric Power Generation, a firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours.

Courts have interpreted the RFA to require a regulatory flexibility analysis only when small entities will be subject to the requirements of the rule. *See Michigan* v. *EPA*, 213 F.3d 663, 668–69 (DC Cir., 2000), *cert. den.* 121 S.Ct. 225, 149 L.Ed.2d 135 (2001).

This rule would not establish requirements applicable to small entities. Instead, it would require States to develop, adopt, and submit SIP revisions that would achieve the necessary SO_2 and NO_X emissions reductions, and would leave to the States the task of determining how to obtain those reductions, including which entities to regulate. Moreover, because affected States would have discretion to choose the sources to regulate and how much emissions reductions each selected source would have to achieve, EPA could not predict the effect of the rule on small entities. Although not required by the RFA, the Agency has conducted a small business analysis.

Overall, about 445 MW of total small entity capacity, or 1.0 percent of total small entity capacity in the CAIR region, is projected to be uneconomic to maintain under the CAIR relative to the base case. In practice, units projected to be uneconomic to maintain may be ''mothballed,'' retired, or kept in service to ensure transmission reliability in certain parts of the grid. Our IPM modeling is unable to distinguish between these potential outcomes.

The EPA modeling identified 264 small entities within the CAIR region based upon the definition of small entity outlined above. From this analysis, EPA excluded 189 small entities that were not projected to have at least one unit with a generating capacity of 25 MW or great operating in the base case. Thus, we found that 75 small entities may potentially be affected by the CAIR. Of these 75 small entities, 28 may experience compliance costs in excess of one percent of revenues in 2010, and 46 may in 2015, based on the Agency's assumptions of how the affected States implement control measures to meet their emissions budgets as set forth in this rulemaking. Potentially affected small entities experiencing compliance costs in excess of 1 percent of revenues have some potential for significant impact resulting from implementation of the CAIR. However, it is the Agency's position that because none of the affected entities currently operate in a competitive market environment, they should be able to pass the costs of complying with the CAIR on to rate-payers. Moreover, the decision to include only units greater than 25 MW in size exempts 185 small entities that would otherwise be potentially affected by the CAIR.

Two other points should be considered when evaluating the impact of the CAIR, specifically, and cap and trade programs more generally, on small entities. First, under the CAIR, the cap and trade program is designed such that States determine how NO_X allowances are to be allocated across units. A State that wishes to mitigate the impact of the rule on small entities might choose to allocate NO_X allowances in a manner that is favorable to small entities. Finally, the use of cap and trade in general will limit impacts on small entities relative to a less flexible command-and-control program.

D. Unfunded Mandates Reform Act

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

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

The EPA prepared a written statement for the final rule consistent with the requirements of section 202 of the UMRA. Furthermore, as EPA stated in the rule, EPA is not directly establishing any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments. Thus, EPA is not obligated to develop under section 203 of the UMRA a small government agency plan. Furthermore, in a manner consistent with the intergovernmental consultation provisions of section 204 of the UMRA, EPA carried out consultations with the governmental entities affected by this rule.

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

As noted earlier, however, notwithstanding these issues, EPA prepared for the final rule the statement that would be required by UMRA if its statutory provisions applied, and EPA has consulted with governmental entities as would be required by UMRA. Consequently, it is not necessary for EPA to reach a conclusion as to the applicability of the UMRA requirements.

The EPA conducted an analysis of the economic impacts anticipated from the CAIR for government-owned entities. The modeling conducted using the IPM projects that about 340 MW of municipality-owned capacity (about 0.4 percent of all subdivision, State and municipality capacity in the CAIR region) would be uneconomic to maintain under the CAIR, beyond what is projected in the base case. In practice, however, the units projected to be uneconomic to maintain may be 'mothballed,' retired, or kept in service to ensure transmission reliability in certain parts of the grid. For the most part, these units are small and infrequently used generating units that are dispersed throughout the CAIR region.

The EPA modeling identified 265 State or municipally-owned entities, as well as subdivisions, within the CAIR region. The EPA excluded from the analysis government-owned entities that were not projected to have at least one unit with generating capacity of 25 MW or greater in the base case. Thus, we excluded 184 entities from the analysis. We found that 81 government entities will be potentially affected by CAIR. Of the 81 government entities, 20 may experience compliance costs in excess of 1 percent of revenues in 2010, and 39 may in 2015, based on our assumptions of how the affected States implement control measures to meet their emissions budgets as set forth in this rulemaking.

Government entities projected to experience compliance costs in excess of 1 percent of revenues have some potential for significant impact resulting from implementation of the CAIR. However, as noted above, it is EPA's position that because these government entities can pass on their costs of compliance to rate-payers, they will not be significantly impacted. Furthermore, the decision to include only units greater than 25 MW in size exempts 179 government entities that would otherwise be potentially affected by the CAIR.

The above points aside, potentially adverse impacts of the CAIR on State and municipality-owned entities could be limited by the fact that the cap and trade program is designed such that States determine how NO_X allowances are to be allocated across units. A State that wishes to mitigate the impact of the rule on State or municipality-owned entities might choose to allocate NO_X allowances in a manner that is favorable to these entities. Finally, the use of cap and trade in general will limit impacts on entities owned by small governments relative to a less flexible command-and-control program.

E. Executive Order 13132: Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This rule 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. The CAA establishes the relationship between the Federal Government and the States, and this rule does not impact that relationship. Thus, Executive Order 13132 does not apply to this rule. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicited comment on this rule from State and local officials.

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

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications.'' This rule does not have ''Tribal implications'' as specified in Executive Order 13175.

This rule addresses transport of pollution that are precurors for ozone and $PM_{2.5}$. The CAA provides for States and Tribes to develop plans to regulate emissions of air pollutants within their jurisdictions. The regulations clarify the statutory obligations of States and Tribes that develop plans to implement this rule. The Tribal Authority Rule (TAR) give Tribes the opportunity to develop and implement CAA programs, but it leaves to the discretion of the Tribe whether to develop these programs and which programs, or appropriate elements of a program, the Tribe will adopt.

This rule does not have Tribal implications as defined by Executive Order 13175. It does not have a substantial direct effect on one or more Indian Tribes, because no Tribe has implemented a federally-enforceable air quality management program under the CAA at this time. Furthermore, this rule does not affect the relationship or distribution of power and responsibilities between the Federal Government and Indian Tribes. The CAA and the TAR establish the relationship of the Federal Government and Tribes in developing plans to attain the NAAQS, and this rule does nothing to modify that relationship. Because this rule does not have Tribal implications, Executive Order 13175 does not apply.

If one assumes a Tribe is implementing a Tribal Implementation Plan, today's rule could have implications for that Tribe, but it would not impose substantial direct costs upon the Tribe, nor preempt Tribal law. As provided above, EPA has estimated that the total annual private costs for the rule for the CAIR region as implemented by State, local, and Tribal governments is approximately $2.4 billion in 2010 and $3.6 billion in 2015 (1999$). There are currently very few emissions sources in Indian country that could be affected by this rule and the percentage of Tribal land that will be impacted is very small. For Tribes that choose to regulate sources in Indian country, the costs would be attributed to inspecting regulated facilities and enforcing adopted regulations.

Although Executive Order 13175 does not apply to this rule, EPA consulted with Tribal officials in developing this rule. The EPA has encouraged Tribal input at an early stage. Also, EPA held periodic meetings with the States and the Tribes during the technical development of this rule. Three meetings were held with the Crow Tribe, where the Tribe expressed concerns about potential impacts of the rule on their coal mine operations. In addition, EPA held three calls with Tribal environmental professionals to address concerns specific to the Tribes. These discussions have given EPA valuable information about Tribal concerns regarding the development of this rule. The EPA has provided briefings for Tribal representatives and the newly formed National Tribal Air Association (NTAA), and other national Tribal forums. Input from Tribal representatives has been taken into consideration in development of this rule.

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

Executive Order 13045, ''Protection of Children from Environmental Health 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, Section 5–501 of the Order directs the Agency to evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

This final rule is not subject to the Executive Order, because it does not involve decisions on environmental health or safety risks that may disproportionately affect children. The EPA believes that the emissions reductions from the strategies in this rule will further improve air quality and will further improve children's health.

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

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies shall prepare and submit to the Administrator of the Office of Regulatory Affairs, OMB, a Statement of Energy Effects for certain actions identified as ''significant energy actions.'' Section 4(b) of Executive Order 13211 defines ''significant energy actions'' as ''any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of final rulemaking, and notices of final rulemaking (1) (i) a significant regulatory action under Executive Order 12866 or any successor order, and (ii) likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) designated by the Administrator of the Office of Information and Regulatory Affairs as a ''significant energy action.'' This final rule is a significant regulatory action under Executive Order 12866, and this rule may have a significant adverse effect on the supply, distribution, or use of energy.

If States choose to obtain the emissions reductions required by this rule by regulating EGUs, EPA projects that approximately 5.3 GWs of coal-fired generation may be removed from operation by 2010. In practice, however, the units projected to be uneconomic to maintain may be 'mothballed,' retired, or kept in service to ensure transmission reliability in certain parts of the grid. For the most part, these units are small and infrequently used generating units that are dispersed throughout the CAIR region. Less conservative assumptions regarding natural gas prices or electricity demand would create a greater incentive to keep these units operational. The EPA projects that the average annual electricity price will increase by less than 2.7 percent in the CAIR region and that natural gas prices will increase by less than 1.6 percent. The EPA does not believe that this rule will have any other impacts that exceed the significance criteria.

The EPA believes that a number of features of today's rulemaking serve to reduce its impact on energy supply. First, the optional trading program provides considerable flexibility to the power sector and enables industry to comply with the emission reduction requirements in the most cost-effective manner, thus minimizing overall costs and the ultimate impact on energy supply. The ability to use banked allowances from the existing title IV SO_2 trading program and the NO_X SIP Call Trading Program also provide additional flexibility. Second, the CAIR caps are set in two phases and provide adequate time for EGUs to install pollution controls. For more details concerning energy impacts, see the Regulatory Impact Analysis for the Final Clean Air Interstate Rule (March 2005).

I. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995 (Pub. L. 104–113; 15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory and procurement activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. The NTTAA directs EPA to provide Congress, through annual reports to OMB, with explanations when an agency does not use available and applicable voluntary consensus standards.

This rule would require all sources that participate in the trading program under part 96 to meet the applicable monitoring requirements of part 75. Part 75 already incorporates a number of voluntary consensus standards. Consistent with the Agency's Performance Based Measurement System (PBMS), part 75 sets forth performance criteria that allow the use of alternative methods to the ones set forth in part 75. The PBMS approach is intended to be more flexible and cost-effective for the regulated community; it is also intended to encourage innovation in analytical technology and improved data quality. At this time, EPA is not recommending any revisions to part 75; however, EPA periodically revises the test procedures set forth in part 75. When EPA revises the test procedures set forth in part 75 in the future, EPA will address the use of any new voluntary consensus standards that are equivalent. Currently, even if a test procedure is not set forth in part 75 EPA is not precluding the use of any method, whether it constitutes a voluntary consensus standard or not, as long as it meets the performance criteria specified; however, any alternative methods must be approved through the petition process under Sec. 75.66 before they are used under part 75.

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

Executive Order 12898, ''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations,'' requires Federal agencies to consider the impact of programs, policies, and activities on minority populations and low-income populations. According to EPA guidance,[179] agencies are to assess whether minority or low-income populations face risks or a rate of exposure to hazards that are significant and that ''appreciably exceed or is likely to appreciably exceed the risk or rate to the general population or to the appropriate comparison group.'' (EPA, 1998)

In accordance with Executive Order 12898, the Agency has considered whether this rule may have disproportionate negative impacts on minority or low income populations. The Agency expects this rule to lead to reductions in air pollution and exposures generally. For this reason, negative impacts to these sub-populations that appreciably exceed similar impacts to the general population are not expected.

K. Congressional Review Act

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

L. Judicial Review

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

Any final action related to CAIR is ''nationally applicable'' within the meaning of section 307(b)(1). As an initial matter, through this rule, EPA interprets section 110 of the CAA, a provision which has nationwide applicability. In addition, CAIR applies to 28 States and the District of Columbia. CAIR is also based on a common core of factual findings and analyses concerning the transport of pollutants between the different States subject to it. Finally, EPA has established uniform approvability criteria that would be applied to all States subject to CAIR. For these reasons, the Administrator also is determining that any final action regarding CAIR is of nationwide scope and effect for purposes of section 307(b)(1). Thus, any petitions for review of final actions regarding CAIR must be filed in the Court of Appeals for the District of Columbia Circuit within 60 days from the date final action is published in the **Federal Register**.

List of Subjects

40 CFR Part 51

Administrative practice and procedure, Air pollution control, Intergovernmental relations, Nitrogen oxides, Ozone, Particulate matter, Regional haze, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Parts 72, 73, 74, 77 and 78

Acid rain, Administrative practice and procedure, Air pollution control, Electric utilities, Intergovernmental

[179] U.S. Environmental Protection Agency, 1998. Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analyses. Office of Federal Activities, Washington, DC, April, 1998.

relations, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

40 CFR Part 96

Administrative practice and procedure, Air pollution control, Electric utilities, Nitrogen oxides, Reporting and recordkeeping requirements, Sulfur dioxide.

Dated: March 10, 2005.

Stephen L. Johnson,

Acting Administrator.

■ Title 40, chapter I, of the Code of Federal Regulations is amended as follows:

PART 51—[AMENDED]

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

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

§ 51.121 [Amended]

■ 2. Section 51.121 is amended by adding a new paragraph (r) to read as follows:

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

* * * * *

(r)(1) Notwithstanding any provisions of paragraph (p) of this section, subparts A through I of part 96 of this chapter, and any State's SIP to the contrary, the Administrator will not carry out any of the functions set forth for the Administrator in subparts A through I of part 96 of this chapter, or in any emissions trading program in a State's SIP approved under paragraph (p) of this section, with regard to any ozone season that occurs after September 30, 2008.

(2) Except as provided in § 51.123(bb), a State whose SIP is approved as meeting the requirements of this section and that includes an emissions trading program approved under paragraph (p) of this section must revise the SIP to adopt control measures that satisfy the same portion of the State's NO_X emission reduction requirements under this section as the State projected such emissions trading program would satisfy.

■ 3. Revise § 51.122 of subpart G to read as follows:

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

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

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

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

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

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

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

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

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

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

(i) Inventory year.

(ii) State Federal Information Placement System code.

(iii) County Federal Information Placement System code.

(iv) Federal ID code (plant).

(v) Federal ID code (point).

(vi) Federal ID code (process).

(vii) Federal ID code (stack).

(viii) Site name.

(ix) Physical address.

(x) SCC.

(xi) Pollutant code.

(xii) Ozone season emissions.

(xiii) Area designation.

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

(i) Fuel heat content (annual).

(ii) Fuel heat content (seasonal).

(iii) Source of fuel heat content data.

(iv) Activity throughput (annual).

(v) Activity throughput (seasonal).

(vi) Source of activity/throughput data.

(vii) Spring throughput (%).

(viii) Summer throughput (%).

(ix) Fall throughput (%).

(x) Work weekday emissions.

(xi) Emission factor.

(xii) Source of emission factor.

(xiii) Hour/day in operation.

(xiv) Operations Start time (hour).

(xv) Day/week in operation.

(xvi) Week/year in operation.

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

(i) The data required in paragraphs (c)(1) and (c)(2) of this section.

(ii) X coordinate (longitude).

(iii) Y coordinate (latitude).

(iv) Stack height.

(v) Stack diameter.

(vi) Exit gas temperature.

(vii) Exit gas velocity.

(viii) Exit gas flow rate.

(ix) SIC.

(x) Boiler/process throughput design capacity.

(xi) Maximum design rate.

(xii) Maximum capacity.

(xiii) Primary control efficiency.

(xiv) Secondary control efficiency.

(xv) Control device type.

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

(1) For annual inventories it must include:

(i) Inventory year.

(ii) State FIPS code.

(iii) County FIPS code.

(iv) SCC.

(v) Emission factor.

(vi) Source of emission factor.

(vii) Activity/throughput level (annual).

(viii) Activity throughput level (seasonal).

(ix) Source of activity/throughput data.

(x) Spring throughput (%).

(xi) Summer throughput (%).

(xii) Fall throughput (%).

(xiii) Control efficiency (%).

(xiv) Pollutant code.

(xv) Ozone season emissions.

(xvi) Source of emissions data.

(xvii) Hour/day in operation.

(xviii) Day/week in operation.

(xix) Week/year in operations.

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

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

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

(i) Inventory year.

(ii) State FIPS code.

(iii) County FIPS code.
(iv) SCC.
(v) Emission factor.
(vi) Source of emission factor.
(vii) Activity (this must be reported for both highway and nonroad activity. Submit nonroad activity in the form of hours of activity at standard load (either full load or average load) for each engine type, application, and horsepower range. Submit highway activity in the form of vehicle miles traveled (VMT) by vehicle class on each roadway type. Report both highway and nonroad activity for a typical ozone season weekday day, if the State uses EPA's default weekday/weekend activity ratio. If the State uses a different weekday/weekend activity ratio, submit separate activity level information for weekday days and weekend days.)
(viii) Source of activity data.
(ix) Pollutant code.
(x) Summer work weekday emissions.
(xi) Ozone season emissions.
(xii) Source of emissions data.
(2) [Reserved.]
(f) Approval of ozone season calculation by EPA. Each State must submit for EPA approval an example of the calculation procedure used to calculate ozone season emissions along with sufficient information for EPA to verify the calculated value of ozone season emissions.
(g) *Reporting schedules.* (1) Data collection is to begin during the ozone season one year prior to the State's NO_X SIP Call compliance date.
(2) Reports are to be submitted according to paragraph (b) of this section and the schedule in Table 1. After 2008, trienniel reports are to be submitted every third year and annual reports are to be submitted each year that a trienniel report is not required.

TABLE 1.—SCHEDULE FOR SUBMITTING REPORTS

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

(3) States must submit data for a required year no later than 12 months after the end of the calendar year for which the data are collected.
(h) *Data Reporting Procedures.* When submitting a formal NO_X budget emissions report and associated data, States shall notify the appropriate EPA Regional Office.
(1) States are required to report emissions data in an electronic format to EPA. Several options are available for data reporting. States can obtain information on the current formats at the following Internet address: *http://www.epa.gov/ttn/chief,* by calling the EPA Info CHIEF help desk at (919) 541–1000 or by sending an e-mail to *info.chief@epa.gov.* Because electronic reporting technology continually changes, States are to contact the Emission Inventory Group (EIG) for the latest specific formats.
(2) For annual reporting (not for triennial reports), a State may have sources submit the data directly to EPA to the extent the sources are subject to a trading program that qualifies for approval under § 51.121(q), and the State has agreed to accept data in this format. The EPA will make both the raw data submitted in this format and summary data available to any State that chooses this option.
(i) *Definitions.* As used in this section, the following words and terms shall have the meanings set forth below:
(1) *Annual emissions.* Actual emissions for a plant, point, or process, either measured or calculated.
(2) *Ash content.* Inert residual portion of a fuel.
(3) *Area designation.* The designation of the area in which the reporting source is located with regard to the ozone NAAQS. This would include attainment or nonattainment designations. For nonattainment designations, the classification of the nonattainment area must be specified, *i.e.*, transitional, marginal, moderate, serious, severe, or extreme.
(4) *Boiler design capacity.* A measure of the size of a boiler, based on the reported maximum continuous steam flow. Capacity is calculated in units of MMBtu/hr.
(5) *Control device type.* The name of the type of control device (*e.g.*, wet scrubber, flaring, or process change).
(6) *Control efficiency.* The emissions reduction efficiency of a primary control device, which shows the amount of reductions of a particular pollutant from a process's emissions due to controls or material change. Control efficiency is usually expressed as a percentage or in tenths.
(7) *Day/week in operations.* Days per week that the emitting process operates.
(8) *Emission factor.* Ratio relating emissions of a specific pollutant to an activity or material throughput level.
(9) *Exit gas flow rate.* Numeric value of stack gas flow rate.
(10) *Exit gas temperature.* Numeric value of an exit gas stream temperature.
(11) *Exit gas velocity.* Numeric value of an exit gas stream velocity.
(12) *Fall throughput (%).* Portion of throughput for the 3 fall months (September, October, November). This represents the expression of annual activity information on the basis of four seasons, typically spring, summer, fall, and winter. It can be represented either as a percentage of the annual activity (*e.g.*, production in summer is 40 percent of the year's production), or in terms of the units of the activity (*e.g.*, out of 600 units produced, spring = 150 units, summer = 250 units, fall = 150 units, and winter = 50 units).
(13) *Federal ID code (plant).* Unique codes for a plant or facility, containing one or more pollutant-emitting sources.
(14) *Federal ID code (point).* Unique codes for the point of generation of emissions, typically a physical piece of equipment.
(15) *Federal ID code (stack number).* Unique codes for the point where emissions from one or more processes are released into the atmosphere.
(16) *Federal Information Placement System (FIPS).* The system of unique numeric codes developed by the government to identify States, counties, towns, and townships for the entire United States, Puerto Rico, and Guam.
(17) *Heat content.* The thermal heat energy content of a solid, liquid, or gaseous fuel. Fuel heat content is typically expressed in units of Btu/lb of fuel, Btu/gal of fuel, joules/kg of fuel, etc.
(18) *Hr/day in operations.* Hours per day that the emitting process operates.
(19) *Maximum design rate.* Maximum fuel use rate based on the equipment's or process' physical size or operational capabilities.
(20) *Maximum nameplate capacity.* A measure of the size of a generator which is put on the unit's nameplate by the manufacturer. The data element is reported in megawatts (MW) or kilowatts (KW).
(21) *Mobile source.* A motor vehicle, nonroad engine or nonroad vehicle, where:
(i) Motor vehicle means any self-propelled vehicle designed for transporting persons or property on a street or highway;
(ii) Nonroad engine means an internal combustion engine (including the fuel system) that is not used in a motor vehicle or a vehicle used solely for competition, or that is not subject to standards promulgated under section 111 or section 202 of the CAA;
(iii) Nonroad vehicle means a vehicle that is powered by a nonroad engine and that is not a motor vehicle or a vehicle used solely for competition.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(41) *X coordinate (longitude).* An object's east-west geographical coordinate.

(42) *Y coordinate (latitude).* An object's north-south geographical coordinate.

■ 4. Part 51 is amended by adding § 51.123 to Subpart G to read as follows:

§ 51.123 Findings and requirements for submission of State implementation plan revisions relating to emissions of oxides of nitrogen pursuant to the Clean Air Interstate Rule.

(a)(1) Under section 110(a)(1) of the CAA, 42 U.S.C. 7410(a)(1), the Administrator determines that each State identified in paragraph (c)(1) and (2) of this section must submit a SIP revision to comply with the requirements of section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), through the adoption of adequate provisions prohibiting sources and other activities from emitting NO_X in amounts that will contribute significantly to nonattainment in, or interfere with maintenance by, one or more other States with respect to the fine particles ($PM_{2.5}$) NAAQS.

(2)(a) Under section 110(a)(1) of the CAA, 42 U.S.C. 7410(a)(1), the Administrator determines that each State identified in paragraph (c)(1) and (3) of this section must submit a SIP revision to comply with the requirements of section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), through the adoption of adequate provisions prohibiting sources and other activities from emitting NO_X in amounts that will contribute significantly to nonattainment in, or interfere with maintenance by, one or more other States with respect to the 8-hour ozone NAAQS.

(b) For each State identified in paragraph (c) of this section, the SIP revision required under paragraph (a) of this section will contain adequate provisions, for purposes of complying with section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), only if the SIP revision contains control measures that assure compliance with the applicable requirements of this section.

(c) In addition to being subject to the requirements in paragraphs (b) and (d) of this section:

(1) Alabama, Florida, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin, and the District of Columbia shall be subject to the requirements contained in paragraphs (e) through (cc) of this section;

(2) Georgia, Minnesota, and Texas shall be subject to the requirements in paragraphs (e) through (o) and (cc) of this section; and

(3) Arkansas, Connecticut, Delaware, Massachusetts, and New Jersey shall be subject to the requirements contained in paragraphs (q) through (cc) of this section.

(d)(1) The State's SIP revision under paragraph (a) of this section must be submitted to EPA by no later than September 11, 2006.

(2) The requirements of appendix V to this part shall apply to the SIP revision under paragraph (a) of this section.

(3) The State shall deliver 5 copies of the SIP revision under paragraph (a) of this section to the appropriate Regional Office, with a letter giving notice of such action.

(e) The State's SIP revision shall contain control measures and demonstrate that they will result in compliance with the State's Annual EGU NO_X Budget, if applicable, and achieve the State's Annual Non-EGU NO_X Reduction Requirement, if applicable, for the appropriate periods. The amounts of the State's Annual EGU NO_X Budget and Annual Non-EGU NO_X Reduction Requirement shall be determined as follows:

(1)(i) The Annual EGU NO_X Budget for the State is defined as the total amount of NO_X emissions from all EGUs in that State for a year, if the State meets the requirements of paragraph (a)(1) of this section by imposing control measures, at least in part, on EGUs. If the State imposes control measures under this section on only EGUs, the Annual EGU NO_X Budget for the State shall not exceed the amount, during the indicated periods, specified in paragraph (e)(2) of this section.

(ii) The Annual Non-EGU NO_X Reduction Requirement, if applicable, is defined as the total amount of NO_X emission reductions that the State demonstrates, in accordance with paragraph (g) of this section, it will achieve from non-EGUs during the appropriate period. If the State meets the requirements of paragraph (a)(1) of this section by imposing control measures on only non-EGUs, then the State's Annual Non-EGU NO_X Reduction Requirement shall equal or exceed, during the appropriate periods, the amount determined in accordance with paragraph (e)(3) of this section.

(iii) If a State meets the requirements of paragraph (a)(1) of this section by imposing control measures on both EGUs and non-EGUs, then:

(A) The Annual Non-EGU NO_X Reduction Requirement shall equal or exceed the difference between the amount specified in paragraph (e)(2) of this section for the appropriate period and the amount of the State's Annual EGU NO_X Budget specified in the SIP revision for the appropriate period; and

(B) The Annual EGU NO_X Budget shall not exceed, during the indicated periods, the amount specified in paragraph (e)(2) of this section plus the amount of the Annual Non-EGU NO_X Reduction Requirement under paragraph (e)(1)(iii)(A) of this section for the appropriate period.

(2) For a State that complies with the requirements of paragraph (a)(1) of this section by imposing control measures on only EGUs, the amount of the Annual EGU NO_X Budget, in tons of NO_X per year, shall be as follows, for the indicated State for the indicated period:

State	Annual EGU NO_X budget for 2009–2014 (tons)	Annual EGU NO_X budget for 2015 and thereafter (tons)
Alabama	69,020	57,517
District of Columbia	144	120
Florida	99,445	82,871
Georgia	66,321	55,268
Illinois	76,230	63,525
Indiana	108,935	90,779
Iowa	32,692	27,243
Kentucky	83,205	69,337
Louisiana	35,512	29,593
Maryland	27,724	23,104
Michigan	65,304	54,420
Minnesota	31,443	26,203
Mississippi	17,807	14,839
Missouri	59,871	49,892
New York	45,617	38,014
North Carolina	62,183	51,819
Ohio	108,667	90,556
Pennsylvania	99,049	82,541
South Carolina	32,662	27,219
Tennessee	50,973	42,478
Texas	181,014	150,845
Virginia	36,074	30,062
West Virginia	74,220	61,850
Wisconsin	40,759	33,966

(3) For a State that complies with the requirements of paragraph (a)(1) of this section by imposing control measures on only non-EGUs, the amount of the Annual Non-EGU NO_X Reduction Requirement, in tons of NO_X per year, shall be determined, for the State for 2009 and thereafter, by subtracting the amount of the State's Annual EGU NO_X Budget for the appropriate year, specified in paragraph (e)(2) of this section from the amount of the State's NO_X baseline EGU emissions inventory projected for the appropriate year, specified in Table 5 of ''Regional and State SO_2 and NO_X Budgets'', March 2005 (available at *http://www.epa.gov/cleanairinterstaterule*).

(4)(i) Notwithstanding the State's obligation to comply with paragraph (e)(2) or (3) of this section, the State's SIP revision may allow sources required by the revision to implement control measures to demonstrate compliance using credit issued from the State's compliance supplement pool, as set forth in paragraph (e)(4)(ii) of this section.

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

State	Compliance supplement pool
Alabama	10,166
District of Columbia	0
Florida	8,335
Georgia	12,397
Illinois	11,299
Indiana	20,155
Iowa	6,978
Kentucky	14,935
Louisiana	2,251
Maryland	4,670
Michigan	8,347
Minnesota	6,528
Mississippi	3,066
Missouri	9,044
New York	0
North Carolina	0
Ohio	25,037
Pennsylvania	16,009
South Carolina	2,600
Tennessee	8,944
Texas	772
Virginia	5,134
West Virginia	16,929
Wisconsin	4,898

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

(A) The State may issue credit from compliance supplement pool to sources that are required by the SIP revision to implement NO_X emission control measures and that implement NO_X emission reductions in 2007 and 2008 that are not necessary to comply with any State or federal emissions limitation applicable at any time during such years. Such a source may be issued one credit from the compliance supplement pool for each ton of such emission reductions in 2007 and 2008.

(*1*) The State shall complete the issuance process by January 1, 2010.

(*2*) The emissions reductions for which credits are issued must have been demonstrated by the owners and operators of the source to have occurred during 2007 and 2008 and not to be necessary to comply with any applicable State or federal emissions limitation.

(*3*) The emissions reductions for which credits are issued must have been quantified by the owners and operators of the source:

(*i*) For EGUs and for fossil-fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBut/hr, using emissions data determined in accordance with subpart H of part 75 of this chapter; and

(*ii*) For non-EGUs not described in paragraph (e)(4)(iii)(A)(3)(i) of this section, using emissions data determined in accordance with subpart H of part 75 of this chapter or, if the State demonstrates that compliance with subpart H of part 75 of this chapter is not practicable, determined, to the extent practicable, with the same degree of assurance with which emissions data are determined for sources subject to subpart H of part 75.

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

(B) The State may issue credit from the compliance supplement pool to sources that are required by the SIP revision to implement NO_X emission control measures and whose owners and operators demonstrate a need for an extension, beyond 2009, of the deadline for the source for implementing such emission controls.

(*1*) The State shall complete the issuance process by January 1, 2010.

(*2*) The State shall issue credit to a source only if the owners and operators of the source demonstrate that:

(*i*) For a source used to generate electricity, implementation of the SIP revision's applicable control measures by 2009 would create undue risk for the reliability of the electricity supply. This demonstration must include a showing that it would not be feasible for the owners and operators of the source to obtain a sufficient amount of electricity, to prevent such undue risk, from other electricity generation facilities during the installation of control technology at the source necessary to comply with the SIP revision.

(*ii*) For a source not used to generate electricity, compliance with the SIP revision's applicable control measures by 2009 would create undue risk for the source or its associated industry to a degree that is comparable to the risk described in paragraph (e)(4)(iii)(B)(2)(i) of this section.

(*iii*) This demonstration must include a showing that it would not be possible for the source to comply with applicable control measures by obtaining sufficient credits under paragraph (e)(4)(iii)(A) of this section, or by acquiring sufficient credits from other sources or persons, to prevent undue risk.

(f) Each SIP revision must set forth control measures to meet the amounts specified in paragraph (e) of this section, as applicable, including the following:

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

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

(ii) Procedures for handling violations; and

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

(2)(i) If a State elects to impose control measures on EGUs, then those measures must impose an annual NO_X mass emissions cap on all such sources in the State.

(ii) If a State elects to impose control measures on fossil fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then those measures must impose an annual NO_X mass emissions cap on all such sources in the State.

(iii) If a State elects to impose control measures on non-EGUs other than those described in paragraph (f)(2)(ii) of this section, then those measures must impose an annual NO_X mass emissions cap on all such sources in the State or the State must demonstrate why such emissions cap is not practicable and adopt alternative requirements that ensure that the State will comply with its requirements under paragraph (e) of this section, as applicable, in 2009 and subsequent years.

(g)(1) Each SIP revision that contains control measures covering non-EGUs as part or all of a State's obligation in meeting its requirement under paragraph (a)(1) of this section must demonstrate that such control measures are adequate to provide for the timely compliance with the State's Annual Non-EGU NO_X Reduction Requirement under paragraph (e) of this section and are not adopted or implemented by the State, as of May 12, 2005, and are not adopted or implemented by the Federal government, as of the date of submission of the SIP revision by the State to EPA.

(2) The demonstration under paragraph (g)(1) of this section must include the following, with respect to each source category of non-EGUs for which the SIP revision requires control measures:

(i) A detailed historical baseline inventory of NO_X mass emissions from the source category in a representative year consisting, at the State's election, of 2002, 2003, 2004, or 2005, or an average of 2 or more of those years, absent the control measures specified in the SIP revision.

(A) This inventory must represent estimates of actual emissions based on monitoring data in accordance with subpart H of part 75 of this chapter, if the source category is subject to monitoring requirements in accordance with subpart H of part 75 of this chapter.

(B) In the absence of monitoring data in accordance with subpart H of part 75 of this chapter, actual emissions must be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to subpart H of part 75 of this chapter and using source-specific or source-category-specific assumptions that ensure a source's or source category's actual emissions are not overestimated. If a State uses factors to estimate emissions, production or utilization, or effectiveness of controls or rules for a source category, such factors must be chosen to ensure that emissions are not overestimated.

(C) For measures to reduce emissions from motor vehicles, emission estimates must be based on an emissions model that has been approved by EPA for use in SIP development and must be consistent with the planning assumptions regarding vehicle miles traveled and other factors current at the time of the SIP development.

(D) For measures to reduce emissions from nonroad engines or vehicles, emission estimates methodologies must be approved by EPA.

(ii) A detailed baseline inventory of NO_X mass emissions from the source category in the years 2009 and 2015, absent the control measures specified in the SIP revision and reflecting changes in these emissions from the historical baseline year to the years 2009 and 2015, based on projected changes in the production input or output, population, vehicle miles traveled, economic activity, or other factors as applicable to this source category.

(A) These inventories must account for implementation of any control measures that are otherwise required by final rules already promulgated, as of May 12, 2005, or adopted or implemented by any federal agency, as of the date of submission of the SIP revision by the State to EPA, and must exclude any control measures specified in the SIP revision to meet the NO_X emissions reduction requirements of this section.

(B) Economic and population forecasts must be as specific as possible to the applicable industry, State, and county of the source or source category and must be consistent with both national projections and relevant official planning assumptions, including estimates of population and vehicle miles traveled developed through consultation between State and local transportation and air quality agencies. However, if these official planning assumptions are inconsistent with official U.S. Census projections of population or with energy consumption projections contained in the U.S. Department of Energy's most recent Annual Energy Outlook, then the SIP revision must make adjustments to correct the inconsistency or must demonstrate how the official planning assumptions are more accurate.

(C) These inventories must account for any changes in production method, materials, fuels, or efficiency that are expected to occur between the historical baseline year and 2009 or 2015, as appropriate.

(iii) A projection of NO_X mass emissions in 2009 and 2015 from the source category assuming the same projected changes as under paragraph (g)(2)(ii) of this section and resulting from implementation of each of the control measures specified in the SIP revision.

(A) These inventories must address the possibility that the State's new control measures may cause production or utilization, and emissions, to shift to unregulated or less stringently regulated sources in the source category in the same or another State, and these inventories must include any such amounts of emissions that may shift to such other sources.

(B) The State must provide EPA with a summary of the computations, assumptions, and judgments used to determine the degree of reduction in projected 2009 and 2015 NO_X emissions that will be achieved from the implementation of the new control measures compared to the relevant baseline emissions inventory.

(iv) The result of subtracting the amounts in paragraph (g)(2)(iii) of this section for 2009 and 2015, respectively, from the lower of the amounts in paragraph (g)(2)(i) or (g)(2)(ii) of this section for 2009 and 2015, respectively, may be credited towards the State's Annual Non-EGU NO_X Reduction Requirement in paragraph (e)(3) of this section for the appropriate period.

(v) Each SIP revision must identify the sources of the data used in each estimate and each projection of emissions.

(h) Each SIP revision must comply with § 51.116 (regarding data availability).

(i) Each SIP revision must provide for monitoring the status of compliance with any control measures adopted to meet the State's requirements under paragraph (e) of this section as follows:

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

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

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

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

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

(4)(i) If the SIP revision contains measures to control EGUs, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter.

(ii) If the SIP revision contains measures to control fossil fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter.

(iii) If the SIP revision contains measures to control any other non-EGUs that are not described in paragraph (i)(4)(ii) of this section, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter, or the State must demonstrate why such requirements are not practicable and adopt alternative requirements that ensure that the required emissions reductions will be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to subpart H of part 75 of this chapter.

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

(1) Adopt emissions standards and limitations and any other measures necessary for attainment and maintenance of the State's relevant Annual EGU NO_X Budget or the Annual Non-EGU NO_X Reduction Requirement, as applicable, under paragraph (e) of this section;

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

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

(4)(i) Require owners or operators of stationary sources to install, maintain, and use emissions monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such stationary sources; and

(ii) Make the data described in paragraph (j)(4)(i) of this section available to the public within a reasonable time after being reported and as correlated with any applicable emissions standards or limitations.

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

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

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

(2) Each SIP revision must comply with § 51.240 (regarding general plan requirements).

(m) Each SIP revision must comply with § 51.280 (regarding resources).

(n) Each SIP revision must provide for State compliance with the reporting requirements in § 51.125.

(o)(1) Notwithstanding any other provision of this section, if a State adopts regulations substantively identical to subparts AA through II of part 96 of this chapter (CAIR NO_X Annual Trading Program), incorporates such subparts by reference into its regulations, or adopts regulations that differ substantively from such subparts only as set forth in paragraph (o)(2) of this section, then such emissions trading program in the State's SIP revision is automatically approved as meeting the requirements of paragraph (e) of this section, provided that the State has the legal authority to take such action and to implement its responsibilities under such regulations.

(2) If a State adopts an emissions trading program that differs substantively from subparts AA through II of part 96 of this chapter only as follows, then the emissions trading program is approved as set forth in paragraph (o)(1) of this section.

(i) The State may decline to adopt the CAIR NO_X opt-in provisions of:

(A) Subpart II of this part and the provisions applicable only to CAIR NO_X opt-in units in subparts AA through HH of this part;

(B) Section 96.188(b) of this chapter and the provisions of subpart II of this part applicable only to CAIR NO_X opt-in units under § 96.188(b); or

(C) Section 96.188(c) of this chapter and the provisions of subpart II of this part applicable only to CAIR NO_X opt-in units under § 96.188(c).

(ii) The State may decline to adopt the allocation provisions set forth in subpart EE of part 96 of this chapter and may instead adopt any methodology for allocating CAIR NO_X allowances to individual sources, as follows:

(A) The State's methodology must not allow the State to allocate CAIR NO_X allowances for a year in excess of the amount in the State's Annual EGU NO_X Budget for such year;

(B) The State's methodology must require that, for EGUs commencing operation before January 1, 2001, the State will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31, 2006 for 2009, 2010, and 2011 and by October 31, 2008 and October 31 of each year thereafter for the year after the year of the notification deadline; and

(C) The State's methodology must require that, for EGUs commencing operation on or after January 1, 2001, the State will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31 of the year for which the CAIR NO_X allowances are allocated.

(3) A State that adopts an emissions trading program in accordance with paragraph (o)(1) or (2) of this section is not required to adopt an emissions trading program in accordance with paragraph (aa)(1) or (2) of this section or § 96.124(o)(1) or (2).

(4) If a State adopts an emissions trading program that differs substantively from subparts AA through HH of part 96 of this chapter, other than as set forth in paragraph (o)(2) of this section, then such emissions trading program is not automatically approved as set forth in paragraph (o)(1) or (2) of this section and will be reviewed by the Administrator for approvability in accordance with the other provisions of this section, provided that the NO_X allowances issued under such emissions trading program shall not, and the SIP revision shall state that such NO_X allowances shall not, qualify as CAIR NO_X allowances or CAIR NO_X Ozone Season allowances under any emissions trading program approved under paragraphs (o)(1) or (2) or (aa)(1) or (2) of this section.

(p) [Reserved]

(q) The State's SIP revision shall contain control measures and demonstrate that they will result in compliance with the State's Ozone Season EGU NO_X Budget, if applicable, and achieve the State's Ozone Season Non-EGU NO_X Reduction Requirement, if applicable, for the appropriate periods. The amounts of the State's Ozone Season EGU NO_X Budget and Ozone Season Non-EGU NO_X Reduction Requirement shall be determined as follows:

(1)(i) The Ozone Season EGU NO_X Budget for the State is defined as the total amount of NO_X emissions from all EGUs in that State for an ozone season, if the State meets the requirements of paragraph (a)(2) of this section by imposing control measures, at least in part, on EGUs. If the State imposes control measures under this section on only EGUs, the Ozone Season EGU NO_X Budget for the State shall not exceed the amount, during the indicated periods, specified in paragraph (q)(2) of this section.

(ii) The Ozone Season Non-EGU NO_X Reduction Requirement, if applicable, is defined as the total amount of NO_X emission reductions that the State demonstrates, in accordance with paragraph (s) of this section, it will achieve from non-EGUs during the appropriate period. If the State meets the requirements of paragraph (a)(2) of this section by imposing control measures on only non-EGUs, then the State's Ozone Season Non-EGU NO_X Reduction Requirement shall equal or exceed, during the appropriate periods, the amount determined in accordance with paragraph (q)(3) of this section.

(iii) If a State meets the requirements of paragraph (a)(2) of this section by imposing control measures on both EGUs and non-EGUs, then:

(A) The Ozone Season Non-EGU NO_X Reduction Requirement shall equal or exceed the difference between the amount specified in paragraph (q)(2) of this section for the appropriate period and the amount of the State's Ozone Season EGU NO_X Budget specified in the SIP revision for the appropriate period; and

(B) The Ozone Season EGU NO_X Budget shall not exceed, during the indicated periods, the amount specified in paragraph (e)(2) of this section plus the amount of the Ozone Season Non-EGU NO_X Reduction Requirement under paragraph (q)(1)(iii)(A) of this section for the appropriate period.

(2) For a State that complies with the requirements of paragraph (a)(2) of this section by imposing control measures on only EGUs, the amount of the Ozone Season EGU NO_X Budget, in tons of NO_X per ozone season, shall be as follows, for the indicated State for the indicated period:

State	Ozone season EGU NO_X budget for 2009–2014 (tons)	Ozone season EGU NO_X budget for 2015 and thereafter (tons)
Alabama	32,182	26,818

State	Ozone season EGU NO_X budget for 2009–2014 (tons)	Ozone season EGU NO_X budget for 2015 and thereafter (tons)
Arkansas	11,515	9,596
Connecticut	2,559	2,559
Delaware	2,226	1,855
District of Columbia	112	94
Florida	47,912	39,926
Illinois	30,701	28,981
Indiana	45,952	39,273
Iowa	14,263	11,886
Kentucky	36,045	30,587
Louisiana	17,085	14,238
Maryland	12,834	10,695
Massachusetts	7,551	6,293
Michigan	28,971	24,142
Mississippi	8,714	7,262
Missouri	26,678	22,231
New Jersey	6,654	5,545
New York	20,632	17,193
North Carolina	28,392	23,660
Ohio	45,664	39,945
Pennsylvania	42,171	35,143
South Carolina	15,249	12,707
Tennessee	22,842	19,035
Virginia	15,994	13,328
West Virginia	26,859	26,525
Wisconsin	17,987	14,989

(3) For a State that complies with the requirements of paragraph (a)(2) of this section by imposing control measures on only non-EGUs, the amount of the Ozone Season Non-EGU NO_X Reduction Requirement, in tons of NO_X per ozone season, shall be determined, for the State for 2009 and thereafter, by subtracting the amount of the State's Ozone Season EGU NO_X Budget for the appropriate year, specified in paragraph (e)(2) of this section, from the amount of the State's NO_X baseline EGU emissions inventory projected for the ozone season in the appropriate year, specified in Table 7 of ''Regional and State SO_2 and NO_X Budgets'', March 2005 (available at: *http://www.epa.gov/cleanairinterstaterule*).

(4) Notwithstanding the State's obligation to comply with paragraph (q)(2) or (3) of this section, the State's SIP revision may allow sources required by the revision to implement NO_X emission control measures to demonstrate compliance using NO_X SIP Call allowances allocated under the NO_X Budget Trading Program for any ozone season during 2003 through 2008 that have not been deducted by the Administrator under the NO_X Budget Trading Program, if the SIP revision ensures that such allowances will not be available for such deduction under the NO_X Budget Trading Program.

(r) Each SIP revision must set forth control measures to meet the amounts specified in paragraph (q) of this section, as applicable, including the following:

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

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

(ii) Procedures for handling violations; and

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

(2)(i) If a State elects to impose control measures on EGUs, then those measures must impose an ozone season NO_X mass emissions cap on all such sources in the State.

(ii) If a State elects to impose control measures on fossil fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then those measures must impose an ozone season NO_X mass emissions cap on all such sources in the State.

(iii) If a State elects to impose control measures on non-EGUs other than those described in paragraph (r)(2)(ii) of this section, then those measures must impose an ozone season NO_X mass emissions cap on all such sources in the State or the State must demonstrate why such emissions cap is not practicable and adopt alternative requirements that ensure that the State will comply with its requirements under paragraph (q) of this section, as applicable, in 2009 and subsequent years.

(s)(1) Each SIP revision that contains control measures covering non-EGUs as part or all of a State's obligation in meeting its requirement under paragraph (a)(2) of this section must demonstrate that such control measures are adequate to provide for the timely compliance with the State's Ozone Season Non-EGU NO_X Reduction Requirement under paragraph (q) of this section and are not adopted or implemented by the State, as of May 12, 2005, and are not adopted or implemented by the federal government, as of the date of submission of the SIP revision by the State to EPA.

(2) The demonstration under paragraph (s)(1) of this section must include the following, with respect to each source category of non-EGUs for which the SIP revision requires control measures:

(i) A detailed historical baseline inventory of NO_X mass emissions from the source category in a representative ozone season consisting, at the State's election, of the ozone season in 2002, 2003, 2004, or 2005, or an average of 2 or more of those ozone seasons, absent the control measures specified in the SIP revision.

(A) This inventory must represent estimates of actual emissions based on monitoring data in accordance with subpart H of part 75 of this chapter, if the source category is subject to monitoring requirements in accordance with subpart H of part 75 of this chapter.

(B) In the absence of monitoring data in accordance with subpart H of part 75 of this chapter, actual emissions must be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to subpart H of part 75 of this chapter and using source-specific or source-category-specific assumptions that ensure a source's or source category's actual emissions are not overestimated. If a State uses factors to estimate emissions, production or utilization, or effectiveness of controls or rules for a source category, such factors must be chosen to ensure that emissions are not overestimated.

(C) For measures to reduce emissions from motor vehicles, emission estimates must be based on an emissions model that has been approved by EPA for use in SIP development and must be consistent with the planning assumptions regarding vehicle miles traveled and other factors current at the time of the SIP development.

(D) For measures to reduce emissions from nonroad engines or vehicles, emission estimates methodologies must be approved by EPA.

(ii) A detailed baseline inventory of NO_X mass emissions from the source category in ozone seasons 2009 and 2015, absent the control measures specified in the SIP revision and reflecting changes in these emissions from the historical baseline ozone season to the ozone seasons 2009 and 2015, based on projected changes in the production input or output, population, vehicle miles traveled, economic activity, or other factors as applicable to this source category.

(A) These inventories must account for implementation of any control measures that are adopted or implemented by the State, as of May 12, 2005, or adopted or implemented by the federal government, as of the date of submission of the SIP revision by the State to EPA, and must exclude any control measures specified in the SIP revision to meet the NO_X emissions reduction requirements of this section.

(B) Economic and population forecasts must be as specific as possible to the applicable industry, State, and county of the source or source category and must be consistent with both national projections and relevant official planning assumptions including estimates of population and vehicle miles traveled developed through consultation between State and local transportation and air quality agencies. However, if these official planning assumptions are inconsistent with official U.S. Census projections of population or with energy consumption projections contained in the U.S. Department of Energy's most recent Annual Energy Outlook, then the SIP revision must make adjustments to correct the inconsistency or must demonstrate how the official planning assumptions are more accurate.

(C) These inventories must account for any changes in production method, materials, fuels, or efficiency that are expected to occur between the historical baseline ozone season and ozone season 2009 or ozone season 2015, as appropriate.

(iii) A projection of NO_X mass emissions in ozone season 2009 and ozone season 2015 from the source category assuming the same projected changes as under paragraph (s)(2)(ii) of this section and resulting from implementation of each of the control measures specified in the SIP revision.

(A) These inventories must address the possibility that the State's new control measures may cause production or utilization, and emissions, to shift to unregulated or less stringently regulated sources in the source category in the same or another State, and these inventories must include any such amounts of emissions that may shift to such other sources.

(B) The State must provide EPA with a summary of the computations, assumptions, and judgments used to determine the degree of reduction in projected ozone season 2009 and ozone season 2015 NO_X emissions that will be achieved from the implementation of the new control measures compared to the relevant baseline emissions inventory.

(iv) The result of subtracting the amounts in paragraph (s)(2)(iii) of this section for ozone season 2009 and ozone season 2015, respectively, from the lower of the amounts in paragraph (s)(2)(i) or (s)(2)(ii) of this section for ozone season 2009 and ozone season 2015, respectively, may be credited towards the State's Ozone Season Non-EGU NO_X Reduction Requirement in paragraph (q)(3) of this section for the appropriate period.

(v) Each SIP revision must identify the sources of the data used in each estimate and each projection of emissions.

(t) Each SIP revision must comply with § 51.116 (regarding data availability).

(u) Each SIP revision must provide for monitoring the status of compliance with any control measures adopted to meet the State's requirements under paragraph (q) of this section as follows:

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

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

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

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

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

(4)(i) If the SIP revision contains measures to control EGUs, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter.

(ii) If the SIP revision contains measures to control fossil fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter.

(iii) If the SIP revision contains measures to control any other non-EGUs that are not described in paragraph (u)(4)(ii) of this section, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of subpart H of part 75 of this chapter, or the State must demonstrate why such requirements are not practicable and adopt alternative requirements that ensure that the required emissions reductions will be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to subpart H of part 75 of this chapter.

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

(1) Adopt emissions standards and limitations and any other measures necessary for attainment and maintenance of the State's relevant Ozone Season EGU NO_X Budget or the Ozone Season Non-EGU NO_X Reduction Requirement, as applicable, under paragraph (q) of this section;

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

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

(4)(i) Require owners or operators of stationary sources to install, maintain, and use emissions monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such stationary sources; and

(ii) Make the data described in paragraph (v)(4)(i) of this section available to the public within a reasonable time after being reported and as correlated with any applicable emissions standards or limitations.

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

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

(x)(1) A SIP revision may assign legal authority to local agencies in accordance with § 51.232.

(2) Each SIP revision must comply with § 51.240 (regarding general plan requirements).

(y) Each SIP revision must comply with § 51.280 (regarding resources).

(z) Each SIP revision must provide for State compliance with the reporting requirements in § 51.125.

(aa)(1) Notwithstanding any other provision of this section, if a State adopts regulations substantively identical to subparts AAAA through IIII of part 96 of this chapter (CAIR Ozone Season NO_X Trading Program), incorporates such subparts by reference into its regulations, or adopts regulations that differ substantively from such subparts only as set forth in paragraph (aa)(2) of this section, then such emissions trading program in the State's SIP revision is automatically approved as meeting the requirements of paragraph (q) of this section, provided that the State has the legal authority to take such action and to implement its responsibilities under such regulations.

(2) If a State adopts an emissions trading program that differs substantively from subparts AAAA through IIII of part 96 of this chapter only as follows, then the emissions trading program is approved as set forth in paragraph (aa)(1) of this section.

(i) The State may expand the applicability provisions in § 96.304 to include all non-EGUs subject to the State's emissions trading program approved under § 51.121(p).

(ii) The State may decline to adopt the CAIR NO_X Ozone Season opt-in provisions of:

(A) Subpart IIII of this part and the provisions applicable only to CAIR NO_X Ozone Season opt-in units in subparts AAAA through HHHH of this part;

(B) Section 96.388(b) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(b); or

(C) Section 96.388(c) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(c).

(iii) The State may decline to adopt the allocation provisions set forth in subpart EEEE of part 96 of this chapter and may instead adopt any methodology for allocating CAIR NO_X Ozone Season allowances to individual sources, as follows:

(A) The State may provide for issuance of an amount of CAIR Ozone Season NO_X allowances for an ozone season, in addition to the amount in the State's Ozone Season EGU NO_X Budget for such ozone season, not exceeding the amount of NO_X SIP Call allowances allocated for the ozone season under the NO_X Budget Trading Program to non-EGUs that the applicability provisions in § 96.304 are expanded to include under paragraph (aa)(2)(i) of this section;

(B) The State's methodology must not allow the State to allocate CAIR Ozone Season NO_X allowances for an ozone season in excess of the amount in the State's Ozone Season EGU NO_X Budget for such ozone season plus any additional amount of CAIR Ozone Season NO_X allowances issued under paragraph (aa)(2)(iii)(A) of this section for such ozone season;

(C) The State's methodology must require that, for EGUs commencing operation before January 1, 2001, the State will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31, 2006 for the ozone seasons 2009, 2010, and 2011 and by October 31, 2008 and October 31 of each year thereafter for the ozone season in the 4th year after the year of the notification deadline; and

(D) The State's methodology must require that, for EGUs commencing operation on or after January 1, 2001, the State will determine, and notify the Administrator of, each unit's allocation of CAIR Ozone Season NO_X allowances by July 31 of the calendar year of the ozone season for which the CAIR Ozone Season NO_X allowances are allocated.

(3) A State that adopts an emissions trading program in accordance with paragraph (aa)(1) or (2) of this section is not required to adopt an emissions trading program in accordance with paragraph (o)(1) or (2) of this section or § 51.153(o)(1) or (2).

(4) If a State adopts an emissions trading program that differs substantively from subparts AAAA through IIII of part 96 of this chapter, other than as set forth in paragraph (aa)(2) of this section, then such emissions trading program is not automatically approved as set forth in paragraph (aa)(1) or (2) of this section and will be reviewed by the Administrator for approvability in accordance with the other provisions of this section, provided that the NO_X allowances issued under such emissions trading program shall not, and the SIP revision shall state that such NO_X allowances shall not, qualify as CAIR NO_X allowances or CAIR Ozone Season NO_X allowances under any emissions trading program approved under paragraphs (o)(1) or (2) or (aa)(1) or (2) of this section.

(bb)(1)(i) The State may revise its SIP to provide that, for each ozone season during which a State implements control measures on EGUs or non-EGUs through an emissions trading program approved under paragraph (aa)(1) or (2) of this section, such EGUs and non-EGUs shall not be subject to the requirements of the State's SIP meeting the requirements of § 51.121, if the State meets the requirement in paragraph (bb)(1)(ii) of this section.

(ii) For a State under paragraph (bb)(1)(i) of this section, if the State's amount of tons specified in paragraph (q)(2) of this section exceeds the State's amount of NO_X SIP Call allowances allocated for the ozone season in 2009 or in any year thereafter for the same types and sizes of units as those covered by the amount of tons specified in paragraph (q)(2) of this section, then the State must replace the former amount for such ozone season by the latter amount for such ozone season in applying paragraph (q) of this section.

(2) Rhode Island may revise its SIP to provide that, for each ozone season during which Rhode Island implements control measures on EGUs and non-EGUs through an emissions trading program adopted in regulations that differ substantively from subparts AAAA through IIII of part 96 of this

chapter as set forth in this paragraph, such EGUs and non-EGUs shall not be subject to the requirements of the State's SIP meeting the requirements of § 51.121.

(i) Rhode Island must expand the applicability provisions in § 96.304 to include all non-EGUs subject to Rhode Island's emissions trading program approved under § 51.121(p).

(ii) Rhode Island may decline to adopt the CAIR NO_X Ozone Season opt-in provisions of:

(A) Subpart IIII of this part and the provisions applicable only to CAIR NO_X Ozone Season opt-in units in subparts AAAA through HHHH of this part;

(B) Section 96.388(b) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(b); or

(C) Section 96.388(c) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(c).

(iii) Rhode Island may adopt the allocation provisions set forth in subpart EEEE of part 96 of this chapter, provided that Rhode Island must provide for issuance of an amount of CAIR Ozone Season NO_X allowances for an ozone season not exceeding 936 tons for 2009 and thereafter;

(iv) Rhode Island may adopt any methodology for allocating CAIR NO_X Ozone Season allowances to individual sources, as follows:

(A) Rhode Island's methodology must not allow Rhode Island to allocate CAIR Ozone Season NO_X allowances for an ozone season in excess of 936 tons for 2009 and thereafter;

(B) Rhode Island's methodology must require that, for EGUs commencing operation before January 1, 2001, Rhode Island will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31, 2006 for the ozone seasons 2009, 2010, and 2011 and by October 31, 2008 and October 31 of each year thereafter for the ozone season in the 4th year after the year of the notification deadline; and

(C) Rhode Island's methodology must require that, for EGUs commencing operation on or after January 1, 2001, Rhode Island will determine, and notify the Administrator of, each unit's allocation of CAIR Ozone Season NO_X allowances by July 31 of the calendar year of the ozone season for which the CAIR Ozone Season NO_X allowances are allocated.

(3) Notwithstanding a SIP revision by a State authorized under paragraph (bb)(1) of this section or by Rhode Island under paragraph (bb)(2) of this section, if the State's or Rhode Island's SIP that, without such SIP revision, imposes control measures on EGUs or non-EGUs under § 51.121 is determined by the Administrator to meet the requirements of § 51.121, such SIP shall be deemed to continue to meet the requirements of § 51.121.

(cc) The terms used in this section shall have the following meanings:

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

Allocate or *allocation* means, with regard to allowances, the determination of the amount of allowances to be initially credited to a source.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Clean Air Act or *CAA* means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity—

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

Combustion turbine means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated heat recovery steam generator and steam turbine.

Commence operation means to have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber.

Electric generating unit or *EGU* means:

(1) Except as provided in paragraph (2) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (1) of this definition starting on the day on which the unit first no longer qualifies as a cogeneration unit.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

Generator means a device that produces electricity.

Maximum design heat input means:

(1) Starting from the initial installation of a unit, the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as specified by the manufacturer of the unit;

(2)(i) Except as provided in paragraph (2)(ii) of this definition, starting from the completion of any subsequent physical change in the unit resulting in an increase in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis, such increased maximum amount as specified by the person conducting the physical change; or

(ii) For purposes of applying the definition of the term ''potential electrical output capacity,'' starting from the completion of any subsequent physical change in the unit resulting in a decrease in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis, such decreased maximum amount as specified by the person conducting the physical change.

NAAQS means National Ambient Air Quality Standard.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as specified by the person conducting the physical change.

Non-EGU means a source of NO_X emissions that is not an EGU.

NO_X Budget Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts A through I of this part and § 51.121, as a means of mitigating interstate transport of ozone and nitrogen oxides.

NO_X SIP Call allowance means a limited authorization issued by the Administrator under the NO_X Budget Trading Program to emit up to one ton of nitrogen oxides during the ozone season of the specified year or any year thereafter, provided that the provision in § 51.121(b)(2)(ii)(E) shall not be used in applying this definition.

Ozone season means the period, which begins May 1 and ends September 30 of any year.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself.

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

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

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process, excluding any heat contained in condensate return or makeup water;

(2) Used in a heat application (*e.g.*, space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.*, thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

(dd) New Hampshire may revise its SIP to implements control measures on EGUs and non-EGUs through an emissions trading program adopted in regulations that differ substantively from subparts AAAA through IIII of part 96 of this chapter as set forth in this paragraph.

(1) New Hampshire must expand the applicability provisions in § 96.304 of this chapter to include all non-EGUs subject to New Hampshire's emissions trading program at New Hampshire Code of Administrative Rules, chapter Env-A 3200 (2004).

(2) New Hampshire may decline to adopt the CAIR NO_X Ozone Season opt-in provisions of:

(i) Subpart IIII of this part and the provisions applicable only to CAIR NO_X Ozone Season opt-in units in subparts AAAA through HHHH of this part;

(ii) Section 96.388(b) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(b); or

(iii) Section 96.388(c) of this chapter and the provisions of subpart IIII of this part applicable only to CAIR NO_X Ozone Season opt-in units under § 96.388(c).

(3) New Hampshire may adopt the allocation provisions set forth in subpart EEEE of part 96 of this chapter, provided that New Hampshire must provide for issuance of an amount of CAIR Ozone Season NO_X allowances for an ozone season not exceeding 3,000 tons for 2009 and thereafter;

(4) New Hampshire may adopt any methodology for allocating CAIR NO_X Ozone Season allowances to individual sources, as follows:

(i) New Hampshire's methodology must not allow New Hampshire to allocate CAIR Ozone Season NO_X allowances for an ozone season in excess of 3,000 tons for 2009 and thereafter;

(ii) New Hampshire's methodology must require that, for EGUs commencing operation before January 1, 2001, New Hampshire will determine, and notify the Administrator of, each unit's allocation of CAIR NO_X allowances by October 31, 2006 for the ozone seasons 2009, 2010, and 2011 and by October 31, 2008 and October 31 of each year thereafter for the ozone season in the 4th year after the year of the notification deadline; and

(iii) New Hampshire's methodology must require that, for EGUs commencing operation on or after January 1, 2001, New Hampshire will determine, and notify the Administrator of, each unit's allocation of CAIR Ozone Season NO_X allowances by July 31 of the calendar year of the ozone season for which the CAIR Ozone Season NO_X allowances are allocated.

■ 5. Part 51 is amended by adding § 51.124 to Subpart G to read as follows:

§ 51.124 Findings and requirements for submission of State implementation plan revisions relating to emissions of sulfur dioxide pursuant to the Clean Air Interstate Rule.

(a) Under section 110(a)(1) of the CAA, 42 U.S.C. 7410(a)(1), the Administrator determines that each State identified in paragraph (c) of this section must submit a SIP revision to comply with the requirements of section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), through the adoption of adequate provisions prohibiting sources and other activities from emitting SO_2 in amounts that will contribute significantly to nonattainment in, or interfere with maintenance by, one or more other States with respect to the fine particles ($PM_{2.5}$) NAAQS.

(b) For each State identified in paragraph (c) of this section, the SIP revision required under paragraph (a) of this section will contain adequate provisions, for purposes of complying with section 110(a)(2)(D)(i)(I) of the CAA, 42 U.S.C. 7410(a)(2)(D)(i)(I), only if the SIP revision contains control measures that assure compliance with the applicable requirements of this section.

(c) The following States are subject to the requirements of this section: Alabama, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, and Wisconsin, and the District of Columbia.

(d)(1) The SIP revision under paragraph (a) of this section must be submitted to EPA by no later than September 11, 2006.

(2) The requirements of appendix V to this part shall apply to the SIP revision under paragraph (a) of this section.

(3) The State shall deliver 5 copies of the SIP revision under paragraph (a) of this section to the appropriate Regional Office, with a letter giving notice of such action.

(e) The State's SIP revision shall contain control measures and demonstrate that they will result in compliance with the State's Annual EGU SO_2 Budget, if applicable, and achieve the State's Annual Non-EGU SO_2 Reduction Requirement, if applicable, for the appropriate periods. The amounts of the State's Annual EGU SO_2 Budget and Annual Non-EGU SO_2 Reduction Requirement shall be determined as follows:

(1)(i) The Annual EGU SO_2 Budget for the State is defined as the total amount of SO_2 emissions from all EGUs in that State for a year, if the State meets the requirements of paragraph (a) of this section by imposing control measures, at least in part, on EGUs. If the State imposes control measures under this section on only EGUs, the Annual EGU SO_2 Budget for the State shall not exceed the amount, during the indicated periods, specified in paragraph (e)(2) of this section.

(ii) The Annual Non-EGU SO_2 Reduction Requirement, if applicable, is defined as the total amount of SO_2 emission reductions that the State demonstrates, in accordance with paragraph (g) of this section, it will achieve from non-EGUs during the appropriate period. If the State meets the requirements of paragraph (a) of this section by imposing control measures on only non-EGUs, then the State's Annual Non-EGU SO_2 Reduction Requirement shall equal or exceed, during the appropriate periods, the amount determined in accordance with paragraph (e)(3) of this section.

(iii) If a State meets the requirements of paragraph (a) of this section by imposing control measures on both EGUs and non-EGUs, then:

(A) The Annual Non-EGU SO_2 Reduction Requirement shall equal or exceed the difference between the amount specified in paragraph (e)(2) of this section for the appropriate period and the amount of the State's Annual EGU SO_2 Budget specified in the SIP revision for the appropriate period; and

(B) The Annual EGU SO_2 Budget shall not exceed, during the indicated periods, the amount specified in paragraph (e)(2) of this section plus the amount of the Annual Non-EGU SO_2 Reduction Requirement under paragraph (e)(1)(iii)(A) of this section for the appropriate period.

(2) For a State that complies with the requirements of paragraph (a) of this section by imposing control measures on only EGUs, the amount of the Annual EGU SO_2 Budget, in tons of SO_2 per year, shall be as follows, for the indicated State for the indicated period:

State	Annual EGU SO_2 budget for 2010–2014 (tons)	Annual EGU SO_2 budget for 2015 and thereafter (tons)
Alabama	157,582	110,307
District of Columbia	708	495
Florida	253,450	177,415
Georgia	213,057	149,140
Illinois	192,671	134,869
Indiana	254,599	178,219
Iowa	64,095	44,866
Kentucky	188,773	132,141
Louisiana	59,948	41,963
Maryland	70,697	49,488
Michigan	178,605	125,024
Minnesota	49,987	34,991
Mississippi	33,763	23,634
Missouri	137,214	96,050
New York	135,139	94,597
North Carolina	137,342	96,139
Ohio	333,520	233,464
Pennsylvania	275,990	193,193
South Carolina	57,271	40,089
Tennessee	137,216	96,051
Texas	320,946	224,662
Virginia	63,478	44,435
West Virginia	215,881	151,117
Wisconsin	87,264	61,085

(3) For a State that complies with the requirements of paragraph (a) of this section by imposing control measures on only non-EGUs, the amount of the Annual Non-EGU SO_2 Reduction Requirement, in tons of SO_2 per year, shall be determined, for the State for 2010 and thereafter, by subtracting the amount of the State's Annual EGU SO_2 Budget for the appropriate year, specified in paragraph (e)(2) of this section, from an amount equal to 2 times the State's Annual EGU SO_2 Budget for 2010 through 2014, specified in paragraph (e)(2) of this section.

(f) Each SIP revision must set forth control measures to meet the amounts specified in paragraph (e) of this section, as applicable, including the following:

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

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

(ii) Procedures for handling violations; and

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

(2)(i) If a State elects to impose control measures on EGUs, then those measures must impose an annual SO_2 mass emissions cap on all such sources in the State.

(ii) If a State elects to impose control measures on fossil fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then those measures must impose an annual SO_2 mass emissions cap on all such sources in the State.

(iii) If a State elects to impose control measures on non-EGUs other than those described in paragraph (f)(2)(ii) of this section, then those measures must impose an annual SO_2 mass emissions cap on all such sources in the State, or the State must demonstrate why such emissions cap is not practicable, and adopt alternative requirements that ensure that the State will comply with its requirements under paragraph (e) of this section, as applicable, in 2010 and subsequent years.

(g)(1) Each SIP revision that contains control measures covering non-EGUs as part or all of a State's obligation in meeting its requirement under paragraph (a) of this section must demonstrate that such control measures are adequate to provide for the timely compliance with the State's Annual Non-EGU SO_2 Reduction Requirement under paragraph (e) of this section and are not adopted or implemented by the State, as of May 12, 2005, and are not adopted or implemented by the federal government, as of the date of submission of the SIP revision by the State to EPA.

(2) The demonstration under paragraph (g)(1) of this section must include the following, with respect to each source category of non-EGUs for which the SIP revision requires control measures:

(i) A detailed historical baseline inventory of SO_2 mass emissions from the source category in a representative year consisting, at the State's election, of 2002, 2003, 2004, or 2005, or an average of 2 or more of those years, absent the control measures specified in the SIP revision.

(A) This inventory must represent estimates of actual emissions based on monitoring data in accordance with part 75 of this chapter, if the source category is subject to part 75 monitoring requirements in accordance with part 75 of this chapter.

(B) In the absence of monitoring data in accordance with part 75 of this chapter, actual emissions must be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to part 75 of this chapter and using source-specific or source-category-specific assumptions that ensure a source's or source category's actual emissions are not overestimated. If a State uses factors to estimate emissions, production or utilization, or effectiveness of controls or rules for a source category, such factors must be chosen to ensure that emissions are not overestimated.

(C) For measures to reduce emissions from motor vehicles, emission estimates must be based on an emissions model that has been approved by EPA for use in SIP development and must be consistent with the planning assumptions regarding vehicle miles traveled and other factors current at the time of the SIP development.

(D) For measures to reduce emissions from nonroad engines or vehicles, emission estimates methodologies must be approved by EPA.

(ii) A detailed baseline inventory of SO_2 mass emissions from the source category in the years 2010 and 2015, absent the control measures specified in the SIP revision and reflecting changes in these emissions from the historical baseline year to the years 2010 and 2015, based on projected changes in the production input or output, population, vehicle miles traveled, economic activity, or other factors as applicable to this source category.

(A) These inventories must account for implementation of any control measures that are adopted or implemented by the State, as of May 12, 2005, or adopted or implemented by the federal government, as of the date of submission of the SIP revision by the State to EPA, and must exclude any control measures specified in the SIP revision to meet the SO_2 emissions reduction requirements of this section.

(B) Economic and population forecasts must be as specific as possible to the applicable industry, State, and county of the source or source category and must be consistent with both national projections and relevant official planning assumptions, including estimates of population and vehicle miles traveled developed through consultation between State and local transportation and air quality agencies. However, if these official planning assumptions are inconsistent with official U.S. Census projections of population or with energy consumption projections contained in the U.S. Department of Energy's most recent Annual Energy Outlook, then the SIP revision must make adjustments to correct the inconsistency or must demonstrate how the official planning assumptions are more accurate.

(C) These inventories must account for any changes in production method, materials, fuels, or efficiency that are expected to occur between the historical baseline year and 2010 or 2015, as appropriate.

(iii) A projection of SO_2 mass emissions in 2010 and 2015 from the source category assuming the same projected changes as under paragraph (g)(2)(ii) of this section and resulting from implementation of each of the control measures specified in the SIP revision.

(A) These inventories must address the possibility that the State's new control measures may cause production or utilization, and emissions, to shift to unregulated or less stringently regulated sources in the source category in the same or another State, and these inventories must include any such amounts of emissions that may shift to such other sources.

(B) The State must provide EPA with a summary of the computations, assumptions, and judgments used to determine the degree of reduction in projected 2010 and 2015 SO_2 emissions that will be achieved from the implementation of the new control measures compared to the relevant baseline emissions inventory.

(iv) The result of subtracting the amounts in paragraph (g)(2)(iii) of this section for 2010 and 2015, respectively, from the lower of the amounts in paragraph (g)(2)(i) or (g)(2)(ii) of this section for 2010 and 2015, respectively, may be credited towards the State's Annual Non-EGU SO_2 Reduction Requirement in paragraph (e)(3) of this section for the appropriate period.

(v) Each SIP revision must identify the sources of the data used in each estimate and each projection of emissions.

(h) Each SIP revision must comply with § 51.116 (regarding data availability).

(i) Each SIP revision must provide for monitoring the status of compliance with any control measures adopted to meet the State's requirements under paragraph (e) of this section, as follows:

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

(i) Information on the amount of SO_2 emissions from the stationary sources; and

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

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

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

(4)(i) If the SIP revision contains measures to control EGUs, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of part 75 of this chapter.

(ii) If the SIP revision contains measures to control fossil fuel-fired non-EGUs that are boilers or combustion turbines with a maximum design heat input greater than 250 mmBtu/hr, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of part 75 of this chapter.

(iii) If the SIP revision contains measures to control any other non-EGUs that are not described in paragraph (i)(4)(ii) of this section, then the SIP revision must require such sources to comply with the monitoring, recordkeeping, and reporting provisions of part 75 of this chapter, or the State must demonstrate why such requirements are not practicable and adopt alternative requirements that ensure that the required emissions reductions will be quantified, to the maximum extent practicable, with the same degree of assurance with which emissions are quantified for sources subject to part 75 of this chapter.

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

(1) Adopt emissions standards and limitations and any other measures necessary for attainment and maintenance of the State's relevant Annual EGU SO_2 Budget or the Annual Non-EGU SO_2 Reduction Requirement, as applicable, under paragraph (e) of this section;

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

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

(4)(i) Require owners or operators of stationary sources to install, maintain, and use emissions monitoring devices and to make periodic reports to the State on the nature and amounts of emissions from such stationary sources; and

(ii) Make the data described in paragraph (j)(4)(i) of this section available to the public within a reasonable time after being reported and as correlated with any applicable emissions standards or limitations.

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

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

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

(2) Each SIP revision must comply with § 51.240 (regarding general plan requirements).

(m) Each SIP revision must comply with § 51.280 (regarding resources).

(n) Each SIP revision must provide for State compliance with the reporting requirements in § 51.125.

(o)(1) Notwithstanding any other provision of this section, if a State adopts regulations substantively identical to subparts AAA through III of part 96 of this chapter (CAIR SO_2 Trading Program), incorporates such subparts by reference into its regulations, or adopts regulations that differ substantively from such subparts only as set forth in paragraph (o)(2) of this section, then such emissions trading program in the State's SIP revision is automatically approved as meeting the requirements of paragraph (e) of this section, provided that the State has the legal authority to take such action and to implement its responsibilities under such regulations.

(2) If a State adopts an emissions trading program that differs substantively from subparts AAA through III of part 96 of this chapter only as follows, then the emissions trading program is approved as set forth in paragraph (o)(1) of this section.

(i) The State may decline to adopt the CAIR SO_2 opt-in provisions of subpart III of this part and the provisions applicable only to CAIR SO_2 opt-in units in subparts AAA through HHH of this part.

(ii) The State may decline to adopt the CAIR SO_2 opt-in provisions of § 96.288(b) of this chapter and the provisions of subpart III of this part applicable only to CAIR SO_2 opt-in units under § 96.288(b).

(iii) The State may decline to adopt the CAIR SO_2 opt-in provisions of § 96.288(c) of this chapter and the provisions of subpart II of this part applicable only to CAIR SO_2 opt-in units under § 96.288(c).

(3) A State that adopts an emissions trading program in accordance with paragraph (o)(1) or (2) of this section is not required to adopt an emissions trading program in accordance with § 96.123 (o)(1) or (2) or (aa)(1) or (2) of this chapter.

(4) If a State adopts an emissions trading program that differs substantively from subparts AAA through III of part 96 of this chapter, other than as set forth in paragraph (o)(2) of this section, then such emissions trading program is not automatically approved as set forth in paragraph (o)(1) or (2) of this section and will be reviewed by the Administrator for approvability in accordance with the other provisions of this section, provided that the SO_2 allowances issued under such emissions trading program shall not, and the SIP revision shall state that such SO_2 allowances shall not, qualify as CAIR SO_2 allowances under any emissions trading program approved under paragraph (o)(1) or (2) of this section.

(p) If a State's SIP revision does not contain an emissions trading program approved under paragraph (o)(1) or (2) of this section but contains control measures on EGUs as part or all of a State's obligation in meeting its requirement under paragraph (a) of this section:

(1) The SIP revision shall provide, for each year that the State has such

obligation, for the permanent retirement of an amount of Acid Rain allowances allocated to sources in the State for that year and not deducted by the Administrator under the Acid Rain Program and any emissions trading program approved under paragraph (o)(1) or (2) of this section, equal to the difference between—

(A) The total amount of Acid Rain allowances allocated under the Acid Rain Program to the sources in the State for that year; and

(B) If the State's SIP revision contains only control measures on EGUs, the State's Annual EGU SO_2 Budget for the appropriate period as specified in paragraph (e)(2) of this section or, if the State's SIP revision contains control measures on EGUs and non-EGUs, the State's Annual EGU SO_2 Budget for the appropriate period as specified in the SIP revision.

(2) The SIP revision providing for permanent retirement of Acid Rain allowances under paragraph (p)(1) of this section must ensure that such allowances are not available for deduction by the Administrator under the Acid Rain Program and any emissions trading program approved under paragraph (o)(1) or (2) of this section.

(q) The terms used in this section shall have the following meanings:

Acid Rain allowance means a limited authorization issued by the Administrator under the Acid Rain Program to emit up to one ton of sulfur dioxide during the specified year or any year thereafter, except as otherwise provided by the Administrator.

Acid Rain Program means a multi-State sulfur dioxide and nitrogen oxides air pollution control and emissions reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

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

Allocate or *allocation* means, with regard to allowances, the determination of the amount of allowances to be initially credited to a source.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

Clean Air Act or *CAA* means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity—

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

Combustion turbine means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated heat recovery steam generator and steam turbine.

Commence operation means to have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber.

Electric generating unit or *EGU* means:

(1) Except as provided in paragraph (2) of this definition, a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(2) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (1) of this definition starting on the day on which the unit first no longer qualifies as a cogeneration unit.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

Generator means a device that produces electricity.

Maximum design heat input means:

(1) Starting from the initial installation of a unit, the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as specified by the manufacturer of the unit;

(2)(i) Except as provided in paragraph (2)(ii) of this definition, starting from the completion of any subsequent physical change in the unit resulting in an increase in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis, such increased maximum amount as specified by the person conducting the physical change; or

(ii) For purposes of applying the definition of the term ''potential electrical output capacity,'' starting from the completion of any subsequent physical change in the unit resulting in a decrease in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis, such decreased maximum amount as specified by the person conducting the physical change.

NAAQS means National Ambient Air Quality Standard.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as specified by the person conducting the physical change.

Non-EGU means a source of SO_2 emissions that is not an EGU.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself.

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

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

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process, excluding any heat contained in condensate return or makeup water;

(2) Used in a heat application (*e.g.*, space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.*, thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

■ 6. Part 51 is amended by adding § 51.125 to Subpart G to read as follows:

§ 51.125 Emissions reporting requirements for SIP revisions relating to budgets for SO_2 and NO_X emissions.

(a) For its transport SIP revision under § 51.123 and/or 51.124, each State must submit to EPA SO_2 and/or NO_X emissions data as described in this section.

(1) Alabama, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maryland, Michigan, Minnesota, Mississippi, Missouri, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin and the District of Columbia, must report annual (12 months) emissions of SO_2 and NO_X.

(2) Alabama, Arkansas, Connecticut, Deleware, Florida, Illinois, Indinia, Iowa, Kentucky, Lousianna, Maryland, Massachusetts, Michigan, Mississippi, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin and the District of Columbia must report ozone season (May 1 through September 30) emissions of NO_X.

(b) Each revision must provide for periodic reporting by the State of SO_2 and/or NO_X emissions data as specified in paragraph (a) of this section to demonstrate whether the State's emissions are consistent with the projections contained in its approved SIP submission.

(1) Every-year reporting cycle. As applicable, each revision must provide for reporting of SO_2 and NO_X emissions data every year as follows:

(i) The States identified in paragraph (a)(1) of this section must report to EPA annual emissions data every year from all SO_2 and NO_X sources within the State for which the State specified control measures in its SIP submission under §§ 51.123 and/or 51.124.

(ii) The States identified in paragraph (a)(2) of this section must report to EPA ozone season and summer daily emissions data every year from all NO_X sources within the State for which the State specified control measures in its SIP submission under § 51.123.

(iii) If sources report SO_2 and NO_X emissions data to EPA in a given year pursuant to a trading program approved under § 51.123(o) or § 51.124(o) of this part or pursuant to the monitoring and reporting requirements of 40 CFR part 75, then the State need not provide annual reporting of these pollutants to EPA for such sources.

(2) *Three-year reporting cycle.* As applicable, each plan must provide for triennial (*i.e.*, every third year) reporting of SO_2 and NO_X emissions data from all sources within the State.

(i) The States identified in paragraph (a)(1) of this section must report to EPA annual emissions data every third year from all SO_2 and NO_X sources within the State.

(ii) The States identified in paragraph (a)(2) of this section must report to EPA ozone season and ozone daily emissions data every third year from all NO_X sources within the State.

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

(c) The data reported in paragraph (b) of this section must meet the requirements of subpart A of this part.

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

(e) *Reporting schedules.* (1) Reports are to begin with data for emissions occurring in the year 2008, which is the first year of the 3-year cycle.

(2) After 2008, 3-year cycle reports are to be submitted every third year and every-year cycle reports are to be submitted each year that a triennial report is not required.

(3) States must submit data for a required year no later than 17 months after the end of the calendar year for which the data are collected.

(f) Data reporting procedures are given in subpart A of this part. When submitting a formal NO_X budget emissions report and associated data, States shall notify the appropriate EPA Regional Office.

(g) *Definitions.* (1) As used in this section, ''ozone season'' is defined as follows:

Ozone season.—The five month period from May 1 through September 30.

(2) Other words and terms shall have the meanings set forth in appendix A of subpart A of this part.

PART 72—PERMITS REGULATION

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

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

§ 72.2 [Amended]

■ 2. Section 72.2 is amended by:

■ a. Amend the definition of ''Acid rain emissions limitation'' by replacing, in paragraph (1)(i), the words ''an affected unit'' with the words ''the affected units at a source'' and replacing, in paragraph (1)(ii)(C), the words ''compliance subaccount for that unit'' with the words ''compliance account for that source'';

■ b. Amend the definition of ''Advance allowance'' by replacing the word ''unit's'' with the word ''source'';

■ c. Amend the definition of ''Allocate or allocation'' by replacing the words ''unit account'' with the words ''compliance account'';

■ d. Amend the definition of ''Allowance deduction, or deduct'' by replacing the words ''compliance subaccount, or future year subaccount,'' with the words ''compliance account'' and replacing the words ''from an affected unit'' with the words ''from the affected units at an affected source'';

■ e. Amend the definition of ''Allowance transfer deadline'' by replacing the words ''affected unit's compliance subaccount'' with the words ''an affected source's compliance account'' and replacing the words ''the unit's'' with the words ''the source's'';

■ f. Amend the definition of ''Authorized account representative'' by replacing the words ''unit account'' with the words ''compliance account'' and replacing the words ''affected unit'' with the words ''affected source and the affected units at the source'';

■ g. Amend the definition of ''Compliance use date'' by replacing the word ''unit's'' with the word ''source's'';

■ h. Amend the definition of ''Excess emissions'' by, in paragraph (1), replacing the words ''an affected unit'' with the words ''the affected units at an affected source'' and replacing the words ''for the unit'' with the words ''for the source'';

■ i. Amend the definition of ''General account'' by replacing the words ''unit account'' with the words ''compliance account'';

■ j. Amend the definition of ''Offset Plan'' by replacing the word ''unit'' with the word ''source'';

■ k. Amend the definition of ''Recordation, record, or recorded'' by removing the words ''or subaccount'';

■ l. Amend the definition of ''Source'' by replacing the words ''under the Act.'' with the words ''under the Act, provided that one or more combustion or process sources that have, under § 74.4(c) of this chapter, a different designated representative than the designated representative for one or more affected utility units at a source shall be treated as being included in a separate source from the source that includes such utility units for purposes of parts 72 through 78 of this chapter, but shall be treated as being included in the same source as the source that includes such utility units for purposes of section 502(c) of the Act.''

■ m. Amend the definition of ''Spot allowance'' by replacing the word ''unit's'' with the word ''source's''; and

■ n. Revise the definition of ''Cogeneration unit'';

■ o. Add a new definition of ''Compliance account''; and

■ p. Remove the definitions of ''Compliance subaccount'', ''Current year subaccount'', ''Direct Sale Subaccount'', ''Future year subaccount'', and ''Unit account''.

§ 72.2 Definitions.

* * * * *

Cogeneration unit means a unit that has equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes, through sequential use of energy.

* * * * *

Compliance account means an Allowance Tracking System account, established by the Administrator under § 73.31(a) or (b) of this chapter or § 74.40(a) of this chapter for an affected source and for each affected unit at the source.

* * * * *

§ 72.7 [Amended]

■ 3. Section 72.7 is amended in paragraph (c)(1)(ii), in the first sentence, by replacing the word ''unit's Allowance Tracking System account'' with the words ''compliance account of the source that includes the unit'', and by removing the third sentence of paragraph (c)(1)(ii).

§ 72.9 [Amended]

■ 4. Section 72.9 is amended by:

■ a. In paragraph (b)(2), replace the word ''unit'' with the words ''source or unit, as appropriate,'';

■ b. In paragraph (c)(1)(i), replace the words ''unit's compliance subaccount'' with the words ''source's compliance account'' and replace the words ''from the unit'' with the words ''from the affected units at the source'';

■ c. In paragraphs (e)(1) and (e)(2) introductory text, replace the words ''an affected unit'' with the words ''an affected source'';

■ d. In paragraph (g)(6), remove the second sentence; and

■ e. In paragraph (h)(2), replace the word ''unit'' with the word ''source'' wherever it appears.

§ 72.21 [Amended]

■ 5. Section 72.21 is amended by:

■ a. In paragraph (b)(1), remove the word ''affected'' wherever it appears; and

■ b. In paragraph (e)(2), replace the words ''unit account'' with the words ''compliance account''.

§ 72.24 [Amended]

■ 6. Section 72.24 is amended by removing and reserving paragraphs (a)(5), (a)(7), and (a)(10).

§ 72.40 [Amended]

■ 7–8. Section 72.40 is amended, in paragraph (a)(1), replace the words ''unit's compliance subaccount'' with the words ''compliance account of the source where the unit is located''; remove the words '', or in the compliance subaccount of another affected unit at the source to the extent provided in § 73.35(b)(3),''; and replace the words ''from the unit'' with the words ''from the affected units at the source''.

§ 72.72 [Amended]

■ 9. Section 72.72 is amended by:

■ a. In paragraph (a)(1), add the words ''or affected source'' after the words ''affected unit'';

■ b. In paragraph (a)(2), add the words ''or an affected source's'' after the words ''affected unit's''; and

■ c. In paragraph (a)(3), add the words ''or affected source'' after the words ''affected unit'' whenever they appear.

§ 72.73 [Amended]

■ 10. Section 72.73 is amended in paragraph (b)(2) by replacing the words ''the first Acid Rain permit'' with the words ''an Acid Rain permit''.

§ 72.90 [Amended]

■ 11. Section 72.90 is amended by, in paragraph (a), add, after the words ''each calendar year'', the words ''during 1995 through 2005''.

§ 72.95 [Amended]

■ 12. Section 72.95 is amended by:

■ a. In the introductory text, replace the words ''an affected unit's compliance subaccount'' with the words ''an affected source's compliance account''; and

■ b. In paragraph (a), replace the words ''by the unit'' with the words ''by the affected units at the source''.

§ 72.96 [Amended]

■ 13. Section 72.96 is amended in paragraph (b), by replacing the words ''unit''s Allowance Tracking System account'' with the words ''source's compliance account''.

PART 73—SULFUR DIOXIDE ALLOWANCE SYSTEM

■ 1. The authority citation for part 73 continues to read as follows:

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

§ 73.10 [Amended]

■ 2. Section 73.10 is amended by:
■ a. In paragraph (a), replace the words ''unit account for each'' with the words ''compliance account for each source that includes a'' and remove the words ''in each future year subaccount''; and
■ b. In paragraphs (b)(1) and (b)(2), replace the words ''unit account for each'' with the words ''compliance account for each source that includes a'' and replace the words ''in the future year subaccounts representing calendar years'' with the words ''for the years''.

§ 73.27 [Amended]

■ 3. Section 73.27 is amended in paragraphs (c)(3) and (c)(5) by replacing the words ''unit's Allowance Tracking System account'' with the words ''compliance account of the source that includes the unit''.

§ 73.30 [Amended]

■ 4. Section 73.30 is amended by:
■ a. In paragraph (a), add the word ''compliance'' after the word ''establish''; replace the words ''affected units'' with the words ''affected sources''; and replace the words ''unit's Allowance Tracking System account'' with the words ''source's compliance account''; and
■ b. In paragraph (b), replace the word ''unit'' with the word ''source'' and replace the words ''Allowance Tracking System account'' with the words ''general account''.

§ 73.31 [Amended]

■ 5. Section 73.31 is amended by:
■ a. In paragraph (a), replace the words ''an Allowance Tracking System account'' with the words ''a compliance account'' and replace the words ''each unit'' with the words ''each source that includes a unit'';
■ b. In paragraph (b), replace the words ''an Allowance Tracking System account for the unit.'' with the words ''a compliance account for the source that includes the unit, unless the source already has a compliance account.''; and
■ c. In paragraph (c)(1)(v), replace the words ''Allowance Tracking System account'' with the words ''general account'' and remove the words ''I shall abide by any fiduciary responsibilities assigned pursuant to the binding agreement.''.

§ 73.32 [Removed and Reserved]

■ 6. Section 73.32 is removed and reserved.

§ 73.33 [Amended]

■ 7. Section 73.33 is amended by removing and reserving paragraphs (b) and (c).

§ 73.34 [Amended]

■ 8. Section 73.34 is amended by:
■ a. Revise paragraphs (a) and (b) to read as set forth below;
■ b. In paragraph (c) introductory text, remove the paragraph heading and replace the words ''compliance, current year, and future year'' with the words ''compliance account and general account''.

§ 73.34 Recordation in accounts.

(a) After a compliance account is established under § 73.31(a) or (b), the Administrator will record in the compliance account any allowance allocated to any affected unit at the source for 30 years starting with the later of 1995 or the year in which the compliance account is established and any allowance allocated for 30 years starting with the later of 1995 or the year in which the compliance account is established and transferred to the source with the transfer submitted in accordance with § 73.50. In 1996 and each year thereafter, after Administrator has completed the deductions pursuant to § 73.35(b), the Administrator will record in the compliance account any allowance allocated to any affected unit at the source for the new 30th year (*i.e.*, the year that is 30 years after the calendar year for which such deductions are made) and any allowance allocated for the new 30th year and transferred to the source with the transfer submitted in accordance with § 73.50.

(b) After a general account is established under § 73.31(c), the Administrator will record in the general account any allowance allocated for 30 years starting with the later of 1995 or the year in which the general account is established and transferred to the general account with the transfer submitted in accordance with § 73.50. In 1996 and each year thereafter, after the Administrator has completed the deductions pursuant to § 73.35(b), the Administrator will record in the general account any allowance allocated for the new 30th year (*i.e.*, the year that is 30 years after the calendar year for which such deductions are made) and transferred to the general account with the transfer submitted in accordance with § 73.50.

* * * * *

§ 73.35 [Amended]

■ 9. Section 73.35 is amended by:
■ a. In paragraph (a) introductory text and paragraph (a)(1), replace the words ''unit's'' with the word ''source's'';
■ b. In paragraph (a)(2), replace the word ''Such'' with the word ''The'';
■ c. In paragraph (a)(2)(i), replace the words ''the unit's compliance subaccount'' with the words ''the source's compliance account'';
■ d. In paragraph (a)(2)(ii), replace the words ''the unit's compliance subaccount'' with the words ''the source's compliance account'', replace the words ''compliance subaccount for the unit'' with the words ''source's compliance account'', and replace the word ''or'' with the word ''and'';
■ e. Remove paragraph (a)(2)(iii);
■ f. Add a new paragraph (a)(3);
■ g. In paragraph (b)(1), replace the words ''compliance subaccount'' with the words ''compliance account'', add the words ''available for deduction under paragraph (a) of this section'' after the words ''deduct allowances'', and replace the words ''each affected unit's compliance subaccount'' with the words ''each affected source's compliance account'';
■ h. In paragraph (b)(2), replace the words ''allowances remain in the compliance subaccount'' with the words ''allowances available for deduction under paragraph (a) of this section remain in the compliance account'';
■ i. Remove paragraph (b)(3);
■ j. Revise paragraph (c)(1) to read as set forth below;
■ k. In paragraph (c)(2), replace the words ''for the unit'' with the words ''for the units at the source'', replace the words ''in its compliance subaccount.'' with the words ''in the source's compliance account.'', replace the words ''from the compliance subaccount'' with the words ''from the compliance account'', and replace the words ''unit's compliance subaccount'' with the words ''source's compliance account'';
■ l. In paragraph (d), replace the words ''for each unit'' with the words ''for each source'' and replace the word ''unit's'' with the word ''source's''; and
■ m. Remove paragraph (e).

§ 73.35 Compliance.

(a) * * *

(3) The allowance was not previously deducted by the Administrator in accordance with a State SO_2 mass emissions reduction program under § 51.124(o) of this chapter or otherwise permanently retired in accordance with § 51.124(p) of this chapter.

* * * * *

(c)(1) *Identification of allowances by serial number.* The authorized account representative for a source's compliance account may request that specific allowances, identified by serial number, in the compliance account be deducted for a calendar year in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the

Administrator by the allowance transfer deadline for the year and include, in a format prescribed by the Administrator, the identification of the source and the appropriate serial numbers.

* * * * *

§ 73.36 [Amended]

■ 10. Section 73.36 is amended by:
■ a. In paragraph (a), replace the words ''Unit accounts.'' with the words ''Compliance accounts.'' and replace with words ''compliance subaccount'' with the words ''compliance account'' whenever they appear; and
■ b. In paragraph (b), replace the words ''current year subaccount'' with the words ''general account'' whenever they appear and replace the words ''at the end of the current calendar year'' with the words ''not transferred pursuant to subpart D to another Allowance Tracking System account''.
■ 11. Section 73.37 is revised to read as follows:

§ 73.37 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the authorized account representative for the account.

§ 73.38 [Amended]

■ 12. Section 73.38 is amended by:
■ a. In paragraph (a), replace the words ''delete the general account from the Allowance Tracking System.'' with the words ''close the general account.''; and
■ b. In paragraph (b), replace the words ''for a period of a year or more'' with the words ''for a 12-month period or longer''; remove the words ''in its subaccounts''; replace the words ''will notify'' with the words ''may notify''; remove the words ''and eliminated from the Allowance Tracking System''; and remove the last sentence.

§ 73.50 [Amended]

■ 13. Section 73.50 is amended by:
■ a. In paragraph (a), remove the words '', including, but not limited to, transfers of an allowance to and from contemporaneous future year subaccounts, and transfers of an allowance to and from compliance subaccounts and current year subaccounts, and transfers of all allowances allocated for a unit for each calendar year in perpetuity'';
■ b. In paragraph (b)(1)(ii), remove the words '', or correct indication on the allowance transfer where a request involves the transfer of the unit's allowance in perpetuity'';
■ c. In paragraph (b)(2)(ii), remove the words ''Allowance Tracking System'' and ''under 40 CFR part 73, or any other remedies'' and remove the comma after the words ''under State or Federal law''; and
■ d. Remove paragraph (b)(3).

§ 73.51 [Removed and Reserved]

■ 14. Section 73.51 is removed and reserved.

§ 73.52 [Amended]

■ 15. Section 73.52 is amended by:
■ a. In paragraph (a) introductory text, remove the words ''§ 73.50, § 73.51, and'' and add the words ''(or longer as necessary to perform a transfer in perpetuity of allowances allocated to a unit)'' after the words ''five business days'';
■ b. Revise paragraphs (a)(1), (a)(2) and (a)(3);
■ c. Remove paragraph (a)(4);
■ d. Revise paragraph (b); and
■ e. Add a new paragraph (c) to read as follows:

§ 73.52 EPA recordation.

(a) * * *

(1) The transfer is correctly submitted under § 73.50;

(2) The transferor account includes each allowance identified by serial number in the transfer; and

(3) If the allowances identified by serial number specified pursuant to § 73.50(b)(1)(ii) are subject to the limitation on transfer imposed pursuant to § 72.44(h)(1)(i) of this chapter, § 74.42 of this chapter, or § 74.47(c) of this chapter, the transfer is in accordance with such limitation.

(b) To the extent an allowance transfer submitted for recordation after the allowance transfer deadline includes allowances allocated for any year before the year in which the allowance transfer deadline occurs, the transfer of such allowance will not be recorded until after completion of the deductions pursuant to § 73.35(b) for year before the year in which the allowance transfer deadline occurs.

(c) Where an allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§ 73.70 [Amended]

■ 16. Section 73.70 is amended by:
■ a. In paragraph (e), remove the last two sentences.
■ b. In paragraph (f), replace the words ''the subaccount'' by the words ''the Allowance Tracking System account''; and
■ c. In paragraph (i)(1), add the words ''source that includes a'' after the words ''Allowance Tracking System account of each''.

PART 74—SULFUR DIOXIDE OPT-INS

■ 1. The authority citation for part 74 continues to read as follows:

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

§ 74.4 [Amended]

■ 2. Section 74.4 is amended by:
■ a. In paragraph (c)(1), replace the words ''a combustion or process source that is located'' with the words ''one or more combustion or process sources that are located'', replace the words ''such combustion or process source and thereafter, does'' with the words ''such combustion or process sources and thereafter, do'', and replace the words ''designate, for such combustion or process source'' with the words ''designate, for such combustion or process sources''; and
■ b. In paragraph (c)(2), replace the words ''the combustion or process source'' with the words ''the combustion or process sources'' whenever they occur and replace the word ''meets'' with the word ''meet'' in the first sentence.

§ 74.18 [Amended]

■ 3. Section 74.18 is amended in paragraph (d) by removing the last sentence.

§ 74.40 [Amended]

■ 4. Section 74.40 is amended by:
■ a. In paragraph (a), replace the words ''an opt-in account'' with the words ''a compliance account'', replace the words ''an account'' with the words ''a compliance account (unless the source that includes the opt-in source already has a compliance account or the opt-in source has, under § 74.4(c), a different designated representative than the designated representative for the source)'', and remove the last sentence.
■ b. In paragraph (b), replace the words ''allowance account in the Allowance Tracking System'' with the words ''compliance account (unless the source that includes the opt-in source already has a compliance account or the opt-in source has, under § 74.4(c), a different designated representative than the designated representative for the source)''.
■ 5. Section 74.42 is revised to read as follows:

§ 74.42 Limitation on transfers.

(a) With regard to a transfer request submitted for recordation during the period starting January 1 and ending with the allowance transfer deadline in the same year, the Administrator will not record a transfer of an opt-in allowance that is allocated to an opt-in source for the year in which the transfer request is submitted or a subsequent year.

(b) With regard to a transfer request during the period starting with the day after an allowance transfer deadline and ending December 31 in the same year, the Administrator will not record a transfer of an opt-in allowance that is allocated to an opt-in source for a year after the year in which the transfer request is submitted.

§ 74.43 [Amended]

■ 6. Section 74.43 is amended by:
■ a. In paragraph (a), remove the words ''in lieu of any annual compliance certification report required under subpart I of part 72 of this chapter'';
■ b. In paragraph (b)(7), replace the word ''At'' with the words, ''In an annual compliance certification report for a year during 1995 through 2005, at''; and
■ c. In paragraph (b)(8), replace the word ''The'' with the words, ''In an annual compliance certification report for a year during 1995 through 2005, the''.

§ 74.44 [Amended]

■ 7. Section 74.44 is amended by:
■ a. In paragraph (c)(1)(ii), remove the words ''opt-in source's'' and add the words ''of the source that includes the opt-in source'' after the word ''System'';
■ b. In paragraphs (c)(2)(iii)(C), (c)(2)(iii)(D), (c)(2)(iii)(E) introductory text, and (c)(2)(iii)(E)(3), replace the words ''opt-in source's compliance subaccount'' with the words ''compliance account of the source that includes the opt-in source'' whenever they occur; and
■ c. In paragraph (c)(2)(iii)(F), replace the words ''opt-in source's compliance subaccount'' with the words ''compliance account of the source that includes the opt-in source'' and replace the words ''source's compliance subaccount'' with the words ''compliance account of the source that includes the opt-in source''.

§ 74.46 [Amended]

■ 8. Section 74.46 is amended by removing and reserving paragraph (b)(2).

§ 74.47 [Amended]

■ 9. Section 74.47 is amended by:
■ a. In paragraph (a)(3)(iv), remove the words ''opt-in source's'' and add the words ''of the source that includes the opt-in source'' after the word ''System'';
■ b. In paragraph (a)(3)(v), replace the word ''Each'' with the word ''The'', remove the words ''replacement unit's'' and ''(ATS)'', and add the words ''of each source that includes a replacement unit'' after the word ''System'';
■ c. In paragraph (a)(6), replace the words ''Allowance Tracking System account of each replacement unit'' with the words ''compliance account of each source that includes a replacement unit'';
■ d. In paragraph (c), replace the words ''unit account'' with the words ''compliance account of the source that includes the replacement unit'' and replace the words ''account in the Allowance Tracking System'' with the words ''Allowance Tracking System account'';
■ e. In paragraph (d)(1)(ii)(C), remove the words ''opt-in source's'' and ''(ATS)'' and add the words ''of the source that includes the opt-in source'' after the word ''System'';
■ f. In paragraph (d)(1)(ii)(D), replace the words ''(ATS) for each'' with the words ''of each source that includes a'';
■ g. In paragraph (d)(2)(i), replace the words ''Allowance Tracking System accounts for the opt-in source and for each replacement unit'' with the words ''compliance account for each source that includes the opt-in source or a replacement unit'';
■ h. In paragraph (d)(2)(i)(B), replace the words ''Allowance Tracking System account of the opt-in source'' with the words ''compliance account of the source that includes the opt-in source''; and
■ i. In paragraph (d)(2)(ii), replace the words ''Allowance Tracking System accounts for the opt-in source and for each replacement unit'' with the words ''compliance account for each source that includes the opt-in source or a replacement unit''.

§ 74.49 [Amended]

■ 10. Section 74.49 is amended, in paragraph (a) introductory text, by replacing the words ''an opt-in source's compliance subaccount'' with the words ''the compliance account of a source that includes an opt-in source''.

§ 74.50 [Amended]

■ 11. Section 74.50 is amended by:
■ a. In paragraph (a)(2) introductory text, add the words ''source that includes'' after the words ''the account of the'';
■ b. In paragraph (a)(2)(i), replace the words ''opt-in source's compliance subaccount'' with the words ''the compliance account of the source that includes the opt-in source''; and
■ c. In paragraph (b), replace the words ''the opt-in source's unit account'' with the words ''the compliance account of the source that includes the opt-in source''; and
■ d. In paragraph (d), replace the words ''an opt-in source does not hold'' with the words ''the source that includes the opt-in source does not hold''.

PART 77—EXCESS EMISSIONS

■ 1. The authority citation for part 77 continues to read as follows:

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

§ 77.3 [Amended]

■ 2. Section 77.3 is amended by:
■ a. In paragraph (a), replace the words ''affected unit'' with the words ''affected source'' and replace the word ''unit's Allowance Tracking System account'' with the words ''source's compliance account'';
■ b. In paragraphs (b) and (c), replace the word ''unit'' with the word ''source'' wherever it appears; and
■ c. In paragraph (d) introductory text and paragraphs (d)(1) and (d)(2), replace the word ''unit'' with the word ''source'' whenever it appears;
■ d. In paragraphs (d)(3) and (d)(4), replace the words ''unit's Allowance Tracking System account'' with the words ''source's compliance account's'' whenever they appear; and
■ e. In paragraph (d)(5), replace the words ''unit's compliance subaccount'' with the words ''source's compliance account''.

§ 77.4 [Amended]

■ 3. Section 77.4 is amended by:
■ a. In paragraph (b)(1), replace the words ''unit's compliance subaccount'' with the words ''source's compliance account''; and
■ b. In paragraphs (c)(1)(ii)(A), (d)(1), (d)(2), (d)(3), (e)(iv), (g)(2)(ii), (g)(3)(ii), and (g)(3)(iii), replace the word ''unit'' with the word ''source''; and
■ c. In paragraph (k)(2), replace the words ''unit's compliance subaccount'' with the words ''source's compliance account'' and replace the word ''unit'' with the word ''source''.

§ 77.5 [Amended]

■ 4. Section 77.5 is amended by:
■ a. In paragraph (b), replace the words ''compliance subaccount'' with the words ''compliance account'';
■ b. In paragraph (c), replace the words '', from the unit's compliance subaccount'' with the words ''allocated for the year after the year in which the source has excess emissions, from the source's compliance account'', and replace the word ''unit's'' with the word ''source's''; and
■ c. Remove paragraph (d).

§ 77.6 [Amended]

■ 5. Section 77.6 is amended by:
■ a. In paragraph (a)(1), add the words ''occur at the affected source'' after the

words ''sulfur dioxide'' and replace the words ''owners and operators of the affected unit'' with the words ''owners and operators respectively of the affected source and the affected units at the source or of the affected unit'';

■ b. In paragraph (b)(1)(i)(A), replace the word ''unit'' with the words ''source or unit as appropriate''; and

■ c. In paragraphs (b)(3),(c), and (f), replace the word ''unit'' with the words ''source or unit as appropriate''.

PART 78—APPEAL PROCEDURES

■ 1. The title of part 78 is revised to read as set forth above.

■ 2. The authority citation for part 78 continues to read as follows:

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

§ 78.1 [Amended]

■ 3. Section 78.1 is amended by:

■ a. In paragraph (a)(1), replace the words ''parts 72, 73, 74, 75, 76, or 77 of this chapter or part 97 of this chapter'' with the words ''part 72, 73, 74, 75, 76, or 77 of this chapter, subparts AA through II of part 96 of this chapter, subparts AAA through III of part 96 of this chapter, and subparts AAAA through subparts IIII of part 96 of this chapter, or part 97 of this chapter'';

■ b. Revise paragraph (b)(2)(i);

■ c. Add new paragraphs (b)(7), (b)(8), and (b)(9) to read as follows:

§ 78.1 Purpose and scope.

* * * * *

(b) * * *

(2) * * *

(i) The correction of an error in an Allowance Tracking System account;

* * * * *

(7) Under subparts AA through II of part 96 of this chapter,

(i) The decision on the allocation of CAIR NO_X allowances under § 96.141(b)(2) or (c)(2) of this chapter.

(ii) The decision on the deduction of CAIR NO_X allowances, and the adjustment of the information in a submission and the decision on the deduction or transfer of CAIR NO_X allowances based on the information as adjusted, under § 96.154 of this chapter;

(iii) The correction of an error in a CAIR NO_X Allowance Tracking System account under § 96.156 of this chapter;

(iv) The decision on the transfer of CAIR NO_X allowances under § 96.161 of this chapter;

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

(vi) The approval or disapproval of a petition under § 96.175 of this chapter.

(8) Under subparts AAA through III of part 96 of this chapter,

(i) The decision on the deduction of CAIR SO_2 allowances, and the adjustment of the information in a submission and the decision on the deduction or transfer of CAIR SO_2 allowances based on the information as adjusted, under § 96.254 of this chapter;

(ii) The correction of an error in a CAIR SO_2 Allowance Tracking System account under § 97.256 of this chapter;

(iii) The decision on the transfer of CAIR SO_2 allowances under § 96.261 of this chapter;

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

(v) The approval or disapproval of a petition under § 96.275 of this chapter.

(9) Under subparts AAAA through IIII of part 96 of this chapter,

(i) The decision on the allocation of CAIR NO_X Ozone Season allowances under § 96.341(b)(2) or (c)(2)of this chapter.

(ii) The decision on the deduction of CAIR NO_X Ozone Season allowances, and the adjustment of the information in a submission and the decision on the deduction or transfer of CAIR NO_X Ozone Season allowances based on the information as adjusted, under § 96.354 of this chapter;

(iii) The correction of an error in a CAIR NO_X Ozone Season Allowance Tracking System account under § 96.356 of this chapter;

(iv) The decision on the transfer of CAIR NO_X Ozone Season allowances under § 96.361;

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

(vi) The approval or disapproval of a petition under § 96.375 of this chapter.

* * * * *

§ 78.3 [Amended]

■ 4. Section 78.3 is amended by:

■ a. In paragraph (b)(3)(i), add the words ''or the CAIR designated representative or CAIR authorized account representative under paragraph (a)(4), (5), or (6) of this section (unless the CAIR designated representative or CAIR authorized account representative is the petitioner)'' after the words ''(unless the NO_X authorized account representative is the petitioner)'';

■ b. In paragraph (c)(7), replace the words ''or part 97 of this chapter, as appropriate'' with the words '', subparts AA through II of part 96 of this chapter, subparts AAA through III of part 96 of this chapter, subparts AAAA through IIII of part 96 of this chapter, or part 97 of this chapter, as appropriate'';

■ c. In paragraph (d)(3), add the words ''or on an account certificate of representation submitted by a CAIR designated representative or an application for a general account submitted by a CAIR authorized account representative under subparts AA through II, subparts AAA through III, or subparts AAAA through IIII of part 96 of this chapter'' after the words ''under the NO_X Budget Trading Program'';

■ d. Add new paragraphs (a)(4), (a)(5), (a)(6), (d)(5), (d)(6), and (d)(7) to read as follows:

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

(a) * * *

(4) The following persons may petition for administrative review of a decision of the Administrator that is made under subparts AA through II of part 96 of this chapter and that is appealable under § 78.1(a):

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

(ii) Any interested person.

(5) The following persons may petition for administrative review of a decision of the Administrator that is made under subparts AAA through III of part 96 of this chapter and that is appealable under § 78.1(a):

(i) The CAIR designated representative for a unit or source, or the CAIR authorized account representative for any CAIR SO_2 Allowance Tracking System account, covered by the decision; or

(ii) Any interested person.

(6) The following persons may petition for administrative review of a decision of the Administrator that is made under subparts AAAA through IIII of part 96 of this chapter and that is appealable under § 78.1(a):

(i) The CAIR designated representative for a unit or source, or the CAIR authorized account representative for any CAIR Ozone Season NO_X Allowance Tracking System account, covered by the decision; or

(ii) Any interested person.

* * * * *

(d) * * *

(5) Any provision or requirement of subparts AA through II of part 96 of this chapter, including the standard requirements under § 96.106 of this chapter and any emission monitoring or reporting requirements.

(6) Any provision or requirement of subparts AAA through III of part 96 of this chapter, including the standard requirements under § 96.206 of this

chapter and any emission monitoring or reporting requirements.

(7) Any provision or requirement of subparts AAAA through IIII of part 96 of this chapter, including the standard requirements under § 96.306 of this chapter and any emission monitoring or reporting requirements.

§ 78.4 [Amended]

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

§ 78.4 Filings.

(a) * * * Any filings on behalf of owners and operators of a CAIR NO_X, SO_2, or NO_X Ozone Season unit or source shall be signed by the CAIR designated representative. Any filings on behalf of persons with an interest in CAIR NO_X allowances, CAIR SO_2 allowances, or CAIR NO_X Ozone Season allowances in a general account shall be signed by the CAIR authorized account representative. * * *

* * * * *

§ 78.5 [Amended]

■ 6. Section 78.5 is amended, in paragraph (a), by removing the words '', or a claim or error notification was submitted,'' the words ''or in the claim of error notification'', and the words ''or the period for submitting a claim of error notification''.

§ 78.12 [Amended]

■ 7. Section 78.12 is amended by:
■ a. In paragraph (a) introductory text, remove the words '', or to submit a claim of error notification''; and
■ b. In paragraph (a)(2), replace the words ''NO_X Budget permit'' with the words '', NO_X Budget permit, CAIR permit,''.

§ 78.13 [Amended]

■ 8. Section 78.13 is amended by, in paragraph (b), removing the word ''also''.

PART 96—[AMENDED]

■ 1. Authority citation for Part 96 is revised to read as follows:

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

■ 2. Part 96 is amended by adding subparts AA through II, to read as follows:

Subpart AA—CAIR NO_X Annual Trading Program General Provisions

Sec.

Subpart BB—CAIR Designated Representative for CAIR NO_X Sources

Subpart CC—Permits

Subpart DD—[Reserved]

Subpart EE—CAIR NO_X Allowance Allocations

Subpart FF—CAIR NO_X Allowance Tracking System

Subpart GG—CAIR NO_X Allowance Transfers

Subpart HH—Monitoring and Reporting

Subpart II—CAIR NO_X Opt-in Units

Subpart AA—CAIR NO_X Annual Trading Program General Provisions

§ 96.101 Purpose.

This subpart and subparts BB through II establish the model rule comprising general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the State Clean Air Interstate Rule (CAIR) NO_X Annual Trading Program, under section 110 of the Clean Air Act and § 51.123 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides. The owner or operator of a unit or a source shall comply with the requirements of this subpart and subparts BB through II as a matter of federal law only if the State with jurisdiction over the unit and the source incorporates by reference such subparts or otherwise adopts the requirements of such subparts in accordance with § 51.123(o)(1) or (2) of this chapter, the State submits to the Administrator one or more revisions of the State implementation plan that include such adoption, and the Administrator approves such revisions. If the State adopts the requirements of such subparts in accordance with § 51.123(o)(1) or (2) of this chapter, then the State authorizes the Administrator to assist the State in implementing the CAIR NO_X Annual Trading Program by carrying out the functions set forth for the Administrator in such subparts.

§ 96.102 Definitions.

The terms used in this subpart and subparts BB through II shall have the meanings set forth in this section as follows:

Account number means the identification number given by the Administrator to each CAIR NO_X Allowance Tracking System account.

Acid Rain emissions limitation means a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program.

Acid Rain Program means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

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

Allocate or allocation means, with regard to CAIR NO_X allowances issued under subpart EE, the determination by the permitting authority or the Administrator of the amount of such CAIR NO_X allowances to be initially credited to a CAIR NO_X unit or a new unit set-aside and, with regard to CAIR NO_X allowances issued under § 96.188, the determination by the permitting authority of the amount of such CAIR NO_X allowances to be initially credited to a CAIR NO_X unit.

Allowance transfer deadline means, for a control period, midnight of March 1, if it is a business day, or, if March 1 is not a business day, midnight of the first business day thereafter immediately following the control period and is the deadline by which a CAIR NO_X allowance transfer must be submitted for recordation in a CAIR NO_X source's compliance account in order to be used to meet the source's CAIR NO_X emissions limitation for such control period in accordance with § 96.154.

Alternate CAIR designated representative means, for a CAIR NO_X source and each CAIR NO_X unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source in accordance with subparts BB and II of this part, to act on behalf of the CAIR designated representative in matters pertaining to the CAIR NO_X Annual Trading Program. If the CAIR NO_X source is also a CAIR SO_2 source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR SO_2 Trading Program. If the CAIR NO_X source is also a CAIR NO_X Ozone Season source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR NO_X Ozone Season Trading Program. If the CAIR NO_X source is also subject to the Acid Rain Program, then this natural person shall be the same person as the alternate designated representative under the Acid Rain Program.

Automated data acquisition and handling system or *DAHS* means that component of the continuous emission monitoring system, or other emissions monitoring system approved for use under subpart HH of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart HH of this part.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

CAIR authorized account representative means, with regard to a general account, a responsible natural person who is authorized, in accordance with subparts BB and II of this part, to transfer and otherwise dispose of CAIR NO_X allowances held in the general account and, with regard to a compliance account, the CAIR designated representative of the source.

CAIR designated representative means, for a CAIR NO_X source and each CAIR NO_X unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BB and II of this part, to represent and legally bind each owner and operator in matters pertaining to the CAIR NO_X Annual Trading Program. If the CAIR NO_X source is also a CAIR SO_2 source, then this natural person shall be the same person as the CAIR designated representative under the CAIR SO_2 Trading Program. If the CAIR NO_X source is also a CAIR NO_X Ozone Season source, then this natural person shall be the same person as the CAIR designated representative under the CAIR NO_X Ozone Season Trading Program. If the CAIR NO_X source is also subject to the Acid Rain Program, then this natural person shall be the same person as the designated representative under the Acid Rain Program.

CAIR NO_X allowance means a limited authorization issued by the permitting authority under subpart EE of this part or § 96.188 to emit one ton of nitrogen oxides during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CAIR NO_X Program. An authorization to emit nitrogen oxides that is not issued under provisions of a State implementation plan that are approved under § 51.123(o)(1) or (2) of this chapter shall not be a CAIR NO_X allowance.

CAIR NO_X allowance deduction or *deduct CAIR NO_X allowances* means the permanent withdrawal of CAIR NO_X allowances by the Administrator from a compliance account in order to account for a specified number of tons of total nitrogen oxides emissions from all CAIR NO_X units at a CAIR NO_X source for a control period, determined in accordance with subpart HH of this part, or to account for excess emissions.

CAIR NO_X Allowance Tracking System means the system by which the Administrator records allocations, deductions, and transfers of CAIR NO_X allowances under the CAIR NO_X Annual Trading Program. Such allowances will be allocated, held, deducted, or transferred only as whole allowances.

CAIR NO_X Allowance Tracking System account means an account in the CAIR NO_X Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of CAIR NO_X allowances.

CAIR NO_X allowances held or *hold CAIR NO_X allowances* means the CAIR NO_X allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts FF, GG, and II of this part, in a CAIR NO_X Allowance Tracking System account.

CAIR NO_X Annual Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AA through II of this part and § 51.123 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

CAIR NO_X emissions limitation means, for a CAIR NO_X source, the tonnage equivalent of the CAIR NO_X allowances available for deduction for the source under § 96.154(a) and (b) for a control period.

CAIR NO_X Ozone Season source means a source that includes one or more CAIR NO_X Ozone Season units.

CAIR NO_X Ozone Season Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAAA through IIII of this part and § 51.123 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

CAIR NO_X Ozone Season unit means a unit that is subject to the CAIR NO_X Ozone Season Trading Program under § 96.304 and a CAIR NO_X Ozone Season opt-in unit under subpart IIII of this part.

CAIR NO_X source means a source that includes one or more CAIR NO_X units.

CAIR NO_X unit means a unit that is subject to the CAIR NO_X Annual Trading Program under § 96.104 and, except for purposes of § 96.105 and subpart EE of this part, a CAIR NO_X opt-in unit under subpart II of this part.

CAIR permit means the legally binding and federally enforceable written document, or portion of such document, issued by the permitting authority under subpart CC of this part, including any permit revisions, specifying the CAIR NO_X Annual Trading Program requirements applicable to a CAIR NO_X source, to each CAIR NO_X unit at the source, and to the owners and operators and the CAIR designated representative of the source and each such unit.

CAIR SO_2 source means a source that includes one or more CAIR SO_2 units.

CAIR SO_2 Trading Program means a multi-state sulfur dioxide air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAA through III of this part and § 51.124 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

CAIR SO_2 unit means a unit that is subject to the CAIR SO_2 Trading Program under § 96.204 and a CAIR SO_2 opt-in unit under subpart III of this part.

Clean Air Act or *CAA* means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means:

(1) Except for purposes of subpart EE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during any year; or

(2) For purposes of subpart EE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during a specified year.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity—

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

Combustion turbine means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated heat recovery steam generator and steam turbine.

Commence commercial operation means, with regard to a unit serving a generator:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 96.105.

(i) For a unit that is a CAIR NO_X unit under § 96.104 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit that is a CAIR NO_X unit under § 96.104 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 96.105, for a unit that is not a CAIR NO_X unit under § 96.104 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and is not a unit under paragraph (3) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a CAIR NO_X unit under § 96.104.

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(3) Notwithstanding paragraph (1) of this definition and except as provided in § 96.184(h) or § 96.187(b)(3), for a CAIR NO_X opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, the unit's date for commencement of commercial operation shall be the date on which the owner or operator is required to start monitoring and reporting the NO_X emissions rate and the heat input of the unit under § 96.184(b)(1)(i).

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (3) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (3) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(4) Notwithstanding paragraphs (1) through (3) of this definition, for a unit not serving a generator producing electricity for sale, the unit's date of commencement of operation shall also be the unit's date of commencement of commercial operation.

Commence operation means:

(1) To have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber, except as provided in § 96.105.

(i) For a unit that is a CAIR NO_X unit under § 96.104 on the date the unit commences operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit that is a CAIR NO_X unit under § 96.104 on the date the unit commences operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 96.105, for a unit that is not a CAIR NO_X unit under § 96.104 on the date the unit commences operation as defined in paragraph (1) of this definition and is not a unit under paragraph (3) of this definition, the unit's date for commencement of operation shall be the date on which the unit becomes a CAIR NO_X unit under § 96.104.

(i) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(3) Notwithstanding paragraph (1) of this definition and except as provided in § 96.184(h) or § 96.187(b)(3), for a CAIR NO_X opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, the unit's date for commencement of operation shall be the date on which the owner or operator is required to start monitoring and reporting the NO_X emissions rate and the heat input of the unit under § 96.184(b)(1)(i).

(i) For a unit with a date for commencement of operation as defined in paragraph (3) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit with a date for commencement of operation as defined in paragraph (3) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means a CAIR NO_X Allowance Tracking System account, established by the Administrator for a CAIR NO_X source under subpart FF or II of this part, in which any CAIR NO_X allowance allocations for the CAIR NO_X units at the source are initially recorded and in which are held any CAIR NO_X allowances available for use for a control period in order to meet the source's CAIR NO_X emissions limitation in accordance with § 96.154.

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

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A nitrogen oxides concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X emissions, in parts per million (ppm);

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

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

(5) A carbon dioxide monitoring system, consisting of a CO_2 pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(6) An oxygen monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2, in percent O_2.

Control period means the period beginning January 1 of a calendar year and ending on December 31 of the same year, inclusive.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the CAIR designated representative and as determined by the Administrator in accordance with subpart HH of this part.

Excess emissions means any ton of nitrogen oxides emitted by the CAIR NO_X units at a CAIR NO_X source during a control period that exceeds the CAIR NO_X emissions limitation for the source.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.

General account means a CAIR NO_X Allowance Tracking System account, established under subpart FF of this part, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a cogeneration unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/mmBtu and multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the CAIR designated representative and determined by the Administrator in accordance with subpart HH of this part and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means, starting from the initial installation of a unit, the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as specified by the manufacturer of the unit, or, starting from the completion of any subsequent physical change in the unit resulting in a decrease in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis, such decreased maximum amount as specified by the person conducting the physical change.

Monitoring system means any monitoring system that meets the requirements of subpart HH of this part, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Most stringent State or Federal NO_X emissions limitation means, with regard to a unit, the lowest NO_X emissions limitation (in terms of lb/mmBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as specified by the person conducting the physical change.

Oil-fired means, for purposes of subpart EE of this part, combusting fuel oil for more than 15.0 percent of the annual heat input in a specified year.

Operator means any person who operates, controls, or supervises a CAIR NO_X unit or a CAIR NO_X source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means any of the following persons:

(1) With regard to a CAIR NO_X source or a CAIR NO_X unit at a source, respectively:

(i) Any holder of any portion of the legal or equitable title in a CAIR NO_X unit at the source or the CAIR NO_X unit;

(ii) Any holder of a leasehold interest in a CAIR NO_X unit at the source or the CAIR NO_X unit; or

(iii) Any purchaser of power from a CAIR NO_X unit at the source or the CAIR NO_X unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such CAIR NO_X unit; or

(2) With regard to any general account, any person who has an ownership interest with respect to the CAIR NO_X allowances held in the general account and who is subject to the binding agreement for the CAIR authorized account representative to represent the person's ownership interest with respect to CAIR NO_X allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the CAIR NO_X Annual Trading Program in accordance with subpart CC of this part or, if no such agency has been so authorized, the Administrator.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, *record*, or *recorded* means, with regard to CAIR NO_X allowances, the movement of CAIR NO_X allowances by the Administrator into or between CAIR NO_X Allowance Tracking System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Repowered means, with regard to a unit, replacement of a coal-fired boiler with one of the following coal-fired technologies at the same source as the coal-fired boiler:

(1) Atmospheric or pressurized fluidized bed combustion;

(2) Integrated gasification combined cycle;

(3) Magnetohydrodynamics;

(4) Direct and indirect coal-fired turbines;

(5) Integrated gasification fuel cells; or

(6) As determined by the Administrator in consultation with the Secretary of Energy, a derivative of one or more of the technologies under paragraphs (1) through (5) of this definition and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

Serial number means, for a CAIR NO_X allowance, the unique identification number assigned to each CAIR NO_X allowance by the Administrator.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from

electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. For purposes of section 502(c) of the Clean Air Act, a ''source,'' including a ''source'' with multiple units, shall be considered a single ''facility.''

State means one of the States or the District of Columbia that adopts the CAIR NO_X Annual Trading Program pursuant to § 51.123(o)(1) or (2) of this chapter.

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

(1) In person;

(2) By United States Postal Service; or

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

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

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

Ton means 2,000 pounds. For the purpose of determining compliance with the CAIR NO_X emissions limitation, total tons of nitrogen oxides emissions for a control period shall be calculated as the sum of all recorded hourly emissions (or the mass equivalent of the recorded hourly emission rates) in accordance with subpart HH of this part, but with any remaining fraction of a ton equal to or greater than 0.50 tons deemed to equal one ton and any remaining fraction of a ton less than 0.50 tons deemed to equal zero tons.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself.

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

Unit means a stationary, fossil-fuel-fired boiler or combustion turbine or other stationary, fossil-fuel-fired combustion device.

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

Unit operating hour or *hour of unit operation* means an hour in which a unit combusts any fuel.

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heating application (*e.g.*, space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.*, thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 96.103 Measurements, abbreviations, and acronyms.

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

Btu—British thermal unit.
CO_2—carbon dioxide.
NO_X—nitrogen oxides.
hr—hour.
kW—kilowatt electrical.
kWh—kilowatt hour.
mmBtu—million Btu.
MWe—megawatt electrical.
MWh—megawatt hour.
O_2—oxygen.
ppm—parts per million.
lb—pound.
scfh—standard cubic feet per hour.
SO_2—sulfur dioxide.
H_2O—water.
yr—year.

§ 96.104 Applicability.

The following units in a State shall be CAIR NO_X units, and any source that includes one or more such units shall be a CAIR NO_X source, subject to the requirements of this subpart and subparts BB through HH of this part:

(a) Except as provided in paragraph (b) of this section, a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this section starting on the day on which the unit first no longer qualifies as a cogeneration unit.

§ 96.105 Retired unit exemption.

(a)(1) Any CAIR NO_X unit that is permanently retired and is not a CAIR NO_X opt-in unit under subpart II of this part shall be exempt from the CAIR NO_X Annual Trading Program, except for the provisions of this section, § 96.102, § 96.103, § 96.104, § 96.106(c)(4) through (8), § 96.107, and subparts EE through GG of this part.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the CAIR NO_X unit is permanently retired. Within 30 days of the unit's permanent retirement, the CAIR designated representative shall submit a statement to the permitting authority otherwise responsible for administering any CAIR permit for the unit and shall submit a copy of the statement to the Administrator. The statement shall state, in a format prescribed by the permitting authority, that the unit was permanently retired on a specific date and will comply with the requirements of paragraph (b) of this section.

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

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any nitrogen oxides, starting on the date that the exemption takes effect.

(2) The permitting authority will allocate CAIR NO_X allowances under subpart EE of this part to a unit exempt under paragraph (a) of this section.

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

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

(5) A unit exempt under paragraph (a) of this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the CAIR designated representative of the source submits a complete CAIR permit application under § 96.122 for the unit not less than 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2009 or the date on which the unit resumes operation.

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

(i) The date on which the CAIR designated representative submits a CAIR permit application for the unit under paragraph (b)(5) of this section;

(ii) The date on which the CAIR designated representative is required under paragraph (b)(5) of this section to submit a CAIR permit application for the unit; or

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

(7) For the purpose of applying monitoring, reporting, and recordkeeping requirements under subpart HH of this part, a unit that loses its exemption under paragraph (a) of this section shall be treated as a unit that commences operation and commercial operation on the first date on which the unit resumes operation.

§ 96.106 Standard requirements.

(a) *Permit requirements.* (1) The CAIR designated representative of each CAIR NO_X source required to have a title V operating permit and each CAIR NO_X unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under § 96.122 in accordance with the deadlines specified in § 96.121(a) and (b); and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR NO_X source required to have a title V operating permit and each CAIR NO_X unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart II of this part, the owners and operators of a CAIR NO_X source that is not otherwise required to have a title V operating permit and each CAIR NO_X unit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CC of this part for such CAIR NO_X source and such CAIR NO_X unit.

(b) *Monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the CAIR designated representative, of each CAIR NO_X source and each CAIR NO_X unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HH of this part.

(2) The emissions measurements recorded and reported in accordance with subpart HH of this part shall be used to determine compliance by each CAIR NO_X source with the CAIR NO_X emissions limitation under paragraph (c) of this section.

(c) *Nitrogen oxides emission requirements.* (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall hold, in the source's compliance account, CAIR NO_X allowances available for compliance deductions for the control period under § 96.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X units at the source, as determined in accordance with subpart HH of this part.

(2) A CAIR NO_X unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later of January 1, 2009 or the deadline for meeting the unit's monitor certification requirements under § 96.170(b)(1),(2), or (5).

(3) A CAIR NO_X allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NO_X allowance was allocated.

(4) CAIR NO_X allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Allowance Tracking System accounts in accordance with subpart EE of this part.

(5) A CAIR NO_X allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_X Annual Trading Program. No provision of the CAIR NO_X Annual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under § 96.105 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR NO_X allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart FF, GG, or II of this part, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from a CAIR NO_X unit's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR NO_X unit.

(d) *Excess emissions requirements.* (1) If a CAIR NO_X source emits nitrogen oxides during any control period in excess of the CAIR NO_X emissions limitation, then:

(i) The owners and operators of the source and each CAIR NO_X unit at the source shall surrender the CAIR NO_X allowances required for deduction under § 96.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(ii) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(2) [Reserved.]

(e) *Recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of the CAIR NO_X source and each CAIR NO_X unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under § 96.113 for the CAIR designated representative for the source and each CAIR NO_X unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under § 96.113 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subpart HH of this part, provided that to the extent that subpart HH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X Annual Trading Program.

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_X Annual Trading Program or to demonstrate compliance with the requirements of the CAIR NO_X Annual Trading Program.

(2) The CAIR designated representative of a CAIR NO_X source and each CAIR NO_X unit at the source shall submit the reports required under the CAIR NO_X Annual Trading Program, including those under subpart HH of this part.

(f) *Liability.* (1) Each CAIR NO_X source and each CAIR NO_X unit shall meet the requirements of the CAIR NO_X Annual Trading Program.

(2) Any provision of the CAIR NO_X Annual Trading Program that applies to a CAIR NO_X source or the CAIR designated representative of a CAIR NO_X source shall also apply to the owners and operators of such source and of the CAIR NO_X units at the source.

(3) Any provision of the CAIR NO_X Annual Trading Program that applies to a CAIR NO_X unit or the CAIR designated representative of a CAIR NO_X unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the CAIR NO_X Annual Trading Program, a CAIR permit application, a CAIR permit, or an exemption under § 96.105 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X source or CAIR NO_X unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 96.107 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CAIR NO_X Annual Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CAIR NO_X Annual Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CAIR NO_X Annual Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 96.108 Appeal procedures.

The appeal procedures for decisions of the Administrator under the CAIR NO_X Annual Trading Program are set forth in part 78 of this chapter.

Subpart BB—CAIR Designated Representative for CAIR NO_X Sources

§ 96.110 Authorization and responsibilities of CAIR designated representative.

(a) Except as provided under § 96.111, each CAIR NO_X source, including all CAIR NO_X units at the source, shall have one and only one CAIR designated representative, with regard to all matters under the CAIR NO_X Annual Trading Program concerning the source or any CAIR NO_X unit at the source.

(b) The CAIR designated representative of the CAIR NO_X source shall be selected by an agreement binding on the owners and operators of the source and all CAIR NO_X units at the source and shall act in accordance with the certification statement in § 96.113(a)(4)(iv).

(c) Upon receipt by the Administrator of a complete certificate of representation under § 96.113, the CAIR designated representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the CAIR NO_X source represented and each CAIR NO_X unit at the source in all matters pertaining to the CAIR NO_X Annual Trading Program, notwithstanding any agreement between the CAIR designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CAIR designated representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No CAIR permit will be issued, no emissions data reports will be accepted, and no CAIR NO_X Allowance Tracking System account will be established for a CAIR NO_X unit at a source, until the Administrator has received a complete certificate of representation under § 96.113 for a CAIR designated representative of the source and the CAIR NO_X units at the source.

(e)(1) Each submission under the CAIR NO_X Annual Trading Program shall be submitted, signed, and certified by the CAIR designated representative for each CAIR NO_X source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CAIR designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) The permitting authority and the Administrator will accept or act on a submission made on behalf of owner or operators of a CAIR NO_X source or a CAIR NO_X unit only if the submission has been made, signed, and certified in accordance with paragraph (e)(1) of this section.

§ 96.111 Alternate CAIR designated representative.

(a) A certificate of representation under § 96.113 may designate one and only one alternate CAIR designated representative, who may act on behalf of the CAIR designated representative. The agreement by which the alternate CAIR designated representative is selected shall include a procedure for authorizing the alternate CAIR designated representative to act in lieu of the CAIR designated representative.

(b) Upon receipt by the Administrator of a complete certificate of representation under § 96.113, any representation, action, inaction, or submission by the alternate CAIR designated representative shall be deemed to be a representation, action, inaction, or submission by the CAIR designated representative.

(c) Except in this section and §§ 96.102, 96.110(a) and (d), 96.112, 96.113, 96.151 and 96.182, whenever the term ''CAIR designated representative'' is used in subparts AA through II of this part, the term shall be construed to include the CAIR designated representative or any alternate CAIR designated representative.

§ 96.112 Changing CAIR designated representative and alternate CAIR designated representative; changes in owners and operators.

(a) *Changing CAIR designated representative.* The CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 96.113. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new CAIR designated representative and the owners and operators of the CAIR NO_X source and the CAIR NO_X units at the source.

(b) *Changing alternate CAIR designated representative.* The alternate CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 96.113. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate CAIR designated representative and the owners and operators of the CAIR NO_X source and the CAIR NO_X units at the source.

(c) *Changes in owners and operators.* (1) In the event a new owner or operator of a CAIR NO_X source or a CAIR NO_X unit is not included in the list of owners and operators in the certificate of representation under § 96.113, such new owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the CAIR designated representative and any alternate CAIR designated representative of the source or unit, and the decisions and orders of the permitting authority, the Administrator, or a court, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a CAIR NO_X source or a CAIR NO_X unit, including the addition of a new owner or operator, the CAIR designated representative or any alternate CAIR designated representative shall submit a revision to the certificate of representation under § 96.113 amending the list of owners and operators to include the change.

§ 96.113 Certificate of representation.

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

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

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

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

(4) The following certification statements by the CAIR designated representative and any alternate CAIR designated representative—

(i) ''I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CAIR NO_X unit at the source.''

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR NO_X Annual Trading Program on behalf of the owners and operators of the source and of each CAIR NO_X unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.''

(iii) ''I certify that the owners and operators of the source and of each CAIR NO_X unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.''

(iv) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO_X unit, or where a customer purchases power from a CAIR NO_X unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'CAIR designated representative' or 'alternate CAIR designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CAIR NO_X unit at the source; and CAIR NO_X allowances and proceeds of transactions involving CAIR NO_X allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_X allowances by contract, CAIR NO_X allowances and proceeds of transactions involving CAIR NO_X allowances will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the CAIR designated representative and any alternate CAIR designated representative and the dates signed.

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

§ 96.114 Objections concerning CAIR designated representative.

(a) Once a complete certificate of representation under § 96.113 has been submitted and received, the permitting authority and the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 96.113 is received by the Administrator.

(b) Except as provided in § 96.112(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the CAIR designated representative shall affect any representation, action, inaction, or submission of the CAIR designated representative or the finality of any decision or order by the permitting authority or the Administrator under the CAIR NO_X Annual Trading Program.

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

Subpart CC—Permits

§ 96.120 General CAIR Annual Trading Program permit requirements.

(a) For each CAIR NO_X source required to have a title V operating permit or required, under subpart II of this part, to have a title V operating permit or other federally enforceable permit, such permit shall include a CAIR permit administered by the permitting authority for the title V operating permit or the federally enforceable permit as applicable. The CAIR portion of the title V permit or other federally enforceable permit as applicable shall be administered in accordance with the permitting authority's title V operating permits regulations promulgated under part 70 or 71 of this chapter or the permitting authority's regulations for other federally enforceable permits as applicable, except as provided otherwise by this subpart and subpart II of this part.

(b) Each CAIR permit shall contain, with regard to the CAIR NO_X source and the CAIR NO_X units at the source covered by the CAIR permit, all applicable CAIR NO_X Annual Trading Program, CAIR NO_X Ozone Season Trading Program, and CAIR SO_2 Trading Program requirements and shall be a complete and separable portion of the title V operating permit or other federally enforceable permit under paragraph (a) of this section.

§ 96.121 Submission of CAIR permit applications.

(a) *Duty to apply.* The CAIR designated representative of any CAIR NO_X source required to have a title V operating permit shall submit to the permitting authority a complete CAIR permit application under § 96.122 for the source covering each CAIR NO_X unit at the source at least 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2009 or the date on which the CAIR NO_X unit commences operation.

(b) *Duty to Reapply.* For a CAIR NO_X source required to have a title V operating permit, the CAIR designated representative shall submit a complete CAIR permit application under § 96.122 for the source covering each CAIR NO_X unit at the source to renew the CAIR permit in accordance with the permitting authority's title V operating permits regulations addressing permit renewal.

§ 96.122 Information requirements for CAIR permit applications.

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

(a) Identification of the CAIR NO_X source;

(b) Identification of each CAIR NO_X unit at the CAIR NO_X source; and

(c) The standard requirements under § 96.106.

§ 96.123 CAIR permit contents and term.

(a) Each CAIR permit will contain, in a format prescribed by the permitting authority, all elements required for a complete CAIR permit application under § 96.122.

(b) Each CAIR permit is deemed to incorporate automatically the definitions of terms under § 96.102 and, upon recordation by the Administrator under subpart FF, GG, or II of this part, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from the compliance account of the CAIR NO_X source covered by the permit.

(c) The term of the CAIR permit will be set by the permitting authority, as necessary to facilitate coordination of the renewal of the CAIR permit with issuance, revision, or renewal of the CAIR NO_X source's title V operating permit or other federally enforceable permit as applicable.

§ 96.124 CAIR permit revisions.

Except as provided in § 96.123(b), the permitting authority will revise the CAIR permit, as necessary, in accordance with the permitting authority's title V operating permits regulations or the permitting authority's regulations for other federally enforceable permits as applicable addressing permit revisions.

Subpart DD—[Reserved]

Subpart EE—CAIR NO_X Allowance Allocations

§ 96.140 State trading budgets.

The State trading budgets for annual allocations of CAIR NO_X allowances for the control periods in 2009 through 2014 and in 2015 and thereafter are respectively as follows:

State	State trading budget for 2009–2014 (tons)	State trading budget for 2015 and thereafter (tons)
Alabama	69,020	57,517
District of Columbia	144	120
Florida	99,445	82,871
Georgia	66,321	55,268
Illinois	76,230	63,525
Indiana	108,935	90,779
Iowa	32,692	27,243
Kentucky	83,205	69,337
Louisiana	35,512	29,593
Maryland	27,724	23,104
Michigan	65,304	54,420
Minnesota	31,443	26,203
Mississippi	17,807	14,839
Missouri	59,871	49,892
New York	45,617	38,014
North Carolina	62,183	51,819
Ohio	108,667	90,556
Pennsylvania	99,049	82,541
South Carolina	32,662	27,219
Tennessee	50,973	42,478
Texas	181,014	150,845

State	State trading budget for 2009–2014 (tons)	State trading budget for 2015 and thereafter (tons)
Virginia	36,074	30,062
West Virginia	74,220	61,850
Wisconsin	40,759	33,966

§ 96.141 Timing requirements for CAIR NO_X allowance allocations.

(a) By October 31, 2006, the permitting authority will submit to the Administrator the CAIR NO_X allowance allocations, in a format prescribed by the Administrator and in accordance with § 96.142(a) and (b), for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014.

(b)(1) By October 31, 2009 and October 31 of each year thereafter, the permitting authority will submit to the Administrator the CAIR NO_X allowance allocations, in a format prescribed by the Administrator and in accordance with § 96.142(a) and (b), for the control period in the sixth year after the year of the applicable deadline for submission under this paragraph.

(2) If the permitting authority fails to submit to the Administrator the CAIR NO_X allowance allocations in accordance with paragraph (b)(1) of this section, the Administrator will assume that the allocations of CAIR NO_X allowances for the applicable control period are the same as for the control period that immediately precedes the applicable control period, except that, if the applicable control period is in 2015, the Administrator will assume that the allocations equal 83 percent of the allocations for the control period that immediately precedes the applicable control period.

(c)(1) By October 31, 2009 and October 31 of each year thereafter, the permitting authority will submit to the Administrator the CAIR NO_X allowance allocations, in a format prescribed by the Administrator and in accordance with § 96.142(a), (c), and (d), for the control period in the year of the applicable deadline for submission under this paragraph.

(2) If the permitting authority fails to submit to the Administrator the CAIR NO_X allowance allocations in accordance with paragraph (c)(1) of this section, the Administrator will assume that the allocations of CAIR NO_X allowances for the applicable control period are the same as for the control period that immediately precedes the applicable control period, except that, if the applicable control period is in 2015, the Administrator will assume that the allocations equal 83 percent of the allocations for the control period that immediately precedes the applicable control period and except that any CAIR NO_X unit that would otherwise be allocated CAIR NO_X allowances under § 96.142(a) and (b), as well as under § 96.142(a), (c), and (d), for the applicable control period will be assumed to be allocated no CAIR NO_X allowances under § 96.142(a), (c), and (d) for the applicable control period.

§ 96.142 CAIR NO_X allowance allocations.

(a)(1) The baseline heat input (in mmBtu) used with respect to CAIR NO_X allowance allocations under paragraph (b) of this section for each CAIR NO_X unit will be:

(i) For units commencing operation before January 1, 2001 the average of the 3 highest amounts of the unit's adjusted control period heat input for 2000 through 2004, with the adjusted control period heat input for each year calculated as follows:

(A) If the unit is coal-fired during the year, the unit's control period heat input for such year is multiplied by 100 percent;

(B) If the unit is oil-fired during the year, the unit's control period heat input for such year is multiplied by 60 percent; and

(C) If the unit is not subject to paragraph (a)(1)(i)(A) or (B) of this section, the unit's control period heat input for such year is multiplied by 40 percent.

(ii) For units commencing operation on or after January 1, 2001 and operating each calendar year during a period of 5 or more consecutive calendar years, the average of the 3 highest amounts of the unit's total converted control period heat input over the first such 5 years.

(2)(i) A unit's control period heat input, and a unit's status as coal-fired or oil-fired, for a calendar year under paragraph (a)(1)(i) of this section, and a unit's total tons of NO_X emissions during a calendar year under paragraph (c)(3) of this section, will be determined in accordance with part 75 of this chapter, to the extent the unit was otherwise subject to the requirements of part 75 of this chapter for the year, or will be based on the best available data reported to the permitting authority for the unit, to the extent the unit was not otherwise subject to the requirements of part 75 of this chapter for the year.

(ii) A unit's converted control period heat input for a calendar year specified under paragraph (a)(1)(ii) of this section equals:

(A) Except as provided in paragraph (a)(2)(ii)(B) or (C) of this section, the control period gross electrical output of the generator or generators served by the unit multiplied by 7,900 Btu/kWh, if the unit is coal-fired for the year, or 6,675 Btu/kWh, if the unit is not coal-fired for the year, and divided by 1,000,000 Btu/mmBtu, provided that if a generator is served by 2 or more units, then the gross electrical output of the generator will be attributed to each unit in proportion to the unit's share of the total control period heat input of such units for the year;

(B) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the total heat energy (in Btu) of the steam produced by the boiler during the control period, divided by 0.8 and by 1,000,000 Btu/mmBtu; or

(C) For a unit that is a combustion turbine and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the control period gross electrical output of the enclosed device comprising the compressor, combustor, and turbine multiplied by 3,414 Btu/kWh, plus the total heat energy (in Btu) of the steam produced by any associated heat recovery steam generator during the control period divided by 0.8, and with the sum divided by 1,000,000 Btu/mmBtu.

(b)(1) For each control period in 2009 and thereafter, the permitting authority will allocate to all CAIR NO_X units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of CAIR NO_X allowances equal to 95 percent for a control period during 2009 through 2014, and 97 percent for a control period during 2015 and thereafter, of the tons of NO_X emissions in the State trading budget under § 96.140 (except as provided in paragraph (d) of this section).

(2) The permitting authority will allocate CAIR NO_X allowances to each CAIR NO_X unit under paragraph (b)(1) of this section in an amount determined by multiplying the total amount of CAIR NO_X allowances allocated under paragraph (b)(1) of this section by the ratio of the baseline heat input of such CAIR NO_X unit to the total amount of baseline heat input of all such CAIR NO_X units in the State and rounding to the nearest whole allowance as appropriate.

(c) For each control period in 2009 and thereafter, the permitting authority will allocate CAIR NO_X allowances to CAIR NO_X units in the State that commenced operation on or after January 1, 2001 and do not yet have a baseline heat input (as determined under paragraph (a) of this section), in accordance with the following procedures:

(1) The permitting authority will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated CAIR NO_X allowances equal to 5 percent for a control period in 2009 through 2013, and 3 percent for a control period in 2014 and thereafter, of the amount of tons of NO_X emissions in the State trading budget under § 96.140.

(2) The CAIR designated representative of such a CAIR NO_X unit may submit to the permitting authority a request, in a format specified by the permitting authority, to be allocated CAIR NO_X allowances, starting with the later of the control period in 2009 or the first control period after the control period in which the CAIR NO_X unit commences commercial operation and until the first control period for which the unit is allocated CAIR NO_X allowances under paragraph (b) of this section. The CAIR NO_X allowance allocation request must be submitted on or before July 1 of the first control period for which the CAIR NO_X allowances are requested and after the date on which the CAIR NO_X unit commences commercial operation.

(3) In a CAIR NO_X allowance allocation request under paragraph (c)(2) of this section, the CAIR designated representative may request for a control period CAIR NO_X allowances in an amount not exceeding the CAIR NO_X unit's total tons of NO_X emissions during the calendar year immediately before such control period.

(4) The permitting authority will review each CAIR NO_X allowance allocation request under paragraph (c)(2) of this section and will allocate CAIR NO_X allowances for each control period pursuant to such request as follows:

(i) The permitting authority will accept an allowance allocation request only if the request meets, or is adjusted by the permitting authority as necessary to meet, the requirements of paragraphs (c)(2) and (3) of this section.

(ii) On or after July 1 of the control period, the permitting authority will determine the sum of the CAIR NO_X allowances requested (as adjusted under paragraph (c)(4)(i) of this section) in all allowance allocation requests accepted under paragraph (c)(4)(i) of this section for the control period.

(iii) If the amount of CAIR NO_X allowances in the new unit set-aside for the control period is greater than or equal to the sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate the amount of CAIR NO_X allowances requested (as adjusted under paragraph (c)(4)(i) of this section) to each CAIR NO_X unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section.

(iv) If the amount of CAIR NO_X allowances in the new unit set-aside for the control period is less than the sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate to each CAIR NO_X unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the CAIR NO_X allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of CAIR NO_X allowances in the new unit set-aside for the control period, divided by the sum determined under paragraph (c)(4)(ii) of this section, and rounded to the nearest whole allowance as appropriate.

(v) The permitting authority will notify each CAIR designated representative that submitted an allowance allocation request of the amount of CAIR NO_X allowances (if any) allocated for the control period to the CAIR NO_X unit covered by the request.

(d) If, after completion of the procedures under paragraph (c)(4) of this section for a control period, any unallocated CAIR NO_X allowances remain in the new unit set-aside for the control period, the permitting authority will allocate to each CAIR NO_X unit that was allocated CAIR NO_X allowances under paragraph (b) of this section an amount of CAIR NO_X allowances equal to the total amount of such remaining unallocated CAIR NO_X allowances, multiplied by the unit's allocation under paragraph (b) of this section, divided by 95 percent for a control period during 2009 through 2014, and 97 percent for a control period during 2015 and thereafter, of the amount of tons of NO_X emissions in the State trading budget under § 96.140, and rounded to the nearest whole allowance as appropriate.

§ 96.143 Compliance supplement pool.

(a) In addition to the CAIR NO_X allowances allocated under § 96.142, the permitting authority may allocate for the control period in 2009 up to the following amount of CAIR NO_X allowances to CAIR NO_X units in the respective State:

State	Compliance supplement pool
Alabama	10,166
District Of Columbia	0
Florida	8,335
Georgia	12,397
Illinois	11,299
Indiana	20,155
Iowa	6,978
Kentucky	14,935
Louisiana	2,251
Maryland	4,670
Michigan	8,347
Minnesota	6,528
Mississippi	3,066
Missouri	9,044
New York	0
North Carolina	0
Ohio	25,037
Pennsylvania	16,009
South Carolina	2,600
Tennessee	8,944
Texas	772
Virginia	5,134
West Virginia	16,929
Wisconsin	4,898

(b) For any CAIR NO_X unit in the State that achieves NO_X emission reductions in 2007 and 2008 that are not necessary to comply with any State or federal emissions limitation applicable during such years, the CAIR designated representative of the unit may request early reduction credits, and allocation of CAIR NO_X allowances from the compliance supplement pool under paragraph (a) of this section for such early reduction credits, in accordance with the following:

(1) The owners and operators of such CAIR NO_X unit shall monitor and report the NO_X emissions rate and the heat input of the unit in accordance with subpart HH of this part in each control period for which early reduction credit is requested.

(2) The CAIR designated representative of such CAIR NO_X unit shall submit to the permitting authority by July 1, 2009 a request, in a format specified by the permitting authority, for allocation of an amount of CAIR NO_X allowances from the compliance supplement pool not exceeding the sum of the amounts (in tons) of the unit's

NO_X emission reductions in 2007 and 2008 that are not necessary to comply with any State or federal emissions limitation applicable during such years, determined in accordance with subpart HH of this part.

(c) For any CAIR NO_X unit in the State whose compliance with CAIR NO_X emissions limitation for the control period in 2009 would create an undue risk to the reliability of electricity supply during such control period, the CAIR designated representative of the unit may request the allocation of CAIR NO_X allowances from the compliance supplement pool under paragraph (a) of this section, in accordance with the following:

(1) The CAIR designated representative of such CAIR NO_X unit shall submit to the permitting authority by July 1, 2009 a request, in a format specified by the permitting authority, for allocation of an amount of CAIR NO_X allowances from the compliance supplement pool not exceeding the minimum amount of CAIR NO_X allowances necessary to remove such undue risk to the reliability of electricity supply.

(2) In the request under paragraph (c)(1) of this section, the CAIR designated representative of such CAIR NO_X unit shall demonstrate that, in the absence of allocation to the unit of the amount of CAIR NO_X allowances requested, the unit's compliance with CAIR NO_X emissions limitation for the control period in 2009 would create an undue risk to the reliability of electricity supply during such control period. This demonstration must include a showing that it would not be feasible for the owners and operators of the unit to:

(i) Obtain a sufficient amount of electricity from other electricity generation facilities, during the installation of control technology at the unit for compliance with the CAIR NO_X emissions limitation, to prevent such undue risk; or

(ii) Obtain under paragraphs (b) and (d) of this section, or otherwise obtain, a sufficient amount of CAIR NO_X allowances to prevent such undue risk.

(d) The permitting authority will review each request under paragraph (b) or (c) of this section submitted by July 1, 2009 and will allocate CAIR NO_X allowances for the control period in 2009 to CAIR NO_X units in the State and covered by such request as follows:

(1) Upon receipt of each such request, the permitting authority will make any necessary adjustments to the request to ensure that the amount of the CAIR NO_X allowances requested meets the requirements of paragraph (b) or (c) of this section.

(2) If the State's compliance supplement pool under paragraph (a) of this section has an amount of CAIR NO_X allowances not less than the total amount of CAIR NO_X allowances in all such requests (as adjusted under paragraph (d)(1) of this section), the permitting authority will allocate to each CAIR NO_X unit covered by such requests the amount of CAIR NO_X allowances requested (as adjusted under paragraph (d)(1) of this section).

(3) If the State's compliance supplement pool under paragraph (a) of this section has a smaller amount of CAIR NO_X allowances than the total amount of CAIR NO_X allowances in all such requests (as adjusted under paragraph (d)(1) of this section), the permitting authority will allocate CAIR NO_X allowances to each CAIR NO_X unit covered by such requests according to the following formula and rounding to the nearest whole allowance as appropriate:

Unit's allocation = Unit's adjusted allocation × (State's compliance supplement pool ÷ Total adjusted allocations for all units)

Where:

''Unit's allocation'' is the number of CAIR NO_X allowances allocated to the unit from the State's compliance supplement pool. Unit's adjusted allocation'' is the amount of CAIR NO_X allowances requested for the unit under paragraph (b) or (c) of this section, as adjusted under paragraph (d)(1) of this section. ''State's compliance supplement pool'' is the amount of CAIR NO_X allowances in the State's compliance supplement pool. ''Total adjusted allocations for all units'' is the sum of the amounts of allocations requested for all units under paragraph (b) or (c) of this section, as adjusted under paragraph (d)(1) of this section.

(4) By November 30, 2009, the permitting authority will determine, and submit to the Administrator, the allocations under paragraph (d)(3) or (4) of this section.

(5) By January 1, 2010, the Administrator will record the allocations under paragraph (d)(5) of this section.

Subpart FF—CAIR NO_X Allowance Tracking System

§ 96.150 [Reserved]

§ 96.151 Establishment of accounts.

(a) *Compliance accounts.* Except as provided in § 96.184(e), upon receipt of a complete certificate of representation under § 96.113, the Administrator will establish a compliance account for the CAIR NO_X source for which the certificate of representation was submitted unless the source already has a compliance account.

(b) *General accounts.* (1) *Application for general account.*

(i) Any person may apply to open a general account for the purpose of holding and transferring CAIR NO_X allowances. An application for a general account may designate one and only one CAIR authorized account representative and one and only one alternate CAIR authorized account representative who may act on behalf of the CAIR authorized account representative. The agreement by which the alternate CAIR authorized account representative is selected shall include a procedure for authorizing the alternate CAIR authorized account representative to act in lieu of the CAIR authorized account representative.

(ii) A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR authorized account representative and any alternate CAIR authorized account representative;

(B) Organization name and type of organization, if applicable;

(C) A list of all persons subject to a binding agreement for the CAIR authorized account representative and any alternate CAIR authorized account representative to represent their ownership interest with respect to the CAIR NO_X allowances held in the general account;

(D) The following certification statement by the CAIR authorized account representative and any alternate CAIR authorized account representative: ''I certify that I was selected as the CAIR authorized account representative or the alternate CAIR authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CAIR NO_X allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR NO_X Annual Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account.''

(E) The signature of the CAIR authorized account representative and any alternate CAIR authorized account representative and the dates signed.

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

(2) *Authorization of CAIR authorized account representative.*

(i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(A) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(B) The CAIR authorized account representative and any alternate CAIR authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CAIR NO_X allowances held in the general account in all matters pertaining to the CAIR NO_X Annual Trading Program, notwithstanding any agreement between the CAIR authorized account representative or any alternate CAIR authorized account representative and such person. Any such person shall be bound by any order or decision issued to the CAIR authorized account representative or any alternate CAIR authorized account representative by the Administrator or a court regarding the general account.

(C) Any representation, action, inaction, or submission by any alternate CAIR authorized account representative shall be deemed to be a representation, action, inaction, or submission by the CAIR authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the CAIR authorized account representative or any alternate CAIR authorized account representative for the persons having an ownership interest with respect to CAIR NO_X allowances held in the general account. Each such submission shall include the following certification statement by the CAIR authorized account representative or any alternate CAIR authorized account representative: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CAIR NO_X allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iii) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(ii) of this section.

(3) *Changing CAIR authorized account representative and alternate CAIR authorized account representative; changes in persons with ownership interest.*

(i) The CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR NO_X allowances in the general account.

(ii) The alternate CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR NO_X allowances in the general account.

(iii)(A) In the event a new person having an ownership interest with respect to CAIR NO_X allowances in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the CAIR authorized account representative and any alternate CAIR authorized account representative of the account, and the decisions and orders of the Administrator or a court, as if the new person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to CAIR NO_X allowances in the general account, including the addition of persons, the CAIR authorized account representative or any alternate CAIR authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CAIR NO_X allowances in the general account to include the change.

(4) *Objections concerning CAIR authorized account representative.*

(i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative for a general account shall affect any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative or the finality of any decision or order by the Administrator under the CAIR NO_X Annual Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative for a general account, including private legal disputes concerning the proceeds of CAIR NO_X allowance transfers.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

§ 96.152 Responsibilities of CAIR authorized account representative.

Following the establishment of a CAIR NO_X Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CAIR NO_X allowances in the account, shall be made only by the CAIR authorized account representative for the account.

§ 96.153 Recordation of CAIR NO_X allowance allocations.

(a) By December 1, 2006, the Administrator will record in the CAIR NO_X source's compliance account the CAIR NO_X allowances allocated for the CAIR NO_X units at a source, as submitted by the permitting authority in accordance with § 96.141(a), for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014.

(b) By December 1, 2009, the Administrator will record in the CAIR NO_X source's compliance account the CAIR NO_X allowances allocated for the CAIR NO_X units at the source, as submitted by the permitting authority or as determined by the Administrator in accordance with § 96.141(b), for the control period in 2015.

(c) In 2011 and each year thereafter, after the Administrator has made all deductions (if any) from a CAIR NO_X source's compliance account under § 96.154, the Administrator will record in the CAIR NO_X source's compliance account the CAIR NO_X allowances allocated for the CAIR NO_X units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with § 96.141(b), for the control period in the sixth year after the year of the control period for which such deductions were or could have been made.

(d) By December 1, 2009 and December 1 of each year thereafter, the Administrator will record in the CAIR NO_X source's compliance account the CAIR NO_X allowances allocated for the CAIR NO_X units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with § 96.141(c), for the control period in the year of the applicable deadline for recordation under this paragraph.

(e) *Serial numbers for allocated CAIR NO_X allowances. When recording the allocation of CAIR NO_X* allowances for a CAIR NO_X unit in a compliance account, the Administrator will assign each CAIR NO_X allowance a unique identification number that will include digits identifying the year of the control period for which the CAIR NO_X allowance is allocated.

§ 96.154 Compliance with CAIR NO_X emissions limitation.

(a) *Allowance transfer deadline.* The CAIR NO_X allowances are available to be deducted for compliance with a source's CAIR NO_X emissions limitation for a control period in a given calendar year only if the CAIR NO_X allowances:

(1) Were allocated for the control period in the year or a prior year;

(2) Are held in the compliance account as of the allowance transfer deadline for the control period or are transferred into the compliance account by a CAIR NO_X allowance transfer correctly submitted for recordation under § 96.160 by the allowance transfer deadline for the control period; and

(3) Are not necessary for deductions for excess emissions for a prior control period under paragraph (d) of this section.

(b) *Deductions for compliance.* Following the recordation, in accordance with § 96.161, of CAIR NO_X allowance transfers submitted for recordation in a source's compliance account by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account CAIR NO_X allowances available under paragraph (a) of this section in order to determine whether the source meets the CAIR NO_X emissions limitation for the control period, as follows:

(1) Until the amount of CAIR NO_X allowances deducted equals the number of tons of total nitrogen oxides emissions, determined in accordance with subpart HH of this part, from all CAIR NO_X units at the source for the control period; or

(2) If there are insufficient CAIR NO_X allowances to complete the deductions in paragraph (b)(1) of this section, until no more CAIR NO_X allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of CAIR NO_X allowances by serial number. The CAIR authorized account representative for a source's compliance account may request that specific CAIR NO_X* allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the Administrator by the allowance transfer deadline for the control period and include, in a format prescribed by the Administrator, the identification of the CAIR NO_X source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct CAIR NO_X allowances under paragraph (b) or (d) of this section from the source's compliance account, in the absence of an identification or in the case of a partial identification of CAIR NO_X allowances by serial number under paragraph (c)(1) of this section, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any CAIR NO_X allowances that were allocated to the units at the source, in the order of recordation; and then

(ii) Any CAIR NO_X allowances that were allocated to any unit and transferred and recorded in the compliance account pursuant to subpart GG of this part, in the order of recordation.

(d) *Deductions for excess emissions.*

(1) After making the deductions for compliance under paragraph (b) of this section for a control period in a calendar year in which the CAIR NO_X source has excess emissions, the Administrator will deduct from the source's compliance account an amount of CAIR NO_X allowances, allocated for the control period in the immediately following calendar year, equal to 3 times the number of tons of the source's excess emissions.

(2) Any allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the CAIR NO_X source or the CAIR NO_X units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violations, as ordered under the Clean Air Act or applicable State law.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) or (d) of this section.

(f) *Administrator's action on submissions.*

(1) The Administrator may review and conduct independent audits concerning any submission under the CAIR NO_X Annual Trading Program and make appropriate adjustments of the information in the submissions.

(2) The Administrator may deduct CAIR NO_X allowances from or transfer CAIR NO_X allowances to a source's compliance account based on the information in the submissions, as adjusted under paragraph (f)(1) of this section.

§ 96.155 Banking.

(a) CAIR NO_X allowances may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any CAIR NO_X allowance that is held in a compliance account or a general account will remain in such account unless and until the CAIR NO_X allowance is deducted or transferred under § 96.154, § 96.156, or subpart GG of this part.

§ 96.156 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any CAIR NO_X Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the CAIR authorized account representative for the account.

§ 96.157 Closing of general accounts.

(a) The CAIR authorized account representative of a general account may submit to the Administrator a request to close the account, which shall include a correctly submitted allowance transfer under § 96.160 for any CAIR NO_X allowances in the account to one or more other CAIR NO_X Allowance Tracking System accounts.

(b) If a general account has no allowance transfers in or out of the account for a 12-month period or longer and does not contain any CAIR NO_X allowances, the Administrator may notify the CAIR authorized account representative for the account that the account will be closed following 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted transfer of CAIR NO_X allowances into the account under § 96.160 or a statement submitted by the CAIR authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

Subpart GG—CAIR NO_X Allowance Transfers

§ 96.160 Submission of CAIR NO_X allowance transfers.

A CAIR authorized account representative seeking recordation of a CAIR NO_X allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the CAIR NO_X allowance transfer shall include the following elements, in a format specified by the Administrator:

(a) The account numbers for both the transferor and transferee accounts;

(b) The serial number of each CAIR NO_X allowance that is in the transferor account and is to be transferred; and

(c) The name and signature of the CAIR authorized account representative of the transferor account and the date signed.

§ 96.161 EPA recordation.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a CAIR NO_X allowance transfer, the Administrator will record a CAIR NO_X allowance transfer by moving each CAIR NO_X allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under § 96.160; and

(2) The transferor account includes each CAIR NO_X allowance identified by serial number in the transfer.

(b) A CAIR NO_X allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any CAIR NO_X allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 96.154 for the control period immediately before such allowance transfer deadline.

(c) Where a CAIR NO_X allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§ 96.162 Notification.

(a) *Notification of recordation.* Within 5 business days of recordation of a CAIR NO_X allowance transfer under § 96.161, the Administrator will notify the CAIR authorized account representatives of both the transferor and transferee accounts.

(b) *Notification of non-recordation.* Within 10 business days of receipt of a CAIR NO_X allowance transfer that fails to meet the requirements of § 96.161(a), the Administrator will notify the CAIR authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a CAIR NO_X allowance transfer for recordation following notification of non-recordation.

Subpart HH—Monitoring and Reporting

§ 96.170 General requirements.

The owners and operators, and to the extent applicable, the CAIR designated representative, of a CAIR NO_X unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and in subpart H of part 75 of this chapter. For purposes of complying with such requirements, the definitions in § 96.102 and in § 72.2 of this chapter shall apply, and the terms ''affected unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') in part 75 of this chapter shall be deemed to refer to the terms ''CAIR NO_X unit,'' ''CAIR designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') respectively, as defined in § 96.102. The owner or operator of a unit that is not a CAIR NO_X unit but that is monitored under § 75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a CAIR NO_X unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each CAIR NO_X unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO_X mass emissions and individual unit heat input (including all systems required to monitor NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under § 96.171 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* The owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a CAIR NO_X unit that commences commercial operation before July 1, 2007, by January 1, 2008.

(2) For the owner or operator of a CAIR NO_X unit that commences commercial operation on or after July 1, 2007, by the later of the following dates:

(i) January 1, 2008; or

(ii) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

(3) For the owner or operator of a CAIR NO_X unit for which construction of a new stack or flue or installation of add-on NO_X emission controls is completed after the applicable deadline under paragraph (b)(1), (2), (4), or (5) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO_X emissions controls.

(4) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, by the date specified in § 96.184(b).

(5) Notwithstanding the dates in paragraphs (b)(1), (2), and (4) of this section and solely for purposes of § 96.106(c)(2), for the owner or operator of a CAIR NO_X opt-in unit under subpart II of this part, by the date on which the CAIR NO_X opt-in unit enters the CAIR NO_X Annual Trading Program as provided in § 96.184(g).

(c) *Reporting data.* (1) Except as provided in paragraph (c)(2) of this section, the owner or operator of a CAIR NO_X unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NO_X concentration, NO_X emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NO_X mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(2) The owner or operator of a CAIR NO_X unit that does not meet the applicable compliance date set forth in paragraph (b)(3) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report substitute data using the applicable missing data procedures in subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter, in lieu of the maximum potential (or, as appropriate, minimum potential) values, for a parameter if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation under paragraph (b)(3) of this section.

(d) *Prohibitions.* (1) No owner or operator of a CAIR NO_X unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 96.175.

(2) No owner or operator of a CAIR NO_X unit shall operate the unit so as to discharge, or allow to be discharged, NO_X emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

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

(4) No owner or operator of a CAIR NO_X unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 96.105 that is in effect;

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

(iii) The CAIR designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 96.171(d)(3)(i).

§ 96.171 Initial certification and recertification procedures.

(a) The owner or operator of a CAIR NO_X unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 96.170(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendix B, appendix D, and appendix E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 96.170(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under § 75.17(a) or (b) of this chapter for apportioning the NO_X emission rate measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.12, § 75.17, or subpart H of part 75 of this chapter, the CAIR designated representative shall resubmit the petition to the Administrator under § 96.175(a) to determine whether the approval applies under the CAIR NO_X Annual Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a CAIR NO_X unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (*i.e.*, a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under § 96.170(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under § 96.170(a)(1)(including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 96.170(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission

monitoring system under § 96.170(a)(1) that may significantly affect the ability of the system to accurately measure or record NO_X mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system, and any excepted NO_X monitoring system under appendix E to part 75 of this chapter, under § 96.170(a)(1) are subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* Paragraphs (d)(3)(i) through (iv) of this section apply to both initial certification and recertification of a continuous monitoring system under § 96.170(a)(1). For recertifications, replace the words ''certification'' and ''initial certification'' with the word ''recertification'', replace the word ''certified'' with the word ''recertified,'' and follow the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter in lieu of the procedures in paragraph (d)(3)(v) of this section.

(i) *Notification of certification.* The CAIR designated representative shall submit to the permitting authority, the appropriate EPA Regional Office, and the Administrator written notice of the dates of certification testing, in accordance with § 96.173.

(ii) *Certification application.* The CAIR designated representative shall submit to the permitting authority a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the CAIR NO_X Annual Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the permitting authority.

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

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

(B) *Incomplete application notice*. If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the CAIR designated representative must submit the additional information required to complete the certification application. If the CAIR designated representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter). The owner or operator shall follow the procedures for loss of certification in paragraph (d)(3)(v) of this section for each monitoring system that is disapproved for initial certification.

(D) *Audit decertification.* The permitting authority or, for a CAIR NO_X opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, the Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 96.172(b).

(v) *Procedures for loss of certification.* If the permitting authority or the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(1) For a disapproved NO_X emission rate (*i.e.*, NO_X-diluent) system, the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(2) For a disapproved NO_X pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NO_X and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(3) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2

concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(4) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(5) For a disapproved excepted NO_X monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(B) The CAIR designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

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

(e) *Initial certification and recertification procedures for units using the low mass emission excepted methodology under § 75.19 of this chapter.* The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) *Certification/recertification procedures for alternative monitoring systems.* The CAIR designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 96.172 Out of control periods.

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

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 96.171 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority or, for a CAIR NO_X opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority or the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 96.171 for each disapproved monitoring system.

§ 96.173 Notifications.

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

§ 96.174 Recordkeeping and reporting.

(a) *General provisions.* The CAIR designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements under § 75.73 of this chapter, and the requirements of § 96.110(e)(1).

(b) *Monitoring Plans.* The owner or operator of a CAIR NO_X unit shall comply with requirements of § 75.73(c) and (e) of this chapter and, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart II of this part, §§ 96.183 and 96.184(a).

(c) *Certification Applications.* The CAIR designated representative shall submit an application to the permitting authority within 45 days after completing all initial certification or recertification tests required under § 96.171, including the information required under § 75.63 of this chapter.

(d) *Quarterly reports.* The CAIR designated representative shall submit quarterly reports, as follows:

(1) The CAIR designated representative shall report the NO_X mass emissions data and heat input data for the CAIR NO_X unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2007, the calendar quarter covering January 1, 2008 through March 31, 2008; or

(ii) For a unit that commences commercial operation on or after July 1, 2007, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 96.170(b), unless that quarter is the third or fourth quarter of 2007, in which case reporting shall commence in the quarter covering January 1, 2008 through March 31, 2008.

(2) The CAIR designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.73(f) of this chapter.

(3) For CAIR NO_X units that are also subject to an Acid Rain emissions limitation or the CAIR NO_X Ozone Season Trading Program or CAIR SO_2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NO_X mass emission data, heat input data, and other information required by this subpart.

(e) *Compliance certification.* The CAIR designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on NO_X emission controls and for all hours where NO_X data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO_X emissions.

§ 96.175 Petitions.

(a) Except as provided in paragraph (b)(2) of this section, the CAIR designated representative of a CAIR NO_X unit that is subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator, in consultation with the permitting authority.

(b)(1) The CAIR designated representative of a CAIR NO_X unit that is not subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by both the permitting authority and the Administrator.

(2) The CAIR designated representative of a CAIR NO_X unit that is subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to a requirement concerning any additional continuous emission monitoring system required under § 75.72 of this chapter. Application of an alternative to any such requirement is in accordance with this subpart only to the extent that the petition is approved in writing by both the permitting authority and the Administrator.

§ 96.176 Additional requirements to provide heat input data.

The owner or operator of a CAIR NO_X unit that monitors and reports NO_X mass emissions using a NO_X concentration system and a flow system shall also monitor and report heat input rate at the unit level using the procedures set forth in part 75 of this chapter.

Subpart II—CAIR NO_X Opt-in Units

§ 96.180 Applicability.

A CAIR NO_X opt-in unit must be a unit that:

(a) Is located in the State;

(b) Is not a CAIR NO_X unit under § 96.104 and is not covered by a retired unit exemption under § 96.105 that is in effect;

(c) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(d) Has or is required or qualified to have a title V operating permit or other federally enforceable permit; and

(e) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of subpart HH of this part.

§ 96.181 General.

(a) Except as otherwise provided in §§ 96.101 through 96.104, §§ 96.106 through 96.108, and subparts BB and CC and subparts FF through HH of this part, a CAIR NO_X opt-in unit shall be treated as a CAIR NO_X unit for purposes of applying such sections and subparts of this part.

(b) Solely for purposes of applying, as provided in this subpart, the requirements of subpart HH of this part to a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, such unit shall be treated as a CAIR NO_X unit before issuance of a CAIR opt-in permit for such unit.

§ 96.182 CAIR designated representative.

Any CAIR NO_X opt-in unit, and any unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, located at the same source as one or more CAIR NO_X units shall have the same CAIR designated representative and alternate CAIR designated representative as such CAIR NO_X units.

§ 96.183 Applying for CAIR opt-in permit.

(a) *Applying for initial CAIR opt-in permit.* The CAIR designated representative of a unit meeting the requirements for a CAIR NO_X opt-in unit in § 96.180 may apply for an initial CAIR opt-in permit at any time, except as provided under § 96.186(f) and (g), and, in order to apply, must submit the following:

(1) A complete CAIR permit application under § 96.122;

(2) A certification, in a format specified by the permitting authority, that the unit:

(i) Is not a CAIR NO_X unit under § 96.104 and is not covered by a retired unit exemption under § 96.105 that is in effect;

(ii) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(iii) Vents all of its emissions to a stack, and

(iv) Has documented heat input for more than 876 hours during the 6 months immediately preceding submission of the CAIR permit application under § 96.122;

(3) A monitoring plan in accordance with subpart HH of this part;

(4) A complete certificate of representation under § 96.113 consistent with § 96.182, if no CAIR designated representative has been previously designated for the source that includes the unit; and

(5) A statement, in a format specified by the permitting authority, whether the CAIR designated representative requests that the unit be allocated CAIR NO_X allowances under § 96.188(c) (subject to the conditions in §§ 96.184(h) and 96.186(g)).

(b) *Duty to reapply.* (1) The CAIR designated representative of a CAIR NO_X opt-in unit shall submit a complete CAIR permit application under § 96.122 to renew the CAIR opt-in unit permit in accordance with the permitting authority's regulations for title V operating permits, or the permitting authority's regulations for other federally enforceable permits if applicable, addressing permit renewal.

(2) Unless the permitting authority issues a notification of acceptance of withdrawal of the CAIR opt-in unit from the CAIR NO_X Annual Trading Program in accordance with § 96.186 or the unit becomes a CAIR NO_X unit under § 96.104, the CAIR NO_X opt-in unit shall remain subject to the requirements for a CAIR NO_X opt-in unit, even if the CAIR designated representative for the CAIR NO_X opt-in unit fails to submit a CAIR permit application that is required for renewal of the CAIR opt-in permit under paragraph (b)(1) of this section.

§ 96.184 Opt-in process.

The permitting authority will issue or deny a CAIR opt-in permit for a unit for which an initial application for a CAIR opt-in permit under § 96.183 is submitted in accordance with the following:

(a) *Interim review of monitoring plan.* The permitting authority and the Administrator will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a CAIR opt-in permit under § 96.183. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NO_X emissions rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with subpart HH of this part. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(b) *Monitoring and reporting.* (1)(i) If the permitting authority and the Administrator determine that the monitoring plan is sufficient under paragraph (a) of this section, the owner or operator shall monitor and report the NO_X emissions rate and the heat input of the unit and all other applicable parameters, in accordance with subpart HH of this part, starting on the date of certification of the appropriate monitoring systems under subpart HH of this part and continuing until a CAIR opt-in permit is denied under § 96.184(f) or, if a CAIR opt-in permit is issued, the date and time when the unit is withdrawn from the CAIR NO_X Annual Trading Program in accordance with § 96.186.

(ii) The monitoring and reporting under paragraph (b)(1)(i) of this section shall include the entire control period immediately before the date on which the unit enters the CAIR NO_X Annual Trading Program under § 96.184(g), during which period monitoring system availability must not be less than 90 percent under subpart HH of this part and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the NO_X emissions rate and the heat input of the unit are monitored and reported in accordance with subpart HH of this part for one or more control periods, in addition to the control period under paragraph (b)(1)(ii) of this section, during which control periods monitoring system availability is not less than 90 percent under subpart HH of this part and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the CAIR NO_X Annual Trading Program under § 96.184(g), such information shall be used as provided in paragraphs (c) and (d) of this section.

(c) *Baseline heat input.* The unit's baseline heat rate shall equal:

(1) If the unit's NO_X emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit's total heat input (in mmBtu) for the control period; or

(2) If the unit's NO_X emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, the average of the amounts of the unit's total heat input (in mmBtu) for the control period under paragraph (b)(1)(ii) of this section and for the control periods under paragraph (b)(2) of this section.

(d) *Baseline NO_X emission rate.* The unit's baseline NO_X emission rate shall equal:

(1) If the unit's NO_X emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit's NO_X emissions rate (in lb/mmBtu) for the control period;

(2) If the unit's NO_X emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit does not have add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emissions rate (in lb/mmBtu) for the control period under paragraph (b)(1)(ii) of this section and the control periods under paragraph (b)(2) of this section; or

(3) If the unit's NO_X emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit has add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emissions rate (in lb/mmBtu) for such control period during which the unit has add-on NO_X emission controls.

(e) *Issuance of CAIR opt-in permit.* After calculating the baseline heat input and the baseline NO_X emissions rate for the unit under paragraphs (c) and (d) of this section and if the permitting authority determines that the CAIR designated representative shows that the unit meets the requirements for a CAIR NO_X opt-in unit in § 96.180 and meets the elements certified in § 96.183(a)(2), the permitting authority will issue a CAIR opt-in permit. The permitting authority will provide a copy of the CAIR opt-in permit to the Administrator, who will then establish a compliance account for the source that includes the CAIR NO_X opt-in unit unless the source already has a compliance account.

(f) *Issuance of denial of CAIR opt-in permit.* Notwithstanding paragraphs (a) through (e) of this section, if at any time before issuance of a CAIR opt-in permit for the unit, the permitting authority determines that the CAIR designated representative fails to show that the unit meets the requirements for a CAIR NO_X opt-in unit in § 96.180 or meets the elements certified in § 96.183(a)(2), the permitting authority will issue a denial of a CAIR NO_X opt-in permit for the unit.

(g) *Date of entry into CAIR NO_X Annual Trading Program.* A unit for which an initial CAIR opt-in permit is issued by the permitting authority shall become a CAIR NO_X opt-in unit, and a CAIR NO_X unit, as of the later of January 1, 2009 or January 1 of the first control period during which such CAIR opt-in permit is issued.

(h) *Repowered CAIR NO_X opt-in unit.* (1) If CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR NO_X opt-in unit of CAIR NO_X allowances under § 96.188(c) and such unit is repowered after its date of entry into the CAIR NO_X Annual Trading Program under paragraph (g) of this section, the repowered unit shall be treated as a CAIR NO_X opt-in unit replacing the original CAIR NO_X opt-in unit, as of the date of start-up of the repowered unit's combustion chamber.

(2) Notwithstanding paragraphs (c) and (d) of this section, as of the date of start-up under paragraph (h)(1) of this section, the repowered unit shall be deemed to have the same date of commencement of operation, date of commencement of commercial operation, baseline heat input, and baseline NO_X emission rate as the original CAIR NO_X opt-in unit, and the original CAIR NO_X opt-in unit shall no longer be treated as a CAIR opt-in unit or a CAIR NO_X unit.

§ 96.185 CAIR opt-in permit contents.

(a) Each CAIR opt-in permit will contain:

(1) All elements required for a complete CAIR permit application under § 96.122;

(2) The certification in § 96.183(a)(2);

(3) The unit's baseline heat input under § 96.184(c);

(4) The unit's baseline NO_X emission rate under § 96.184(d);

(5) A statement whether the unit is to be allocated CAIR NO_X allowances under § 96.188(c) (subject to the

conditions in §§ 96.184(h) and 96.186(g));

(6) A statement that the unit may withdraw from the CAIR NO_X Annual Trading Program only in accordance with § 96.186; and

(7) A statement that the unit is subject to, and the owners and operators of the unit must comply with, the requirements of § 96.187.

(b) Each CAIR opt-in permit is deemed to incorporate automatically the definitions of terms under § 96.102 and, upon recordation by the Administrator under subpart FF or GG of this part or this subpart, every allocation, transfer, or deduction of CAIR NO_X allowances to or from the compliance account of the source that includes a CAIR NO_X opt-in unit covered by the CAIR opt-in permit.

§ 96.186 Withdrawal from CAIR NO_X Annual Trading Program.

Except as provided under paragraph (g) of this section, a CAIR NO_X opt-in unit may withdraw from the CAIR NO_X Annual Trading Program, but only if the permitting authority issues a notification to the CAIR designated representative of the CAIR NO_X opt-in unit of the acceptance of the withdrawal of the CAIR NO_X opt-in unit in accordance with paragraph (d) of this section.

(a) *Requesting withdrawal.* In order to withdraw a CAIR opt-in unit from the CAIR NO_X Annual Trading Program, the CAIR designated representative of the CAIR NO_X opt-in unit shall submit to the permitting authority a request to withdraw effective as of midnight of December 31 of a specified calendar year, which date must be at least 4 years after December 31 of the year of entry into the CAIR NO_X Annual Trading Program under § 96.184(g). The request must be submitted no later than 90 days before the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a CAIR NO_X opt-in unit covered by a request under paragraph (a) of this section may withdraw from the CAIR NO_X Annual Trading Program and the CAIR opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the CAIR NO_X opt-in unit must meet the requirement to hold CAIR NO_X allowances under § 96.106(c) and cannot have any excess emissions.

(2) After the requirement for withdrawal under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the CAIR NO_X opt-in unit CAIR NO_X allowances equal in number to and allocated for the same or a prior control period as any CAIR NO_X allowances allocated to the CAIR NO_X opt-in unit under § 96.188 for any control period for which the withdrawal is to be effective. If there are no remaining CAIR NO_X units at the source, the Administrator will close the compliance account, and the owners and operators of the CAIR NO_X opt-in unit may submit a CAIR NO_X allowance transfer for any remaining CAIR NO_X allowances to another CAIR NO_X Allowance Tracking System in accordance with subpart GG of this part.

(c) *Notification.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of CAIR NO_X allowances required), the permitting authority will issue a notification to the CAIR designated representative of the CAIR NO_X opt-in unit of the acceptance of the withdrawal of the CAIR NO_X opt-in unit as of midnight on December 31 of the calendar year for which the withdrawal was requested.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the permitting authority will issue a notification to the CAIR designated representative of the CAIR NO_X opt-in unit that the CAIR NO_X opt-in unit's request to withdraw is denied. Such CAIR NO_X opt-in unit shall continue to be a CAIR NO_X opt-in unit.

(d) *Permit amendment.* After the permitting authority issues a notification under paragraph (c)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the CAIR permit covering the CAIR NO_X opt-in unit to terminate the CAIR opt-in permit for such unit as of the effective date specified under paragraph (c)(1) of this section. The unit shall continue to be a CAIR NO_X opt-in unit until the effective date of the termination and shall comply with all requirements under the CAIR NO_X Annual Trading Program concerning any control periods for which the unit is a CAIR NO_X opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(e) *Reapplication upon failure to meet conditions of withdrawal.* If the permitting authority denies the CAIR NO_X opt-in unit's request to withdraw, the CAIR designated representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(f) *Ability to reapply to the CAIR NO_X Annual Trading Program.* Once a CAIR NO_X opt-in unit withdraws from the CAIR NO_X Annual Trading Program and its CAIR opt-in permit is terminated under this section, the CAIR designated representative may not submit another application for a CAIR opt-in permit under § 96.183 for such CAIR NO_X opt-in unit before the date that is 4 years after the date on which the withdrawal became effective. Such new application for a CAIR opt-in permit will be treated as an initial application for a CAIR opt-in permit under § 96.184.

(g) *Inability to withdraw.* Notwithstanding paragraphs (a) through (f) of this section, a CAIR NO_X opt-in unit shall not be eligible to withdraw from the CAIR NO_X Annual Trading Program if the CAIR designated representative of the CAIR NO_X opt-in unit requests, and the permitting authority issues a CAIR NO_X opt-in permit providing for, allocation to the CAIR NO_X opt-in unit of CAIR NO_X allowances under § 96.188(c).

§ 96.187 Change in regulatory status.

(a) *Notification.* If a CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104, then the CAIR designated representative shall notify in writing the permitting authority and the Administrator of such change in the CAIR NO_X opt-in unit's regulatory status, within 30 days of such change.

(b) *Permitting authority's and Administrator's actions.*

(1) If a CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104, the permitting authority will revise the CAIR NO_X opt-in unit's CAIR opt-in permit to meet the requirements of a CAIR permit under § 96.123 as of the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104.

(2)(i) The Administrator will deduct from the compliance account of the source that includes the CAIR NO_X opt-in unit that becomes a CAIR NO_X unit under § 96.104, CAIR NO_X allowances equal in number to and allocated for the same or a prior control period as:

(A) Any CAIR NO_X allowances allocated to the CAIR NO_X opt-in unit under § 96.188 for any control period after the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104; and

(B) If the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104 is not December 31, the CAIR NO_X allowances allocated to the CAIR NO_X opt-in unit under § 96.188 for the control period that includes the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under

§ 96.104, multiplied by the ratio of the number of days, in the control period, starting with the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104 divided by the total number of days in the control period and rounded to the nearest whole allowance as appropriate.

(ii) The CAIR designated representative shall ensure that the compliance account of the source that includes the CAIR NO_X unit that becomes a CAIR NO_X unit under § 96.104 contains the CAIR NO_X allowances necessary for completion of the deduction under paragraph (b)(2)(i) of this section.

(3)(i) For every control period after the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104, the CAIR NO_X opt-in unit will be treated, solely for purposes of CAIR NO_X allowance allocations under § 96.142, as a unit that commences operation on the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104 and will be allocated CAIR NO_X allowances under § 96.142.

(ii) Notwithstanding paragraph (b)(3)(i) of this section, if the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104 is not January 1, the following number of CAIR NO_X allowances will be allocated to the CAIR NO_X opt-in unit (as a CAIR NO_X unit) under § 96.142 for the control period that includes the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104:

(A) The number of CAIR NO_X allowances otherwise allocated to the CAIR NO_X opt-in unit (as a CAIR NO_X unit) under § 96.142 for the control period multiplied by;

(B) The ratio of the number of days, in the control period, starting with the date on which the CAIR NO_X opt-in unit becomes a CAIR NO_X unit under § 96.104, divided by the total number of days in the control period; and

(C) Rounded to the nearest whole allowance as appropriate.

§ 96.188 NO_X allowance allocations to CAIR NO_X opt-in units.

(a) *Timing requirements.* (1) When the CAIR opt-in permit is issued under § 96.184(e), the permitting authority will allocate CAIR NO_X allowances to the CAIR NO_X opt-in unit, and submit to the Administrator the allocation for the control period in which a CAIR NO_X opt-in unit enters the CAIR NO_X Annual Trading Program under § 96.184(g), in accordance with paragraph (b) or (c) of this section.

(2) By no later than October 31 of the control period in which a CAIR opt-in unit enters the CAIR NO_X Annual Trading Program under § 96.184(g) and October 31 of each year thereafter, the permitting authority will allocate CAIR NO_X allowances to the CAIR NO_X opt-in unit, and submit to the Administrator the allocation for the control period that includes such submission deadline and in which the unit is a CAIR NO_X opt-in unit, in accordance with paragraph (b) or (c) of this section.

(b) *Calculation of allocation.* For each control period for which a CAIR NO_X opt-in unit is to be allocated CAIR NO_X allowances, the permitting authority will allocate in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the CAIR NO_X allowance allocation will be the lesser of:

(i) The CAIR NO_X opt-in unit's baseline heat input determined under § 96.184(c); or

(ii) The CAIR NO_X opt-in unit's heat input, as determined in accordance with subpart HH of this part, for the immediately prior control period, except when the allocation is being calculated for the control period in which the CAIR NO_X opt-in unit enters the CAIR NO_X Annual Trading Program under § 96.184(g).

(2) The NO_X emission rate (in lb/mmBtu) used for calculating CAIR NO_X allowance allocations will be the lesser of:

(i) The CAIR NO_X opt-in unit's baseline NO_X emissions rate (in lb/mmBtu) determined under § 96.184(d) and multiplied by 70 percent; or

(ii) The most stringent State or Federal NO_X emissions limitation applicable to the CAIR NO_X opt-in unit at any time during the control period for which CAIR NO_X allowances are to be allocated.

(3) The permitting authority will allocate CAIR NO_X allowances to the CAIR NO_X opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the NO_X emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(c) Notwithstanding paragraph (b) of this section and if the CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR NO_X opt-in unit of CAIR NO_X allowances under this paragraph (subject to the conditions in §§ 96.184(h) and 96.186(g)), the permitting authority will allocate to the CAIR NO_X opt-in unit as follows:

(1) For each control period in 2009 through 2014 for which the CAIR NO_X opt-in unit is to be allocated CAIR NO_X allowances,

(i) The heat input (in mmBtu) used for calculating CAIR NO_X allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The NO_X emission rate (in lb/mmBtu) used for calculating CAIR NO_X allowance allocations will be the lesser of:

(A) The CAIR NO_X opt-in unit's baseline NO_X emissions rate (in lb/mmBtu) determined under § 96.184(d); or

(B) The most stringent State or Federal NO_X emissions limitation applicable to the CAIR NO_X opt-in unit at any time during the control period in which the CAIR NO_X opt-in unit enters the CAIR NO_X Annual Trading Program under § 96.184(g).

(iii) The permitting authority will allocate CAIR NO_X allowances to the CAIR NO_X opt-in unit in an amount equaling the heat input under paragraph (c)(1)(i) of this section, multiplied by the NO_X emission rate under paragraph (c)(1)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(2) For each control period in 2015 and thereafter for which the CAIR NO_X opt-in unit is to be allocated CAIR NO_X allowances,

(i) The heat input (in mmBtu) used for calculating the CAIR NO_X allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The NO_X emission rate (in lb/mmBtu) used for calculating the CAIR NO_X allowance allocation will be the lesser of:

(A) 0.15 lb/mmBtu;

(B) The CAIR NO_X opt-in unit's baseline NO_X emissions rate (in lb/mmBtu) determined under § 96.184(d); or

(C) The most stringent State or Federal NO_X emissions limitation applicable to the CAIR NO_X opt-in unit at any time during the control period for which CAIR NO_X allowances are to be allocated.

(iii) The permitting authority will allocate CAIR NO_X allowances to the CAIR NO_X opt-in unit in an amount equaling the heat input under paragraph (c)(2)(i) of this section, multiplied by the NO_X emission rate under paragraph (c)(2)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(d) *Recordation.* (1) The Administrator will record, in the compliance account of the source that includes the CAIR NO_X opt-in unit, the CAIR NO_X allowances allocated by the permitting authority to the CAIR NO_X opt-in unit under paragraph (a)(1) of this section.

(2) By December 1 of the control period in which a CAIR opt-in unit enters the CAIR NO_X Annual Trading Program under § 96.184(g) and December 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the CAIR NO_X opt-in unit, the CAIR NO_X allowances allocated by the permitting authority to the CAIR NO_X opt-in unit under paragraph (a)(2) of this section.

■ 3. Part 96 is amended by adding subparts AAA through CCC, adding and reserving subparts DDD and EEE and adding subparts FFF through III to read as follows:

Subpart AAA—CAIR SO_2 Trading Program General Provisions

Sec.
96.201 Purpose.
96.202 Definitions.
96.203 Measurements, abbreviations, and acronyms.
96.204 Applicability.
96.205 Retired unit exemption.
96.206 Standard requirements.
96.207 Computation of time.
96.208 Appeal procedures.

Subpart BBB—CAIR Designated Representative for CAIR SO_2 Sources

96.210 Authorization and responsibilities of CAIR designated representative.
96.211 Alternate CAIR designated representative.
96.212 Changing CAIR designated representative and alternate CAIR designated representative; changes in owners and operators.
96.213 Certificate of representation.
96.214 Objections concerning CAIR designated representative.

Subpart CCC—Permits

96.220 General CAIR SO_2 Trading Program permit requirements.
96.221 Submission of CAIR permit applications.
96.222 Information requirements for CAIR permit applications.
96.223 CAIR permit contents and term.
96.224 CAIR permit revisions.

Subpart DDD—[Reserved]

Subpart EEE—[Reserved]

Subpart FFF—CAIR SO_2 Allowance Tracking System

96.250 [Reserved]
96.251 Establishment of accounts.
96.252 Responsibilities of CAIR authorized account representative.
96.253 Recordation of CAIR SO_2 allowances.
96.254 Compliance with CAIR SO_2 emissions limitation.
96.255 Banking.
96.256 Account error.
96.257 Closing of general accounts.

Subpart GGG—CAIR SO_2 Allowance Transfers

96.260 Submission of CAIR SO_2 allowance transfers.
96.261 EPA recordation.
96.262 Notification.

Subpart HHH—Monitoring and Reporting

96.270 General requirements.
96.271 Initial certification and recertification procedures.
96.272 Out of control periods.
96.273 Notifications.
96.274 Recordkeeping and reporting.
96.275 Petitions.
96.276 Additional requirements to provide heat input data.

Subpart III—CAIR SO_2 Opt-in Units

96.280 Applicability.
96.281 General.
96.282 CAIR designated representative.
96.283 Applying for CAIR opt-in permit.
96.284 Opt-in process.
96.285 CAIR opt-in permit contents.
96.286 Withdrawal from CAIR SO_2 Trading Program.
96.287 Change in regulatory status.
96.288 SO_2 allowance allocations to CAIR SO_2 opt-in units.

Subpart AAA—CAIR SO_2 Trading Program General Provisions

§ 96.201 Purpose.

This subpart and subparts BBB through III establish the model rule comprising general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the State Clean Air Interstate Rule (CAIR) SO_2 Trading Program, under section 110 of the Clean Air Act and § 51.124 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide. The owner or operator of a unit or a source shall comply with the requirements of this subpart and subparts BBB through III as a matter of federal law only if the State with jurisdiction over the unit and the source incorporates by reference such subparts or otherwise adopts the requirements of such subparts in accordance with § 51.124(o)(1) or (2) of this chapter, the State submits to the Administrator one or more revisions of the State implementation plan that include such adoption, and the Administrator approves such revisions. If the State adopts the requirements of such subparts in accordance with § 51.124(o)(1) or (2) of this chapter, then the State authorizes the Administrator to assist the State in implementing the CAIR SO_2 Trading Program by carrying out the functions set forth for the Administrator in such subparts.

§ 96.202 Definitions.

The terms used in this subpart and subparts BBB through III shall have the meanings set forth in this section as follows:

Account number means the identification number given by the Administrator to each CAIR SO_2 Allowance Tracking System account.

Acid Rain emissions limitation means a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program.

Acid Rain Program means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

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

Allocate or *allocation* means, with regard to CAIR SO_2 allowances issued under the Acid Rain Program, the determination by the Administrator of the amount of such CAIR SO_2 allowances to be initially credited to a CAIR SO_2 unit and, with regard to CAIR SO_2 allowances issued under § 96.288, the determination by the permitting authority of the amount of such CAIR SO_2 allowances to be initially credited to a CAIR SO_2 unit.

Allowance transfer deadline means, for a control period, midnight of March 1, if it is a business day, or, if March 1 is not a business day, midnight of the first business day thereafter immediately following the control period and is the deadline by which a CAIR SO_2 allowance transfer must be submitted for recordation in a CAIR SO_2 source's compliance account in order to be used to meet the source's CAIR SO_2 emissions limitation for such control period in accordance with § 96.254.

Alternate CAIR designated representative means, for a CAIR SO_2 source and each CAIR SO_2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source in accordance with subparts BBB and III of this part, to act on behalf of the CAIR designated representative in matters pertaining to the CAIR SO_2 Trading Program. If the CAIR SO_2 source is also a CAIR NO_X source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR NO_X Annual Trading Program. If the CAIR SO_2 source is also a CAIR NO_X Ozone Season source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR NO_X Ozone Season Trading Program. If the CAIR SO_2 source is also subject to the Acid Rain Program, then this natural person shall be the same person as the alternate designated representative under the Acid Rain Program.

Automated data acquisition and handling system or *DAHS* means that component of the continuous emission monitoring system, or other emissions monitoring system approved for use under subpart HHH of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart HHH of this part.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

CAIR authorized account representative means, with regard to a general account, a responsible natural person who is authorized, in accordance with subparts BBB and III of this part, to transfer and otherwise dispose of CAIR SO_2 allowances held in the general account and, with regard to a compliance account, the CAIR designated representative of the source.

CAIR designated representative means, for a CAIR SO_2 source and each CAIR SO_2 unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BBB and III of this part, to represent and legally bind each owner and operator in matters pertaining to the CAIR SO_2 Trading Program. If the CAIR SO_2 source is also a CAIR NO_X source, then this natural person shall be the same person as the CAIR designated representative under the CAIR NO_X Annual Trading Program. If the CAIR SO_2 source is also a CAIR NO_X Ozone Season source, then this natural person shall be the same person as the CAIR designated representative under the CAIR NO_X Ozone Season Trading Program. If the CAIR SO_2 source is also subject to the Acid Rain Program, then this natural person shall be the same person as the designated representative under the Acid Rain Program.

CAIR NO_X Annual Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AA through II of this part and § 51.123 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

CAIR NO_X Ozone Season source means a source that includes one or more CAIR NO_X Ozone Season units.

CAIR NO_X Ozone Season Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAAA through IIII of this part and § 51.123 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

CAIR NO_X Ozone Season unit means a unit that is subject to the CAIR NO_X Ozone Season Trading Program under § 96.304 and a CAIR NO_X Ozone Season opt-in unit under subpart IIII of this part.

CAIR NO_X source means a source that includes one or more CAIR NO_X units.

CAIR NO_X unit means a unit that is subject to the CAIR NO_X Annual Trading Program under § 96.104 and a CAIR NO_X opt-in unit under subpart II of this part.

CAIR permit means the legally binding and federally enforceable written document, or portion of such document, issued by the permitting authority under subpart CCC of this part, including any permit revisions, specifying the CAIR SO_2 Trading Program requirements applicable to a CAIR SO_2 source, to each CAIR SO_2 unit at the source, and to the owners and operators and the CAIR designated representative of the source and each such unit.

CAIR SO_2 allowance means a limited authorization issued by the Administrator under the Acid Rain Program, or by a permitting authority under § 96.288, to emit sulfur dioxide during the control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CAIR SO_2 Trading Program as follows:

(1) For one CAIR SO_2 allowance allocated for a control period in a year before 2010, one ton of sulfur dioxide, except as provided in § 96.254(b);

(2) For one CAIR SO_2 allowance allocated for a control period in 2010 through 2014, 0.50 ton of sulfur dioxide, except as provided in § 96.254(b); and

(3) For one CAIR SO_2 allowance allocated for a control period in 2015 or later, 0.35 ton of sulfur dioxide, except as provided in § 96.254(b).

An authorization to emit sulfur dioxide that is not issued under the Acid Rain Program or under the provisions of a State implementation plan that is approved under § 51.124(o)(1) or (2) of this chapter shall not be a CAIR SO_2 allowance.

CAIR SO_2 allowance deduction or *deduct CAIR SO_2 allowances* means the permanent withdrawal of CAIR SO_2 allowances by the Administrator from a compliance account in order to account for a specified number of tons of total sulfur dioxide emissions from all CAIR SO_2 units at a CAIR SO_2 source for a control period, determined in accordance with subpart HHH of this part, or to account for excess emissions.

CAIR SO_2 Allowance Tracking System means the system by which the Administrator records allocations, deductions, and transfers of CAIR SO_2 allowances under the CAIR SO_2 Trading Program. This is the same system as the Allowance Tracking System under § 72.2 of this chapter by which the Administrator records allocations, deduction, and transfers of Acid Rain SO_2 allowances under the Acid Rain Program.

CAIR SO_2 Allowance Tracking System account means an account in the CAIR SO_2 Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of CAIR SO_2 allowances. Such allowances will be allocated, held, deducted, or transferred only as whole allowances.

CAIR SO_2 allowances held or *hold CAIR SO_2 allowances* means the CAIR SO_2 allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts FFF, GGG, and III of this part or part 73 of this chapter, in a CAIR SO_2 Allowance Tracking System account.

CAIR SO_2 emissions limitation means, for a CAIR SO_2 source, the tonnage equivalent of the CAIR SO_2 allowances available for deduction for the source under § 96.254(a) and (b) for a control period.

CAIR SO_2 source means a source that includes one or more CAIR SO_2 units.

CAIR SO_2 Trading Program means a multi-state sulfur dioxide air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAA through III of this part and § 51.124 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

CAIR SO_2 unit means a unit that is subject to the CAIR SO_2 Trading Program under § 96.204 and, except for purposes of § 96.205, a CAIR SO_2 opt-in unit under subpart III of this part.

Clean Air Act or *CAA* means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means combusting any amount of coal or coal-derived fuel, alone, or in combination with any amount of any other fuel.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity—

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

Combustion turbine means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated heat recovery steam generator and steam turbine.

Commence commercial operation means, with regard to a unit serving a generator:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 96.205.

(i) For a unit that is a CAIR SO_2 unit under § 96.204 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit that is a CAIR SO_2 unit under § 96.204 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 96.205, for a unit that is not a CAIR SO_2 unit under § 96.204 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and is not a unit under paragraph (3) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a CAIR SO_2 unit under § 96.204.

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(3) Notwithstanding paragraph (1) of this definition and except as provided in § 96.284(h) or § 96.287(b)(3), for a CAIR SO_2 opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the unit's date for commencement of commercial operation shall be the date on which the owner or operator is required to start monitoring and reporting the SO_2 emissions rate and the heat input of the unit under § 96.284(b)(1)(i).

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (3) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (3) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(4) Notwithstanding paragraphs (1) through (3) of this definition, for a unit not serving a generator producing electricity for sale, the unit's date of commencement of operation shall also be the unit's date of commencement of commercial operation.

Commence operation means:

(1) To have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber, except as provided in § 96.205.

(i) For a unit that is a CAIR SO_2 unit under § 96.204 on the date the unit commences operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit that is a CAIR SO_2 unit under § 96.204 on the date the unit commences operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 96.205, for a unit that is not a CAIR SO_2 unit under § 96.204 on the date the unit commences operation as defined in paragraph (1) of this definition and is not a unit under paragraph (3) of this definition, the unit's date for commencement of operation shall be the date on which the unit becomes a CAIR SO_2 unit under § 96.204.

(i) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1),(2), or (3) of this definition as appropriate.

(3) Notwithstanding paragraph (1) of this definition and except as provided in § 96.284(h) or § 96.287(b)(3), for a CAIR SO_2 opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the unit's date for commencement of operation shall be the date on which the owner or operator is required to start monitoring and reporting the SO_2 emissions rate and the heat input of the unit under § 96.284(b)(1)(i).

(i) For a unit with a date for commencement of operation as defined in paragraph (3) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit with a date for commencement of operation as defined in paragraph (3) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means a CAIR SO_2 Allowance Tracking System account, established by the Administrator for a CAIR SO_2 source subject to an Acid Rain emissions limitations under § 73.31(a) or (b) of this chapter or for any other CAIR SO_2 source under subpart FFF or III of this part, in which any CAIR SO_2 allowance allocations for the CAIR SO_2 units at the source are initially recorded and in which are held any CAIR SO_2 allowances available for use for a control period in order to meet the source's CAIR SO_2 emissions limitation in accordance with § 96.254.

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

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A sulfur dioxide monitoring system, consisting of a SO_2 pollutant concentration monitor and an automated data acquisition handling system and providing a permanent, continuous record of SO_2 emissions, in parts per million (ppm);

(3) A moisture monitoring system, as defined in § 75.11(b)(2) of this chapter and providing a permanent, continuous record of the stack gas moisture content, in percent H_2O;

(4) A carbon dioxide monitoring system, consisting of a CO_2 pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(5) An oxygen monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2 in percent O_2.

Control period means the period beginning January 1 of a calendar year and ending on December 31 of the same year, inclusive.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the CAIR designated representative and as determined by the Administrator in accordance with subpart HHH of this part.

Excess emissions means any ton, or portion of a ton, of sulfur dioxide emitted by the CAIR SO_2 units at a CAIR SO_2 source during a control period that exceeds the CAIR SO_2 emissions limitation for the source, provided that any portion of a ton of excess emissions shall be treated as one ton of excess emissions.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

General account means a CAIR SO_2 Allowance Tracking System account, established under subpart FFF of this part, that is not a compliance account.

Generator means a device that produces electricity.

Heat input means, with regard to a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/mmBtu and multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the CAIR designated representative and determined by the Administrator in accordance with subpart HHH of this part and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means, starting from the initial installation of a unit, the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as specified by the manufacturer of the unit, or, starting from the completion of any subsequent physical change in the unit resulting in a decrease in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis, such decreased maximum amount as specified by the person conducting the physical change.

Monitoring system means any monitoring system that meets the requirements of subpart HHH of this part, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Most stringent State or Federal SO_2 emissions limitation means, with regard to a unit, the lowest SO_2 emissions limitation (in terms of lb/mmBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as specified by the person conducting the physical change.

Operator means any person who operates, controls, or supervises a CAIR SO_2 unit or a CAIR SO_2 source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means any of the following persons:

(1) With regard to a CAIR SO_2 source or a CAIR SO_2 unit at a source, respectively:

(i) Any holder of any portion of the legal or equitable title in a CAIR SO_2 unit at the source or the CAIR SO_2 unit;

(ii) Any holder of a leasehold interest in a CAIR SO_2 unit at the source or the CAIR SO_2 unit; or

(iii) Any purchaser of power from a CAIR SO_2 unit at the source or the CAIR SO_2 unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such CAIR SO_2 unit; or

(2) With regard to any general account, any person who has an ownership interest with respect to the CAIR SO_2 allowances held in the general account and who is subject to the binding agreement for the CAIR authorized account representative to represent the person's ownership interest with respect to CAIR SO_2 allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the CAIR SO_2 Trading Program in accordance with subpart CCC of this part or, if no such agency has been so authorized, the Administrator.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or *recorded* means, with regard to CAIR SO_2 allowances, the movement of CAIR SO_2 allowances by the Administrator into or between CAIR SO_2 Allowance Tracking System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Repowered means, with regard to a unit, replacement of a coal-fired boiler with one of the following coal-fired technologies at the same source as the coal-fired boiler:

(1) Atmospheric or pressurized fluidized bed combustion;

(2) Integrated gasification combined cycle;

(3) Magnetohydrodynamics;

(4) Direct and indirect coal-fired turbines;

(5) Integrated gasification fuel cells; or

(6) As determined by the Administrator in consultation with the Secretary of Energy, a derivative of one or more of the technologies under paragraphs (1) through (5) of this definition and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

Serial number means, for a CAIR SO_2 allowance, the unique identification number assigned to each CAIR SO_2 allowance by the Administrator.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. For purposes of section 502(c) of the Clean Air Act, a "source," including a "source" with multiple units, shall be considered a single "facility."

State means one of the States or the District of Columbia that adopts the CAIR SO_2 Trading Program pursuant to § 51.124 (o)(1) or (2) of this chapter.

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

(1) In person;

(2) By United States Postal Service; or

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

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

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

Ton means 2,000 pounds. For the purpose of determining compliance with the CAIR SO_2 emissions limitation, total tons of sulfur dioxide emissions for a control period shall be calculated as the sum of all recorded hourly emissions (or the mass equivalent of the recorded hourly emission rates) in accordance with subpart HHH of this part, but with any remaining fraction of a ton equal to or greater than 0.50 tons deemed to equal one ton and any remaining fraction of a ton less than 0.50 tons deemed to equal zero tons.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself.

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

Unit means a stationary, fossil-fuel-fired boiler or combustion turbine or other stationary, fossil-fuel-fired combustion device.

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

Unit operating hour or *hour of unit operation* means an hour in which a unit combusts any fuel.

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heat application (*e.g.*, space heating or domestic hot water heating); or

(3) Used in a space cooling application (*i.e.*, thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 96.203 Measurements, abbreviations, and acronyms.

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

Btu-British thermal unit.
CO_2—carbon dioxide.
NO_X—nitrogen oxides.
hr—hour.
kW—kilowatt electrical.
kWh—kilowatt hour.
mmBtu—million Btu.
MWe—megawatt electrical.
MWh—megawatt hour.
O_2—oxygen.
ppm—parts per million.
lb—pound.
scfh—standard cubic feet per hour.
SO_2—sulfur dioxide.
H_2O—water.
yr—year.

§ 96.204 Applicability.

The following units in a State shall be CAIR SO_2 units, and any source that includes one or more such units shall be a CAIR SO_2 source, subject to the requirements of this subpart and subparts BBB through HHH of this part:

(a) Except as provided in paragraph (b) of this section, a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the start-up of the unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this section starting on the day on which the unit first no longer qualifies as a cogeneration unit.

§ 96.205 Retired unit exemption.

(a)(1) Any CAIR SO_2 unit that is permanently retired and is not a CAIR SO_2 opt-in unit under subpart III of this part shall be exempt from the CAIR SO_2 Trading Program, except for the provisions of this section, § 96.202, § 96.203, § 96.204, § 96.206(c)(4) through (8), § 96.207, and subparts FFF and GGG of this part.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the CAIR SO_2 unit is permanently retired. Within 30 days of the unit's permanent retirement, the CAIR designated representative shall submit a statement to the permitting authority otherwise responsible for administering any CAIR permit for the unit and shall submit a copy of the statement to the Administrator. The statement shall state, in a format prescribed by the permitting authority, that the unit was permanently retired on a specific date and will comply with the requirements of paragraph (b) of this section.

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

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any sulfur dioxide, starting on the date that the exemption takes effect.

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

(3) The owners and operators and, to the extent applicable, the CAIR designated representative of a unit exempt under paragraph (a) of this section shall comply with the requirements of the CAIR SO_2 Trading Program concerning all periods for which the exemption is not in effect, even if such requirements arise, or must be complied with, after the exemption takes effect.

(4) A unit exempt under paragraph (a) of this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the CAIR designated representative of the source submits a complete CAIR permit application under § 96.222 for the unit not less than 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2010 or the date on which the unit resumes operation.

(5) On the earlier of the following dates, a unit exempt under paragraph (a) of this section shall lose its exemption:

(i) The date on which the CAIR designated representative submits a CAIR permit application for the unit under paragraph (b)(4) of this section;

(ii) The date on which the CAIR designated representative is required under paragraph (b)(4) of this section to submit a CAIR permit application for the unit; or

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

(6) For the purpose of applying monitoring, reporting, and recordkeeping requirements under subpart HHH of this part, a unit that loses its exemption under paragraph (a) of this section shall be treated as a unit that commences operation and commercial operation on the first date on which the unit resumes operation.

§ 96.206 Standard requirements.

(a) *Permit requirements.* (1) The CAIR designated representative of each CAIR SO_2 source required to have a title V operating permit and each CAIR SO_2 unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under § 96.222 in accordance with the deadlines specified in § 96.221(a) and (b); and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR SO_2 source required to have a title V operating permit and each CAIR SO_2 unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart III of this part, the owners and operators of a CAIR SO_2 source that is not otherwise required to have a title V operating permit and each CAIR SO_2 unit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CCC of this part for such CAIR SO_2 source and such CAIR SO_2 unit.

(b) *Monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the CAIR designated representative, of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHH of this part.

(2) The emissions measurements recorded and reported in accordance with subpart HHH of this part shall be used to determine compliance by each CAIR SO_2 source with the CAIR SO_2 emissions limitation under paragraph (c) of this section.

(c) *Sulfur dioxide emission requirements.* (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, a tonnage equivalent in CAIR SO_2 allowances available for compliance deductions for the control period, as determined in accordance with § 96.254(a) and (b), not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance with subpart HHH of this part.

(2) A CAIR SO_2 unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later of January 1, 2010 or the deadline for meeting the unit's monitor certification requirements under § 96.270(b)(1),(2), or (5).

(3) A CAIR SO_2 allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.

(4) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 Allowance Tracking System accounts in accordance with subparts FFF and GGG of this part.

(5) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 Trading Program. No provision of the CAIR SO_2 Trading Program, the CAIR permit application, the CAIR permit, or an exemption under § 96.205 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR SO_2 allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart FFF, GGG, or III of this part, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 unit's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR SO_2 unit.

(d) *Excess emissions requirements*—(1) If a CAIR SO_2 source emits sulfur dioxide during any control period in excess of the CAIR SO_2 emissions limitation, then:

(i) The owners and operators of the source and each CAIR SO_2 unit at the source shall surrender the CAIR SO_2 allowances required for deduction under § 96.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(ii) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(2) [Reserved]

(e) *Recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under § 96.213 for the CAIR designated representative for the source and each CAIR SO_2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under § 96.213 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subpart HHH of this part, provided that to the extent that subpart HHH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR SO_2 Trading Program.

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR SO_2 Trading Program or to demonstrate compliance with the requirements of the CAIR SO_2 Trading Program.

(2) The CAIR designated representative of a CAIR SO_2 source and each CAIR SO_2 unit at the source shall submit the reports required under the CAIR SO_2 Trading Program, including those under subpart HHH of this part.

(f) *Liability.* (1) Each CAIR SO_2 source and each CAIR SO_2 unit shall meet the requirements of the CAIR SO_2 Trading Program.

(2) Any provision of the CAIR SO_2 Trading Program that applies to a CAIR SO_2 source or the CAIR designated representative of a CAIR SO_2 source shall also apply to the owners and operators of such source and of the CAIR SO_2 units at the source.

(3) Any provision of the CAIR SO_2 Trading Program that applies to a CAIR SO_2 unit or the CAIR designated representative of a CAIR SO_2 unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the CAIR SO_2 Trading Program, a CAIR permit application, a CAIR permit, or an exemption under § 96.205 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR SO_2 source or CAIR SO_2 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 96.207 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CAIR SO_2 Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CAIR SO_2 Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CAIR SO_2 Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 96.208 Appeal procedures.

The appeal procedures for decisions of the Administrator under the CAIR SO_2 Trading Program are set forth in part 78 of this chapter.

Subpart BBB—CAIR Designated Representative for CAIR SO_2 Sources

§ 96.210 Authorization and responsibilities of CAIR designated representative.

(a) Except as provided under § 96.211, each CAIR SO_2 source, including all CAIR SO_2 units at the source, shall have one and only one CAIR designated representative, with regard to all matters under the CAIR SO_2 Trading Program concerning the source or any CAIR SO_2 unit at the source.

(b) The CAIR designated representative of the CAIR SO_2 source shall be selected by an agreement binding on the owners and operators of the source and all CAIR SO_2 units at the source and shall act in accordance with the certification statement in § 96.213(a)(4)(iv).

(c) Upon receipt by the Administrator of a complete certificate of representation under § 96.213, the CAIR designated representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the CAIR SO_2 source represented and each CAIR SO_2 unit at the source in all matters pertaining to the CAIR SO_2 Trading Program, notwithstanding any agreement between the CAIR designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CAIR designated representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No CAIR permit will be issued, no emissions data reports will be accepted, and no CAIR SO_2 Allowance Tracking System account will be established for a CAIR SO_2 unit at a source, until the Administrator has received a complete certificate of representation under § 96.213 for a CAIR designated representative of the source and the CAIR SO_2 units at the source.

(e)(1) Each submission under the CAIR SO_2 Trading Program shall be submitted, signed, and certified by the CAIR designated representative for each CAIR SO_2 source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CAIR designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) The permitting authority and the Administrator will accept or act on a submission made on behalf of owner or operators of a CAIR SO_2 source or a CAIR SO_2 unit only if the submission has been made, signed, and certified in accordance with paragraph (e)(1) of this section.

§ 96.211 Alternate CAIR designated representative.

(a) A certificate of representation under § 96.213 may designate one and only one alternate CAIR designated representative, who may act on behalf of the CAIR designated representative. The agreement by which the alternate CAIR designated representative is selected shall include a procedure for authorizing the alternate CAIR designated representative to act in lieu of the CAIR designated representative.

(b) Upon receipt by the Administrator of a complete certificate of representation under § 96.213, any representation, action, inaction, or submission by the alternate CAIR designated representative shall be deemed to be a representation, action, inaction, or submission by the CAIR designated representative.

(c) Except in this section and §§ 96.202, 96.210(a) and (d), 96.212, 96.213, 96.251, and 96.282, whenever the term ''CAIR designated representative'' is used in subparts AAA through III of this part, the term shall be construed to include the CAIR designated representative or any alternate CAIR designated representative.

§ 96.212 Changing CAIR designated representative and alternate CAIR designated representative; changes in owners and operators.

(a) *Changing CAIR designated representative.* The CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 96.213. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new CAIR designated representative and the owners and operators of the CAIR SO_2 source and the CAIR SO_2 units at the source.

(b) *Changing alternate CAIR designated representative.* The alternate CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 96.213. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate CAIR designated representative and the owners and operators of the CAIR SO_2 source and the CAIR SO_2 units at the source.

(c) *Changes in owners and operators.* (1) In the event a new owner or operator of a CAIR SO_2 source or a CAIR SO_2 unit is not included in the list of owners and operators in the certificate of representation under § 96.213, such new owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the CAIR designated representative and any alternate CAIR designated representative of the source or unit, and the decisions and orders of the permitting authority, the Administrator, or a court, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a CAIR SO_2 source or a CAIR SO_2 unit, including the addition of a new owner or operator, the CAIR designated representative or any alternate CAIR designated representative shall submit a revision to the certificate of representation under § 96.213 amending the list of owners and operators to include the change.

§ 96.213 Certificate of representation.

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

(1) Identification of the CAIR SO_2 source, and each CAIR SO_2 unit at the source, for which the certificate of representation is submitted.

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

(3) A list of the owners and operators of the CAIR SO_2 source and of each CAIR SO_2 unit at the source.

(4) The following certification statements by the CAIR designated representative and any alternate CAIR designated representative—

(i) ''I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CAIR SO_2 unit at the source.''

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR SO_2 Trading Program on behalf of the owners and operators of the source and of each CAIR SO_2 unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.''

(iii) ''I certify that the owners and operators of the source and of each CAIR SO_2 unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.''

(iv) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR SO_2 unit, or where a customer purchases power from a CAIR SO_2 unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'CAIR designated representative' or 'alternate CAIR designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CAIR SO_2 unit at the source; and CAIR SO_2 allowances and proceeds of transactions involving CAIR SO_2 allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR SO_2 allowances by contract, CAIR SO_2 allowances and proceeds of transactions involving CAIR SO_2 allowances will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the CAIR designated representative and any alternate CAIR designated representative and the dates signed.

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

§ 96.214 Objections concerning CAIR designated representative.

(a) Once a complete certificate of representation under § 96.213 has been submitted and received, the permitting authority and the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 96.213 is received by the Administrator.

(b) Except as provided in § 96.212(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the CAIR designated representative shall affect any representation, action, inaction, or submission of the CAIR designated representative or the finality of any decision or order by the permitting authority or the Administrator under the CAIR SO_2 Trading Program.

(c) Neither the permitting authority nor the Administrator will adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any CAIR designated representative, including private legal disputes concerning the proceeds of CAIR SO_2 allowance transfers.

Subpart CCC—Permits

§ 96.220 General CAIR SO_2 Trading Program permit requirements.

(a) For each CAIR SO_2 source required to have a title V operating permit or required, under subpart III of this part, to have a title V operating permit or other federally enforceable permit, such permit shall include a CAIR permit administered by the permitting authority for the title V operating permit or the federally enforceable permit as applicable. The CAIR portion of the title V permit or other federally enforceable permit as applicable shall be administered in accordance with the permitting authority's title V operating permits regulations promulgated under part 70 or 71 of this chapter or the permitting authority's regulations for other federally enforceable permits as applicable, except as provided otherwise by this subpart and subpart III of this part.

(b) Each CAIR permit shall contain, with regard to the CAIR SO_2 source and the CAIR SO_2 units at the source, all applicable CAIR SO_2 Trading Program, CAIR NO_X Annual Trading Program, and CAIR NO_X Ozone Season Trading Program requirements and shall be a complete and separable portion of the title V operating permit or other federally enforceable permit under paragraph (a) of this section.

§ 96.221 Submission of CAIR permit applications.

(a) *Duty to apply.* The CAIR designated representative of any CAIR SO_2 source required to have a title V operating permit shall submit to the permitting authority a complete CAIR permit application under § 96.222 for the source covering each CAIR SO_2 unit at the source at least 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2010 or the date on which the CAIR SO_2 unit commences operation.

(b) *Duty to Reapply.* For a CAIR SO_2 source required to have a title V operating permit, the CAIR designated representative shall submit a complete CAIR permit application under § 96.222 for the source covering each CAIR SO_2 unit at the source to renew the CAIR permit in accordance with the permitting authority's title V operating permits regulations addressing permit renewal.

§ 96.222 Information requirements for CAIR permit applications.

A complete CAIR permit application shall include the following elements concerning the CAIR SO_2 source for which the application is submitted, in a format prescribed by the permitting authority:

(a) Identification of the CAIR SO_2 source;

(b) Identification of each CAIR SO_2 unit at the CAIR SO_2 source; and

(c) The standard requirements under § 96.206.

§ 96.223 CAIR permit contents and term.

(a) Each CAIR permit will contain, in a format prescribed by the permitting authority, all elements required for a complete CAIR permit application under § 96.222.

(b) Each CAIR permit is deemed to incorporate automatically the definitions of terms under § 96.202 and, upon recordation by the Administrator under subpart FFF, GGG, or III of this part, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from the compliance account of the CAIR SO_2 source covered by the permit.

(c) The term of the CAIR permit will be set by the permitting authority, as necessary to facilitate coordination of the renewal of the CAIR permit with issuance, revision, or renewal of the CAIR SO_2 source's title V operating permit or other federally enforceable permit as applicable.

§ 96.224 CAIR permit revisions.

Except as provided in § 96.223(b), the permitting authority will revise the CAIR permit, as necessary, in accordance with the permitting authority's title V operating permits regulations or the permitting authority's regulations for other federally enforceable permits as applicable addressing permit revisions.

Subpart DDD—[Reserved]

Subpart EEE—[Reserved]

Subpart FFF—CAIR SO_2 Allowance Tracking System

§ 96.250 [Reserved]

§ 96.251 Establishment of accounts.

(a) *Compliance accounts.* Except as provided in § 96.284(e), upon receipt of a complete certificate of representation under § 96.213, the Administrator will establish a compliance account for the CAIR SO_2 source for which the certificate of representation was submitted, unless the source already has a compliance account.

(b) *General accounts*—(1) *Application for general account.*

(i) Any person may apply to open a general account for the purpose of holding and transferring CAIR SO_2 allowances. An application for a general account may designate one and only one CAIR authorized account representative and one and only one alternate CAIR authorized account representative who may act on behalf of the CAIR authorized account representative. The agreement by which the alternate CAIR authorized account representative is selected shall include a procedure for authorizing the alternate CAIR authorized account representative to act in lieu of the CAIR authorized account representative.

(ii) A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR authorized account representative and any alternate CAIR authorized account representative;

(B) Organization name and type of organization, if applicable;

(C) A list of all persons subject to a binding agreement for the CAIR authorized account representative and any alternate CAIR authorized account representative to represent their ownership interest with respect to the CAIR SO_2 allowances held in the general account;

(D) The following certification statement by the CAIR authorized account representative and any alternate CAIR authorized account representative: ''I certify that I was selected as the CAIR authorized account representative or the alternate CAIR authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CAIR SO_2 allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR SO_2 Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account.''

(E) The signature of the CAIR authorized account representative and any alternate CAIR authorized account representative and the dates signed.

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

(2) *Authorization of CAIR authorized account representative.*

(i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(A) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(B) The CAIR authorized account representative and any alternate CAIR authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CAIR SO_2 allowances held in the general account in all matters pertaining to the CAIR SO_2 Trading Program, notwithstanding any agreement between the CAIR authorized account representative or any alternate CAIR authorized account representative and such person. Any such person shall be bound by any order or decision issued to the CAIR authorized account representative or any alternate CAIR authorized account representative by the Administrator or a court regarding the general account.

(C) Any representation, action, inaction, or submission by any alternate CAIR authorized account representative shall be deemed to be a representation, action, inaction, or submission by the CAIR authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the CAIR authorized account representative or any alternate CAIR authorized account representative for the persons having an ownership interest with respect to CAIR SO_2 allowances held in the general account. Each such submission shall include the following certification statement by the CAIR authorized account representative or any alternate CAIR authorized account representative: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CAIR SO_2 allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iii) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(ii) of this section.

(3) *Changing CAIR authorized account representative and alternate CAIR authorized account representative; changes in persons with ownership interest.*

(i) The CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR SO_2 allowances in the general account.

(ii) The alternate CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR SO_2 allowances in the general account.

(iii)(A) In the event a new person having an ownership interest with respect to CAIR SO_2 allowances in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the CAIR authorized account representative and any alternate CAIR authorized account representative of the account, and the decisions and orders of the Administrator or a court, as if the new person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to CAIR SO_2 allowances in the general account, including the addition of persons, the CAIR authorized account representative or any alternate CAIR authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CAIR SO_2 allowances in the general account to include the change.

(4) *Objections concerning CAIR authorized account representative.*

(i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative for a general account shall affect any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative or the finality of any decision or order by the Administrator under the CAIR SO_2 Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative for a general account, including private legal disputes concerning the proceeds of CAIR SO_2 allowance transfers.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

§ 96.252 Responsibilities of CAIR authorized account representative.

Following the establishment of a CAIR SO_2 Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CAIR SO_2 allowances in the account, shall be made only by the CAIR authorized account representative for the account.

§ 96.253 Recordation of CAIR SO_2 allowances.

(a)(1) After a compliance account is established under § 96.251(a) or § 73.31(a) or (b) of this chapter, the Administrator will record in the compliance account any CAIR SO_2 allowance allocated to any CAIR SO_2 unit at the source for each of the 30 years starting the later of 2010 or the year in which the compliance account is established and any CAIR SO_2 allowance allocated for each of the 30 years starting the later of 2010 or the year in which the compliance account is established and transferred to the source in accordance with subpart GGG of this part or subpart D of part 73 of this chapter.

(2) In 2011 and each year thereafter, after Administrator has completed all deductions under § 96.254(b), the Administrator will record in the compliance account any CAIR SO_2 allowance allocated to any CAIR SO_2 unit at the source for the new 30th year (*i.e.*, the year that is 30 years after the calendar year for which such deductions are or could be made) and any CAIR SO_2 allowance allocated for the new 30th year and transferred to the source in accordance with subpart GGG of this part or subpart D of part 73 of this chapter.

(b)(1) After a general account is established under § 96.251(b) or § 73.31(c) of this chapter, the Administrator will record in the general account any CAIR SO_2 allowance allocated for each of the 30 years starting the later of 2010 or the year in which the general account is established and transferred to the general account in accordance with subpart GGG of this part or subpart D of part 73 of this chapter.

(2) In 2011 and each year thereafter, after Administrator has completed all deductions under § 96.254(b), the Administrator will record in the general account any CAIR SO_2 allowance allocated for the new 30th year (*i.e.*, the year that is 30 years after the calendar

year for which such deductions are or could be made) and transferred to the general account in accordance with subpart GGG of this part or subpart D of part 73 of this chapter.

(c) *Serial numbers for allocated CAIR SO_2 allowances.* When recording the allocation of CAIR SO_2 allowances issued by a permitting authority under § 96.288, the Administrator will assign each such CAIR SO_2 allowance a unique identification number that will include digits identifying the year of the control period for which the CAIR SO_2 allowance is allocated.

§ 96.254 Compliance with CAIR SO_2 emissions limitation.

(a) *Allowance transfer deadline.* The CAIR SO_2 allowances are available to be deducted for compliance with a source's CAIR SO_2 emissions limitation for a control period in a given calendar year only if the CAIR SO_2 allowances:

(1) Were allocated for the control period in the year or a prior year;

(2) Are held in the compliance account as of the allowance transfer deadline for the control period or are transferred into the compliance account by a CAIR SO_2 allowance transfer correctly submitted for recordation under § 96.260 by the allowance transfer deadline for the control period; and

(3) Are not necessary for deduction for excess emissions for a prior control period under paragraph (d) of this section or for deduction under part 77 of this chapter.

(b) *Deductions for compliance.* Following the recordation, in accordance with § 96.261, of CAIR SO_2 allowance transfers submitted for recordation in a source's compliance account by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account CAIR SO_2 allowances available under paragraph (a) of this section in order to determine whether the source meets the CAIR SO_2 emissions limitation for the control period as follows:

(1) For a CAIR SO_2 source subject to an Acid Rain emissions limitation, the Administrator will, in the following order:

(i) Deduct the amount of CAIR SO_2 allowances, available under paragraph (a) of this section and not issued by a permitting authority under § 96.288, that is required under §§ 73.35(b) and (c) of this part. If there are sufficient CAIR SO_2 allowances to complete this deduction, the deduction will be treated as satisfying the requirements of §§ 73.35(b) and (c) of this chapter.

(ii) Deduct the amount of CAIR SO_2 allowances, available under paragraph (a) of this section and not issued by a permitting authority under § 96.288, that is required under §§ 73.35(d) and 77.5 of this part. If there are sufficient CAIR SO_2 allowances to complete this deduction, the deduction will be treated as satisfying the requirements of §§ 73.35(d) and 77.5 of this chapter.

(iii) Treating the CAIR SO_2 allowances deducted under paragraph (b)(1)(i) of this section as also being deducted under this paragraph (b)(1)(iii), deduct CAIR SO_2 allowances available under paragraph (a) of this section (including any issued by a permitting authority under § 96.288) in order to determine whether the source meets the CAIR SO_2 emissions limitation for the control period, as follows:

(A) Until the tonnage equivalent of the CAIR SO_2 allowances deducted equals, or exceeds in accordance with paragraphs (c)(1) and (2) of this section, the number of tons of total sulfur dioxide emissions, determined in accordance with subpart HHH of this part, from all CAIR SO_2 units at the source for the control period; or

(B) If there are insufficient CAIR SO_2 allowances to complete the deductions in paragraph (b)(1)(iii)(A) of this section, until no more CAIR SO_2 allowances available under paragraph (a) of this section (including any issued by a permitting authority under § 96.288) remain in the compliance account.

(2) For a CAIR SO_2 source not subject to an Acid Rain emissions limitation, the Administrator will deduct CAIR SO_2 allowances available under paragraph (a) of this section (including any issued by a permitting authority under § 96.288) in order to determine whether the source meets the CAIR SO_2 emissions limitation for the control period, as follows:

(i) Until the tonnage equivalent of the CAIR SO_2 allowances deducted equals, or exceeds in accordance with paragraphs (c)(1) and (2) of this section, the number of tons of total sulfur dioxide emissions, determined in accordance with subpart HHH of this part, from all CAIR SO_2 units at the source for the control period; or

(ii) If there are insufficient CAIR SO_2 allowances to complete the deductions in paragraph (b)(2)(i) of this section, until no more CAIR SO_2 allowances available under paragraph (a) of this section (including any issued by a permitting authority under § 96.288) remain in the compliance account.

(c)(1) *Identification of CAIR SO_2 allowances by serial number.* The CAIR authorized account representative for a source's compliance account may request that specific CAIR SO_2 allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the Administrator by the allowance transfer deadline for the control period and include, in a format prescribed by the Administrator, the identification of the CAIR SO_2 source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct CAIR SO_2 allowances under paragraph (b) or (d) of this section from the source's compliance account, in the absence of an identification or in the case of a partial identification of CAIR SO_2 allowances by serial number under paragraph (c)(1) of this section, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any CAIR SO_2 allowances that were allocated to the units at the source for a control period before 2010, in the order of recordation;

(ii) Any CAIR SO_2 allowances that were allocated to any unit for a control period before 2010 and transferred and recorded in the compliance account pursuant to subpart GGG of this part or subpart D of part 73 of this chapter, in the order of recordation;

(iii) Any CAIR SO_2 allowances that were allocated to the units at the source for a control period during 2010 through 2014, in the order of recordation;

(iv) Any CAIR SO_2 allowances that were allocated to any unit for a control period during 2010 through 2014 and transferred and recorded in the compliance account pursuant to subpart GGG of this part or subpart D of part 73 of this chapter, in the order of recordation;

(v) Any CAIR SO_2 allowances that were allocated to the units at the source for a control period in 2015 or later, in the order of recordation; and

(vi) Any CAIR SO_2 allowances that were allocated to any unit for a control period in 2015 or later and transferred and recorded in the compliance account pursuant to subpart GGG of this part or subpart D of part 73 of this chapter, in the order of recordation.

(d) *Deductions for excess emissions.* (1) After making the deductions for compliance under paragraph (b) of this section for a control period in a calendar year in which the CAIR SO_2 source has excess emissions, the Administrator will deduct from the source's compliance account the tonnage equivalent in CAIR SO_2 allowances, allocated for the control period in the immediately following calendar year (including any issued by a permitting authority under § 96.288), equal to, or exceeding in accordance with paragraphs (c)(1) and (2) of this section, 3 times the number of tons of the source's excess emissions.

(2) Any allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the CAIR SO_2 source or the CAIR SO_2 units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violations, as ordered under the Clean Air Act or applicable State law.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) or (d) of this section.

(f) *Administrator's action on submissions.* (1) The Administrator may review and conduct independent audits concerning any submission under the CAIR SO_2 Trading Program and make appropriate adjustments of the information in the submissions.

(2) The Administrator may deduct CAIR SO_2 allowances from or transfer CAIR SO_2 allowances to a source's compliance account based on the information in the submissions, as adjusted under paragraph (f)(1) of this section.

§ 96.255 Banking.

(a) CAIR SO_2 allowances may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any CAIR SO_2 allowance that is held in a compliance account or a general account will remain in such account unless and until the CAIR SO_2 allowance is deducted or transferred under § 96.254, § 96.256, or subpart GGG of this part.

§ 96.256 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any CAIR SO_2 Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the CAIR authorized account representative for the account.

§ 96.257 Closing of general accounts.

(a) The CAIR authorized account representative of a general account may submit to the Administrator a request to close the account, which shall include a correctly submitted allowance transfer under § 96.260 for any CAIR SO_2 allowances in the account to one or more other CAIR SO_2 Allowance Tracking System accounts.

(b) If a general account has no allowance transfers in or out of the account for a 12-month period or longer and does not contain any CAIR SO_2 allowances, the Administrator may notify the CAIR authorized account representative for the account that the account will be closed following 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted transfer of CAIR SO_2 allowances into the account under § 96.260 or a statement submitted by the CAIR authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

Subpart GGG—CAIR SO_2 Allowance Transfers

§ 96.260 Submission of CAIR SO_2 allowance transfers.

(a) A CAIR authorized account representative seeking recordation of a CAIR SO_2 allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the CAIR SO_2 allowance transfer shall include the following elements, in a format specified by the Administrator:

(1) The account numbers of both the transferor and transferee accounts;

(2) The serial number of each CAIR SO_2 allowance that is in the transferor account and is to be transferred; and

(3) The name and signature of the CAIR authorized account representatives of the transferor and transferee accounts and the dates signed.

(b)(1) The CAIR authorized account representative for the transferee account can meet the requirements in paragraph (a)(3) of this section by submitting, in a format prescribed by the Administrator, a statement signed by the CAIR authorized account representative and identifying each account into which any transfer of allowances, submitted on or after the date on which the Administrator receives such statement, is authorized. Such authorization shall be binding on any CAIR authorized account representative for such account and shall apply to all transfers into the account that are submitted on or after such date of receipt, unless and until the Administrator receives a statement signed by the CAIR authorized account representative retracting the authorization for the account.

(2) The statement under paragraph (b)(1) of this section shall include the following: ''By this signature I authorize any transfer of allowances into each account listed herein, except that I do not waive any remedies under State or Federal law to obtain correction of any erroneous transfers into such accounts. This authorization shall be binding on any CAIR authorized account representative for such account unless and until a statement signed by the CAIR authorized account representative retracting this authorization for the account is received by the Administrator.''

§ 96.261 EPA recordation.

(a) Within 5 business days (except as necessary to perform a transfer in perpetuity of CAIR SO_2 allowances allocated to a CAIR SO_2 unit or as provided in paragraph (b) of this section) of receiving a CAIR SO_2 allowance transfer, the Administrator will record a CAIR SO_2 allowance transfer by moving each CAIR SO_2 allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under § 96.260; and

(2) The transferor account includes each CAIR SO_2 allowance identified by serial number in the transfer.

(b) A CAIR SO_2 allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any CAIR SO_2 allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 96.254 for the control period immediately before such allowance transfer deadline.

(c) Where a CAIR SO_2 allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§ 96.262 Notification.

(a) *Notification of recordation.* Within 5 business days of recordation of a CAIR SO_2 allowance transfer under § 96.261, the Administrator will notify the CAIR authorized account representatives of both the transferor and transferee accounts.

(b) *Notification of non-recordation.* Within 10 business days of receipt of a CAIR SO_2 allowance transfer that fails to meet the requirements of § 96.261(a), the Administrator will notify the CAIR authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a CAIR SO_2 allowance transfer for recordation following notification of non-recordation.

Subpart HHH—Monitoring and Reporting

§ 96.270 General requirements.

The owners and operators, and to the extent applicable, the CAIR designated representative, of a CAIR SO_2 unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and in subparts F and G of part 75 of this chapter. For purposes of complying with such requirements, the definitions in § 96.202 and in § 72.2 of this chapter shall apply, and the terms ''affected unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') in part 75 of this chapter shall be deemed to refer to the terms ''CAIR SO_2 unit,'' ''CAIR designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') respectively, as defined in § 96.202. The owner or operator of a unit that is not a CAIR SO_2 unit but that is monitored under § 75.16(b)(2) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a CAIR SO_2 unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each CAIR SO_2 unit shall:

(1) Install all monitoring systems required under this subpart for monitoring SO_2 mass emissions and individual unit heat input (including all systems required to monitor SO_2 concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.11 and 75.16 of this chapter);

(2) Successfully complete all certification tests required under § 96.271 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* The owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a CAIR SO_2 unit that commences commercial operation before July 1, 2008, by January 1, 2009.

(2) For the owner or operator of a CAIR SO_2 unit that commences commercial operation on or after July 1, 2008, by the later of the following dates:

(i) January 1, 2009; or

(ii) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation.

(3) For the owner or operator of a CAIR SO_2 unit for which construction of a new stack or flue or installation of add-on SO_2 emission controls is completed after the applicable deadline under paragraph (b)(1), (2), (4), or (5) of this section, by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on SO_2 emissions controls.

(4) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section, for the owner or operator of a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, by the date specified in § 96.284(b).

(5) Notwithstanding the dates in paragraphs (b)(1) and (2) of this section and solely for purposes of § 96.206(c)(2), for the owner or operator of a CAIR SO_2 opt-in unit under subpart III of this part, by the date on which the CAIR SO_2 opt-in unit enters the CAIR SO_2 Trading Program as provided in § 96.284(g).

(c) *Reporting data.* (1) Except as provided in paragraph (c)(2) of this section, the owner or operator of a CAIR SO_2 unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for SO_2 concentration, SO_2 emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine SO_2 mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter or section 2.4 of appendix D to part 75 of this chapter, as applicable.

(2) The owner or operator of a CAIR SO_2 unit that does not meet the applicable compliance date set forth in paragraph (b)(3) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report substitute data using the applicable missing data procedures in subpart D of or appendix D to part 75 of this chapter, in lieu of the maximum potential (or, as appropriate, minimum potential) values, for a parameter if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation under paragraph (b)(3) of this section.

(d) *Prohibitions.* (1) No owner or operator of a CAIR SO_2 unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 96.275.

(2) No owner or operator of a CAIR SO_2 unit shall operate the unit so as to discharge, or allow to be discharged, SO_2 emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a CAIR SO_2 unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording SO_2 mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a CAIR SO_2 unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 96.205 that is in effect;

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

(iii) The CAIR designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 96.271(d)(3)(i).

§ 96.271 Initial certification and recertification procedures.

(a) The owner or operator of a CAIR SO_2 unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 96.270(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendix B and appendix D to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 96.270(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under § § 75.16(b)(2)(ii) of this chapter for apportioning the SO_2 mass emissions measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.11 or § 75.16 of this chapter, the CAIR designated representative shall resubmit the petition to the Administrator under § 96.275(a) to determine whether the approval applies under the CAIR SO_2 Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a CAIR SO_2 unit shall comply with the following initial certification and recertification procedures, for a continuous monitoring system (*i.e.*, a continuous emission monitoring system and an excepted monitoring system under appendix D to part 75 of this chapter) under § 96.270(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under § 96.270(a)(1) (including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 96.270(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 96.270(a)(1) that may significantly affect the ability of the system to accurately measure or record SO_2 mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: Replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter system under § 96.270(a)(1) is subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* Paragraphs (d)(3)(i) through (iv) of this section apply to both initial certification and recertification of a continuous monitoring system under § 96.270(a)(1). For recertifications, replace the words ''certification'' and ''initial certification'' with the word ''recertification'', replace the word ''certified'' with the word ''recertified,'' and follow the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter in lieu of the procedures in paragraph (d)(3)(v) of this section.

(i) *Notification of certification.* The CAIR designated representative shall submit to the permitting authority, the appropriate EPA Regional Office, and the Administrator written notice of the dates of certification testing, in accordance with § 96.273.

(ii) *Certification application.* The CAIR designated representative shall submit to the permitting authority a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the CAIR SO_2 Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the permitting authority.

(iv) *Certification application approval process.* The permitting authority will issue a written notice of approval or disapproval of the certification application to the owner or operator within 120 days of receipt of the complete certification application under paragraph (d)(3)(ii) of this section. In the event the permitting authority does not issue such a notice within such 120-day period, each monitoring system that meets the applicable performance requirements of part 75 of this chapter and is included in the certification application will be deemed certified for use under the CAIR SO_2 Trading Program.

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

(B) *Incomplete application notice.* If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the CAIR designated representative must submit the additional information required to complete the certification application. If the CAIR designated representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter). The owner or operator shall follow the procedures for loss of certification in paragraph (d)(3)(v) of this section for each monitoring system that is disapproved for initial certification.

(D) *Audit decertification.* The permitting authority or, for a CAIR SO_2 opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 96.272(b).

(v) *Procedures for loss of certification.* If the permitting authority or the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(*1*) For a disapproved SO_2 pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of SO_2 and the maximum potential flow rate, as defined in sections 2.1.1.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(*2*) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(*3*) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(B) The CAIR designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

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

(e) *Initial certification and recertification procedures for units using the low mass emission excepted methodology under § 75.19 of this chapter.* The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) *Certification/recertification procedures for alternative monitoring systems.* The CAIR designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 96.272 Out of control periods.

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

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 96.271 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority or, for a CAIR SO_2 opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority or the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 96.271 for each disapproved monitoring system.

§ 96.273 Notifications.

The CAIR designated representative for a CAIR SO_2 unit shall submit written notice to the permitting authority and the Administrator in accordance with § 75.61 of this chapter, except that if the unit is not subject to an Acid Rain emissions limitation, the notification is only required to be sent to the permitting authority.

§ 96.274 Recordkeeping and reporting.

(a) *General provisions.* The CAIR designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements in subparts F and G of part 75 of this chapter, and the requirements of § 96.210(e)(1).

(b) *Monitoring plans.* The owner or operator of a CAIR SO_2 unit shall comply with requirements of § 75.62 of this chapter and, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart III of this part, §§ 96.283 and 96.284(a).

(c) *Certification applications.* The CAIR designated representative shall submit an application to the permitting authority within 45 days after completing all initial certification or recertification tests required under § 96.271, including the information required under § 75.63 of this chapter.

(d) *Quarterly reports.* The CAIR designated representative shall submit quarterly reports, as follows:

(1) The CAIR designated representative shall report the SO_2 mass emissions data and heat input data for the CAIR SO_2 unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2008, the calendar quarter covering January 1, 2009 through March 31, 2009; or

(ii) For a unit that commences commercial operation on or after July 1, 2008, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 96.270(b), unless that quarter is the third or fourth quarter of 2008, in which case reporting shall commence in the quarter covering January 1, 2009 through March 31, 2009.

(2) The CAIR designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.64 of this chapter.

(3) For CAIR SO_2 units that are also subject to an Acid Rain emissions limitation or the CAIR NO_X Annual Trading Program or CAIR NO_X Ozone Season Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the SO_2 mass emission data, heat input data, and other information required by this subpart.

(e) *Compliance certification.* The CAIR designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications; and

(2) For a unit with add-on SO_2 emission controls and for all hours where SO_2 data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate SO_2 emissions.

§ 96.275 Petitions.

(a) The CAIR designated representative of a CAIR SO_2 unit that is subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator, in consultation with the permitting authority.

(b) The CAIR designated representative of a CAIR SO_2 unit that is not subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by both the permitting authority and the Administrator.

§ 96.276 Additional requirements to provide heat input data.

The owner or operator of a CAIR SO_2 unit that monitors and reports SO_2 mass emissions using a SO_2 concentration system and a flow system shall also monitor and report heat input rate at the unit level using the procedures set forth in part 75 of this chapter.

Subpart III—CAIR SO_2 Opt-in Units

§ 96.280 Applicability.

A CAIR SO_2 opt-in unit must be a unit that:

(a) Is located in the State;

(b) Is not a CAIR SO_2 unit under § 96.204 and is not covered by a retired unit exemption under § 96.205 that is in effect;

(c) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect and is not an opt-in source under part 74 of this chapter;

(d) Has or is required or qualified to have a title V operating permit or other federally enforceable permit; and

(e) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of subpart HHH of this part.

§ 96.281 General.

(a) Except as otherwise provided in §§ 96.201 through 96.204, §§ 96.206 through 96.208, and subparts BBB and CCC and subparts FFF through HHH of this part, a CAIR SO_2 opt-in unit shall be treated as a CAIR SO_2 unit for purposes of applying such sections and subparts of this part.

(b) Solely for purposes of applying, as provided in this subpart, the requirements of subpart HHH of this part to a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, such unit shall be treated as a CAIR SO_2 unit before issuance of a CAIR opt-in permit for such unit.

§ 96.282 CAIR designated representative.

Any CAIR SO_2 opt-in unit, and any unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, located at the same source as one or more CAIR SO_2 units shall have the same CAIR designated representative and alternate CAIR designated representative as such CAIR SO_2 units.

§ 96.283 Applying for CAIR opt-in permit.

(a) *Applying for initial CAIR opt-in permit.* The CAIR designated representative of a unit meeting the requirements for a CAIR SO_2 opt-in unit in § 96.280 may apply for an initial CAIR opt-in permit at any time, except as provided under § 96.286(f) and (g), and, in order to apply, must submit the following:

(1) A complete CAIR permit application under § 96.222;

(2) A certification, in a format specified by the permitting authority, that the unit:

(i) Is not a CAIR SO_2 unit under § 96.204 and is not covered by a retired unit exemption under § 96.205 that is in effect;

(ii) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(iii) Is not and, so long as the unit is a CAIR opt-in unit, will not become, an opt-in source under part 74 of this chapter;

(iv) Vents all of its emissions to a stack; and

(v) Has documented heat input for more than 876 hours during the 6 months immediately preceding submission of the CAIR permit application under § 96.222;

(3) A monitoring plan in accordance with subpart HHH of this part;

(4) A complete certificate of representation under § 96.213 consistent with § 96.282, if no CAIR designated representative has been previously designated for the source that includes the unit; and

(5) A statement, in a format specified by the permitting authority, whether the CAIR designated representative requests that the unit be allocated CAIR SO_2 allowances under § 96.288(c) (subject to the conditions in §§ 96.284(h) and 96.286(g)).

(b) *Duty to reapply.* (1) The CAIR designated representative of a CAIR SO_2 opt-in unit shall submit a complete CAIR permit application under § 96.222 to renew the CAIR opt-in unit permit in accordance with the permitting authority's regulations for title V operating permits, or permitting authority's regulations for other federally enforceable permits if applicable, addressing permit renewal.

(2) Unless the permitting authority issues a notification of acceptance of withdrawal of the CAIR opt-in unit from the CAIR SO_2 Trading Program in accordance with § 96.286 or the unit becomes a CAIR SO_2 unit under § 96.204, the CAIR SO_2 opt-in unit shall remain subject to the requirements for a CAIR SO_2 opt-in unit, even if the CAIR designated representative for the CAIR SO_2 opt-in unit fails to submit a CAIR permit application that is required for renewal of the CAIR opt-in permit under paragraph (b)(1) of this section.

§ 96.284 Opt-in process.

The permitting authority will issue or deny a CAIR opt-in permit for a unit for which an initial application for a CAIR opt-in permit under § 96.283 is submitted in accordance with the following:

(a) *Interim review of monitoring plan.* The permitting authority and the Administrator will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a CAIR opt-in permit under § 96.283. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the SO_2 emissions rate and heat input of the unit are monitored and reported in accordance with subpart HHH of this part. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(b) *Monitoring and reporting.* (1)(i) If the permitting authority and the Administrator determine that the monitoring plan is sufficient under paragraph (a) of this section, the owner or operator shall monitor and report the SO_2 emissions rate and the heat input of the unit and all other applicable parameters, in accordance with subpart HHH of this part, starting on the date of certification of the appropriate monitoring systems under subpart HHH of this part and continuing until a CAIR opt-in permit is denied under § 96.284(f) or, if a CAIR opt-in permit is issued, the date and time when the unit is withdrawn from the CAIR SO_2 Trading Program in accordance with § 96.286.

(ii) The monitoring and reporting under paragraph (b)(1)(i) of this section shall include the entire control period immediately before the date on which the unit enters the CAIR SO_2 Trading Program under § 96.284(g), during which period monitoring system availability must not be less than 90 percent under subpart HHH of this part and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the SO_2 emissions rate and the heat input of the unit are monitored and reported in accordance with subpart HHH of this part for one or more control periods, in addition to the control period under paragraph (b)(1)(ii) of this section, during which control periods monitoring system availability is not less than 90 percent under subpart HHH of this part and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the CAIR SO_2 Trading Program under § 96.284(g), such information shall be used as provided in paragraphs (c) and (d) of this section.

(c) *Baseline heat input.* The unit's baseline heat rate shall equal:

(1) If the unit's SO_2 emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit's total heat input (in mmBtu) for the control period; or

(2) If the unit's SO_2 emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, the average of the amounts of the unit's total heat input (in mmBtu) for the control period under paragraph (b)(1)(ii) of this section and the control periods under paragraph (b)(2) of this section.

(d) *Baseline SO_2 emission rate.* The unit's baseline SO_2 emission rate shall equal:

(1) If the unit's SO_2 emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit's SO_2 emissions rate (in lb/mmBtu) for the control period;

(2) If the unit's SO_2 emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit does not have add-on SO_2 emission controls during any such control periods, the average of the amounts of the unit's SO_2 emissions rate (in lb/mmBtu) for the control period under paragraph (b)(1)(ii) of this section and the control periods under paragraph (b)(2) of this section; or

(3) If the unit's SO_2 emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit has add-on SO_2 emission controls during any such control periods, the average of the amounts of the unit's SO_2 emissions rate (in lb/mmBtu) for such control period during which the unit has add-on SO_2 emission controls.

(e) *Issuance of CAIR opt-in permit.* After calculating the baseline heat input and the baseline SO_2 emissions rate for the unit under paragraphs (c) and (d) of this section and if the permitting authority determines that the CAIR designated representative shows that the unit meets the requirements for a CAIR SO_2 opt-in unit in § 96.280 and meets the elements certified in § 96.283(a)(2), the permitting authority will issue a CAIR opt-in permit. The permitting authority will provide a copy of the CAIR opt-in permit to the Administrator, who will then establish a compliance account for the source that includes the CAIR SO_2 opt-in unit unless the source already has a compliance account.

(f) *Issuance of denial of CAIR opt-in permit.* Notwithstanding paragraphs (a) through (e) of this section, if at any time before issuance of a CAIR opt-in permit for the unit, the permitting authority determines that the CAIR designated representative fails to show that the unit meets the requirements for a CAIR SO_2 opt-in unit in § 96.280 or meets the elements certified in § 96.283(a)(2), the permitting authority will issue a denial of a CAIR SO_2 opt-in permit for the unit.

(g) *Date of entry into CAIR SO_2 Trading Program.* A unit for which an initial CAIR opt-in permit is issued by the permitting authority shall become a CAIR SO_2 opt-in unit, and a CAIR SO_2 unit, as of the later of January 1, 2010 or January 1 of the first control period during which such CAIR opt-in permit is issued.

(h) *Repowered CAIR SO_2 opt-in unit.* (1) If CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR SO_2 opt-in unit of CAIR SO_2 allowances under § 96.288(c) and such unit is repowered after its date of entry into the CAIR SO_2 Trading Program under paragraph (g) of this section, the repowered unit shall be treated as a CAIR SO_2 opt-in unit replacing the original CAIR SO_2 opt-in unit, as of the date of start-up of the repowered unit's combustion chamber.

(2) Notwithstanding paragraphs (c) and (d) of this section, as of the date of start-up under paragraph (h)(1) of this section, the repowered unit shall be deemed to have the same date of commencement of operation, date of commencement of commercial operation, baseline heat input, and baseline SO_2 emission rate as the original CAIR SO_2 opt-in unit, and the original CAIR SO_2 opt-in unit shall no longer be treated as a CAIR opt-in unit or a CAIR SO_2 unit.

§ 96.285 CAIR opt-in permit contents.

(a) Each CAIR opt-in permit will contain:

(1) All elements required for a complete CAIR permit application under § 96.222;

(2) The certification in § 96.283(a)(2);

(3) The unit's baseline heat input under § 96.284(c);

(4) The unit's baseline SO_2 emission rate under § 96.284(d);

(5) A statement whether the unit is to be allocated CAIR SO_2 allowances under § 96.288(c) (subject to the conditions in §§ 96.284(h) and 96.286(g));

(6) A statement that the unit may withdraw from the CAIR SO_2 Trading Program only in accordance with § 96.286; and

(7) A statement that the unit is subject to, and the owners and operators of the unit must comply with, the requirements of § 96.287.

(b) Each CAIR opt-in permit is deemed to incorporate automatically the definitions of terms under § 96.202 and, upon recordation by the Administrator under subpart FFF or GGG of this part or this subpart, every allocation, transfer, or deduction of CAIR SO_2 allowances to or from the compliance account of the source that includes a CAIR SO_2 opt-in unit covered by the CAIR opt-in permit.

§ 96.286 Withdrawal from CAIR SO_2 Trading Program.

Except as provided under paragraph (g) of this section, a CAIR SO_2 opt-in unit may withdraw from the CAIR SO_2 Trading Program, but only if the permitting authority issues a notification to the CAIR designated representative of the CAIR SO_2 opt-in unit of the acceptance of the withdrawal of the CAIR SO_2 opt-in unit in accordance with paragraph (d) of this section.

(a) *Requesting withdrawal.* In order to withdraw a CAIR opt-in unit from the CAIR SO_2 Trading Program, the CAIR designated representative of the CAIR SO_2 opt-in unit shall submit to the permitting authority a request to withdraw effective as of midnight of December 31 of a specified calendar year, which date must be at least 4 years after December 31 of the year of entry into the CAIR SO_2 Trading Program under § 96.284(g). The request must be submitted no later than 90 days before the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a CAIR SO_2 opt-in unit covered by a request under paragraph (a) of this section may withdraw from the CAIR SO_2 Trading Program and the CAIR opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the CAIR SO_2 opt-in unit must meet the requirement to hold CAIR SO_2 allowances under § 96.206(c) and cannot have any excess emissions.

(2) After the requirement for withdrawal under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the CAIR SO_2 opt-in unit CAIR SO_2 allowances equal in number to and allocated for the same or a prior control period as any CAIR SO_2 allowances allocated to the CAIR SO_2 opt-in unit under § 96.188 for any control period for which the withdrawal is to be effective. If there are no remaining CAIR SO_2 units at the source, the Administrator will close the compliance account, and the owners and operators of the CAIR SO_2 opt-in unit may submit a CAIR SO_2 allowance transfer for any remaining CAIR SO_2 allowances to another CAIR SO_2 Allowance Tracking System in accordance with subpart GGG of this part.

(c) *Notification.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of CAIR SO_2 allowances required), the permitting authority will issue a notification to the CAIR designated representative of the CAIR SO_2 opt-in unit of the acceptance of the withdrawal of the CAIR SO_2 opt-in unit as of midnight on December 31 of the calendar year for which the withdrawal was requested.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the permitting authority will issue a notification to the CAIR designated representative of the CAIR SO_2 opt-in unit that the CAIR SO_2 opt-in unit's request to withdraw is denied. Such CAIR SO_2 opt-in unit shall continue to be a CAIR SO_2 opt-in unit.

(d) *Permit amendment.* After the permitting authority issues a notification under paragraph (c)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the CAIR permit covering the CAIR SO_2 opt-in unit to terminate the CAIR opt-in permit for such unit as of the effective date specified under paragraph (c)(1) of this section. The unit shall continue to be a CAIR SO_2 opt-in unit until the effective date of the termination and shall comply with all requirements under the CAIR SO_2 Trading Program concerning any control periods for which the unit is a CAIR SO_2 opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(e) *Reapplication upon failure to meet conditions of withdrawal.* If the permitting authority denies the CAIR SO_2 opt-in unit's request to withdraw, the CAIR designated representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(f) *Ability to reapply to the CAIR SO_2 Trading Program.* Once a CAIR SO_2 opt-in unit withdraws from the CAIR SO_2 Trading Program and its CAIR opt-in permit is terminated under this section, the CAIR designated representative may not submit another application for a CAIR opt-in permit under § 96.283 for such CAIR SO_2 opt-in unit before the date that is 4 years after the date on which the withdrawal became effective. Such new application for a CAIR opt-in permit will be treated as an initial application for a CAIR opt-in permit under § 96.284.

(g) *Inability to withdraw.* Notwithstanding paragraphs (a) through (f) of this section, a CAIR SO_2 opt-in unit shall not be eligible to withdraw from the CAIR SO_2 Trading Program if the CAIR designated representative of the CAIR SO_2 opt-in unit requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to the CAIR SO_2 opt-in unit of CAIR SO_2 allowances under § 96.288(c).

§ 96.287 Change in regulatory status.

(a) *Notification.* If a CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204, then the CAIR designated representative shall notify in writing the permitting authority and the Administrator of such change in the CAIR SO_2 opt-in unit's regulatory status, within 30 days of such change.

(b) *Permitting authority's and Administrator's actions.* (1) If a CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204, the permitting authority will revise the CAIR SO_2 opt-in unit's CAIR opt-in permit to meet the requirements of a CAIR permit under § 96.223 as of the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204.

(2)(i) The Administrator will deduct from the compliance account of the source that includes a CAIR SO_2 opt-in unit that becomes a CAIR SO_2 unit under § 96.204, CAIR SO_2 allowances equal in number to and allocated for the same or a prior control period as:

(A) Any CAIR SO_2 allowances allocated to the CAIR SO_2 opt-in unit under § 96.288 for any control period after the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204; and

(B) If the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204 is not December 31, the CAIR SO_2 allowances allocated to the CAIR SO_2 opt-in unit under § 96.288 for the control period that includes the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204, multiplied by the ratio of the number of days, in the control period, starting with the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204 divided by the total number of days in the control period and rounded to the nearest whole allowance as appropriate.

(ii) The CAIR designated representative shall ensure that the compliance account of the source that includes the CAIR SO_2 unit that becomes a CAIR SO_2 unit under § 96.204 contains the CAIR SO_2 allowances necessary for completion of the deduction under paragraph (b)(2)(i) of this section.

(3)(i) For every control period after the date on which a CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204, the CAIR SO_2 opt-in unit will be treated, solely for purposes of CAIR SO_2 allowance allocations under § 96.242, as a unit that commences operation on the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204 and will be allocated CAIR SO_2 allowances under § 96.242.

(ii) Notwithstanding paragraph (b)(3)(i) of this section, if the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204 is not January 1, the following number of CAIR SO_2 allowances will be allocated to the CAIR SO_2 opt-in unit (as a CAIR SO_2 unit) under § 96.242 for the control period that includes the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204:

(A) The number of CAIR SO_2 allowances otherwise allocated to the CAIR SO_2 opt-in unit (as a CAIR SO_2 unit) under § 96.242 for the control period multiplied by;

(B) The ratio of the number of days, in the control period, starting with the date on which the CAIR SO_2 opt-in unit becomes a CAIR SO_2 unit under § 96.204, divided by the total number of days in the control period; and

(C) Rounded to the nearest whole allowance as appropriate.

§ 96.288 SO_2 allowance allocations to CAIR SO_2 opt-in units.

(a) *Timing requirements.* (1) When the CAIR opt-in permit is issued under § 96.284(e), the permitting authority will allocate CAIR SO_2 allowances to the CAIR SO_2 opt-in unit, and submit to the Administrator the allocation for the control period in which a CAIR SO_2 opt-in unit enters the CAIR SO_2 Trading Program under § 96.284(g), in accordance with paragraph (b) or (c) of this section.

(2) By no later than October 31 of the control period in which a CAIR opt-in unit enters the CAIR SO_2 Trading Program under § 96.284(g) and October 31 of each year thereafter, the permitting authority will allocate CAIR SO_2 allowances to the CAIR SO_2 opt-in unit, and submit to the Administrator the allocation for the control period that includes such submission deadline and in which the unit is a CAIR SO_2 opt-in unit, in accordance with paragraph (b) or (c) of this section.

(b) *Calculation of allocation.* For each control period for which a CAIR SO_2 opt-in unit is to be allocated CAIR SO_2 allowances, the permitting authority will allocate in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the CAIR SO_2 allowance allocation will be the lesser of:

(i) The CAIR SO_2 opt-in unit's baseline heat input determined under § 96.284(c); or

(ii) The CAIR SO_2 opt-in unit's heat input, as determined in accordance with subpart HHH of this part, for the immediately prior control period, except when the allocation is being calculated for the control period in which the CAIR SO_2 opt-in unit enters the CAIR SO_2 Trading Program under § 96.284(g).

(2) The SO_2 emission rate (in lb/mmBtu) used for calculating CAIR SO_2 allowance allocations will be the lesser of:

(i) The CAIR SO_2 opt-in unit's baseline SO_2 emissions rate (in lb/mmBtu) determined under § 96.284(d) and multiplied by 70 percent; or

(ii) The most stringent State or Federal SO_2 emissions limitation applicable to the CAIR SO_2 opt-in unit at any time during the control period for which CAIR SO_2 allowances are to be allocated.

(3) The permitting authority will allocate CAIR SO_2 allowances to the CAIR SO_2 opt-in unit with a tonnage equivalent equal to, or less than by the smallest possible amount, the heat input under paragraph (b)(1) of this section, multiplied by the SO_2 emission rate under paragraph (b)(2) of this section, and divided by 2,000 lb/ton.

(c) Notwithstanding paragraph (b) of this section and if the CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR SO_2 opt-in unit of CAIR SO_2 allowances under this paragraph (subject to the conditions in §§ 96.284(h) and 96.286(g)), the permitting authority will allocate to the CAIR SO_2 opt-in unit as follows:

(1) For each control period in 2010 through 2014 for which the CAIR SO_2 opt-in unit is to be allocated CAIR SO_2 allowances,

(i) The heat input (in mmBtu) used for calculating CAIR SO_2 allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The SO_2 emission rate (in lb/mmBtu) used for calculating CAIR SO_2 allowance allocations will be the lesser of:

(A) The CAIR SO_2 opt-in unit's baseline SO_2 emissions rate (in lb/mmBtu) determined under § 96.284(d); or

(B) The most stringent State or Federal SO_2 emissions limitation applicable to the CAIR SO_2 opt-in unit at any time during the control period in which the CAIR SO_2 opt-in unit enters the CAIR SO_2 Trading Program under § 96.284(g).

(iii) The permitting authority will allocate CAIR SO_2 allowances to the CAIR SO_2 opt-in unit with a tonnage equivalent equal to, or less than by the smallest possible amount, the heat input under paragraph (c)(1)(i) of this section, multiplied by the SO_2 emission rate under paragraph (c)(1)(ii) of this section, and divided by 2,000 lb/ton.

(2) For each control period in 2015 and thereafter for which the CAIR SO_2 opt-in unit is to be allocated CAIR SO_2 allowances,

(i) The heat input (in mmBtu) used for calculating the CAIR SO_2 allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The SO_2 emission rate (in lb/mmBtu) used for calculating the CAIR SO_2 allowance allocation will be the lesser of:

(A) The CAIR SO_2 opt-in unit's baseline SO_2 emissions rate (in lb/mmBtu) determined under § 96.284(d) multiplied by 10 percent; or

(B) The most stringent State or Federal SO_2 emissions limitation applicable to the CAIR SO_2 opt-in unit at any time during the control period for which CAIR SO_2 allowances are to be allocated.

(iii) The permitting authority will allocate CAIR SO_2 allowances to the CAIR SO_2 opt-in unit with a tonnage equivalent equal to, or less than by the smallest possible amount, the heat input under paragraph (c)(2)(i) of this section, multiplied by the SO_2 emission rate under paragraph (c)(2)(ii) of this section, and divided by 2,000 lb/ton.

(d) *Recordation.* (1) The Administrator will record, in the compliance account of the source that includes the CAIR SO_2 opt-in unit, the CAIR SO_2 allowances allocated by the permitting authority to the CAIR SO_2 opt-in unit under paragraph (a)(1) of this section.

(2) By December 1 of the control period in which a CAIR opt-in unit enters the CAIR SO_2 Trading Program under § 96.284(g), and December 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the CAIR SO_2 opt-in unit, the CAIR SO_2 allowances allocated by the permitting authority to the CAIR SO_2 opt-in unit under paragraph (a)(2) of this section.

■ 4. Part 96 is amended by adding subparts AAAA through CCCC, adding and reserving subpart DDDD and adding subparts EEEE through IIII to read as follows:

Subpart AAAA—CAIR NO_X Ozone Season Trading Program General Provisions

Subpart BBBB—CAIR Designated Representative for CAIR NO_X Ozone Season Sources

Subpart CCCC—Permits

Subpart DDDD—[Reserved]

Subpart EEEE—CAIR NO_X Ozone Season Allowance Allocations

Subpart FFFF—CAIR NO_X Ozone Season Allowance Tracking System

Subpart GGGG—CAIR NO_X Ozone Season Allowance Transfers

Subpart HHHH—Monitoring and Reporting

Subpart IIII—CAIR NO_X Ozone Season Opt-in Units

Subpart AAAA—CAIR NO_X Ozone Season Trading Program General Provisions

§ 96.301 Purpose.

This subpart and subparts BBBB through IIII establish the model rule comprising general provisions and the designated representative, permitting, allowance, monitoring, and opt-in provisions for the State Clean Air Interstate Rule (CAIR) NO_X Ozone Season Trading Program, under section 110 of the Clean Air Act and § 51.123 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides. The owner or operator of a unit or a source shall comply with the requirements of this subpart and subparts BBBB through IIII as a matter of federal law only if the State with jurisdiction over the unit and the source incorporates by reference such subparts or otherwise adopts the requirements of such subparts in accordance with § 51.123(aa)(1) or (2), of this chapter, the State submits to the Administrator one or more revisions of the State implementation plan that include such adoption, and the Administrator approves such revisions. If the State adopts the requirements of such subparts in accordance with § 51.123(aa)(1) or (2), (bb), or (dd) of this chapter, then the State authorizes the Administrator to assist the State in implementing the CAIR NO_X Ozone Season Trading Program by carrying out the functions set forth for the Administrator in such subparts.

§ 96.302 Definitions.

The terms used in this subpart and subparts BBBB through IIII shall have the meanings set forth in this section as follows:

Account number means the identification number given by the Administrator to each CAIR NO_X Ozone Season Allowance Tracking System account.

Acid Rain emissions limitation means a limitation on emissions of sulfur dioxide or nitrogen oxides under the Acid Rain Program.

Acid Rain Program means a multi-state sulfur dioxide and nitrogen oxides air pollution control and emission reduction program established by the Administrator under title IV of the CAA and parts 72 through 78 of this chapter.

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

Allocate or *allocation* means, with regard to CAIR NO_X Ozone Season allowances issued under subpart EEEE, the determination by the permitting authority or the Administrator of the amount of such CAIR NO_X Ozone Season allowances to be initially credited to a CAIR NO_X Ozone Season unit or a new unit set-aside and, with regard to CAIR NO_X Ozone Season allowances issued under § 96.388 or § 51.123(aa)(2)(iii)(A) of this chapter, the determination by the permitting authority of the amount of such CAIR NO_X Ozone Season allowances to be initially credited to a CAIR NO_X Ozone Season unit.

Allowance transfer deadline means, for a control period, midnight of November 30, if it is a business day, or, if November 30 is not a business day, midnight of the first business day thereafter immediately following the control period and is the deadline by which a CAIR NO_X Ozone Season allowance transfer must be submitted for recordation in a CAIR NO_X Ozone Season source's compliance account in order to be used to meet the source's CAIR NO_X Ozone Season emissions limitation for such control period in accordance with § 96.354.

Alternate CAIR designated representative means, for a CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source in accordance with subparts BBBB and IIII of this part, to act on behalf of the CAIR designated representative in matters pertaining to the CAIR NO_X Ozone Season Trading Program. If the CAIR NO_X Ozone Season source is also a CAIR NO_X source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR NO_X Annual Trading Program. If the CAIR NO_X Ozone Season source is also a CAIR SO_2 source, then this natural person shall be the same person as the alternate CAIR designated representative under the CAIR SO_2 Trading Program. If the CAIR NO_X Ozone Season source is also subject to the Acid Rain Program, then this natural person shall be the same person as the alternate designated representative under the Acid Rain Program.

Automated data acquisition and handling system or *DAHS* means that component of the continuous emission monitoring system, or other emissions monitoring system approved for use under subpart HHHH of this part, designed to interpret and convert individual output signals from pollutant concentration monitors, flow monitors, diluent gas monitors, and other component parts of the monitoring system to produce a continuous record of the measured parameters in the measurement units required by subpart HHHH of this part.

Boiler means an enclosed fossil- or other-fuel-fired combustion device used to produce heat and to transfer heat to recirculating water, steam, or other medium.

Bottoming-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful thermal energy and at least some of the reject heat from the useful thermal energy application or process is then used for electricity production.

CAIR authorized account representative means, with regard to a general account, a responsible natural person who is authorized, in accordance with subparts BBBB and IIII of this part, to transfer and otherwise dispose of CAIR NO_X Ozone Season allowances held in the general account and, with regard to a compliance account, the CAIR designated representative of the source.

CAIR designated representative means, for a CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source, the natural person who is authorized by the owners and operators of the source and all such units at the source, in accordance with subparts BBBB and IIII of this part, to represent and legally bind each owner and operator in matters pertaining to the CAIR NO_X Ozone Season Trading Program. If the CAIR NO_X Ozone Season source is also a CAIR NO_X source, then this natural person shall be the same person as the CAIR designated representative under the CAIR NO_X Annual Trading Program. If the CAIR NO_X Ozone Season source is also a CAIR SO_2 source, then this natural person shall be the same person as the CAIR designated representative under the CAIR SO_2 Trading Program. If the CAIR NO_X Ozone Season source is also subject to the Acid Rain Program, then this natural person shall be the same person as the designated representative under the Acid Rain Program.

CAIR NO_X Annual Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AA through II of this part and § 51.123 of this chapter, as a means of mitigating interstate transport of fine particulates and nitrogen oxides.

CAIR NO_X Ozone Season allowance means a limited authorization issued by the permitting authority under subpart EEEE of this part, § 96.388, or § 51.123(aa)(2)(iii)(A), (bb)(2)(iii) or (iv), or (dd)(3) or (4) of this chapter to emit one ton of nitrogen oxides during a control period of the specified calendar year for which the authorization is allocated or of any calendar year thereafter under the CAIR NO_X Ozone Season Trading Program or a limited authorization issued by the permitting authority for a control period during 2003 through 2008 under the NO_X Budget Trading Program to emit one ton of nitrogen oxides during a control period, provided that the provision in § 51.121(b)(2)(i)(E) of this chapter shall not be used in applying this definition. An authorization to emit nitrogen oxides that is not issued under provisions of a State implementation plan that meet the requirements of § 51.121(p) of this chapter or § 51.123(aa)(1) or (2), (and (bb)(1)), (bb)(2), or (dd) of this chapter shall not be a CAIR NO_X Ozone Season allowance.

CAIR NO_X Ozone Season allowance deduction or *deduct CAIR NO_X Ozone Season allowances* means the permanent withdrawal of CAIR NO_X Ozone Season allowances by the Administrator from a compliance account in order to account for a specified number of tons of total nitrogen oxides emissions from all CAIR NO_X Ozone Season units at a CAIR NO_X Ozone Season source for a control period, determined in accordance with subpart HHHH of this part, or to account for excess emissions.

CAIR NO_X Ozone Season Allowance Tracking System means the system by which the Administrator records allocations, deductions, and transfers of CAIR NO_X Ozone Season allowances under the CAIR NO_X Ozone Season Trading Program. Such allowances will be allocated, held, deducted, or transferred only as whole allowances.

CAIR NO_X Ozone Season Allowance Tracking System account means an account in the CAIR NO_X Ozone Season Allowance Tracking System established by the Administrator for purposes of recording the allocation, holding, transferring, or deducting of CAIR NO_X Ozone Season allowances.

CAIR NO_X Ozone Season allowances held or *hold CAIR NO_X Ozone Season allowances* means the CAIR NO_X Ozone Season allowances recorded by the Administrator, or submitted to the Administrator for recordation, in accordance with subparts FFFF, GGGG, and IIII of this part, in a CAIR NO_X Ozone Season Allowance Tracking System account.

CAIR NO_X Ozone Season emissions limitation means, for a CAIR NO_X Ozone Season source, the tonnage equivalent of the CAIR NO_X Ozone Season allowances available for deduction for the source under § 96.354(a) and (b) for a control period.

CAIR NO_X Ozone Season Trading Program means a multi-state nitrogen oxides air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAAA through IIII of this part and § 51.123 of this chapter, as a means of mitigating interstate transport of ozone and nitrogen oxides.

CAIR NO_X Ozone Season source means a source that includes one or more CAIR NO_X Ozone Season units.

CAIR NO_X Ozone Season unit means a unit that is subject to the CAIR NO_X Ozone Season Trading Program under § 96.304 and, except for purposes of § 96.305 and subpart EEEE of this part, a CAIR NO_X Ozone Season opt-in unit under subpart IIII of this part.

CAIR NO_X source means a source that includes one or more CAIR NO_X units.

CAIR NO_X unit means a unit that is subject to the CAIR NO_X Annual Trading Program under § 96.104 and a CAIR NO_X opt-in unit under subpart II of this part.

CAIR permit means the legally binding and federally enforceable written document, or portion of such document, issued by the permitting authority under subpart CCCC of this part, including any permit revisions, specifying the CAIR NO_X Ozone Season Trading Program requirements applicable to a CAIR NO_X Ozone Season source, to each CAIR NO_X Ozone Season unit at the source, and to the owners and operators and the CAIR designated representative of the source and each such unit.

CAIR SO_2 source means a source that includes one or more CAIR SO_2 units.

CAIR SO_2 Trading Program means a multi-state sulfur dioxide air pollution control and emission reduction program approved and administered by the Administrator in accordance with subparts AAA through III of this part and § 51.124 of this chapter, as a means of mitigating interstate transport of fine particulates and sulfur dioxide.

CAIR SO_2 unit means a unit that is subject to the CAIR SO_2 Trading Program under § 96.204 and a CAIR SO_2 opt-in unit under subpart III of this part.

Clean Air Act or *CAA* means the Clean Air Act, 42 U.S.C. 7401, *et seq.*

Coal means any solid fuel classified as anthracite, bituminous, subbituminous, or lignite.

Coal-derived fuel means any fuel (whether in a solid, liquid, or gaseous state) produced by the mechanical, thermal, or chemical processing of coal.

Coal-fired means:

(1) Except for purposes of subpart EEEE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during any year; or

(2) For purposes of subpart EEEE of this part, combusting any amount of coal or coal-derived fuel, alone or in combination with any amount of any other fuel, during a specified year.

Cogeneration unit means a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine:

(1) Having equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy; and

(2) Producing during the 12-month period starting on the date the unit first produces electricity and during any calendar year after which the unit first produces electricity—

(i) For a topping-cycle cogeneration unit,

(A) Useful thermal energy not less than 5 percent of total energy output; and

(B) Useful power that, when added to one-half of useful thermal energy produced, is not less then 42.5 percent of total energy input, if useful thermal energy produced is 15 percent or more of total energy output, or not less than 45 percent of total energy input, if useful thermal energy produced is less than 15 percent of total energy output.

(ii) For a bottoming-cycle cogeneration unit, useful power not less than 45 percent of total energy input.

Combustion turbine means:

(1) An enclosed device comprising a compressor, a combustor, and a turbine and in which the flue gas resulting from the combustion of fuel in the combustor passes through the turbine, rotating the turbine; and

(2) If the enclosed device under paragraph (1) of this definition is combined cycle, any associated heat recovery steam generator and steam turbine.

Commence commercial operation means, with regard to a unit serving a generator:

(1) To have begun to produce steam, gas, or other heated medium used to generate electricity for sale or use, including test generation, except as provided in § 96.305.

(i) For a unit that is a CAIR NO_X Ozone Season unit under § 96.304 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit that is a CAIR NO_X Ozone Season unit under § 96.304 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 96.305, for a unit that is not a CAIR NO_X Ozone Season unit under § 96.304 on the date the unit commences commercial operation as defined in paragraph (1) of this definition and is not a unit under paragraph (3) of this definition, the unit's date for commencement of commercial operation shall be the date on which the unit becomes a CAIR NO_X Ozone Season unit under § 96.304.

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(3) Notwithstanding paragraph (1) of this definition and except as provided in § 96.384(h) or § 96.387(b)(3), for a CAIR NO_X Ozone Season opt-in unit or

a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart IIII of this part, the unit's date for commencement of commercial operation shall be the date on which the owner or operator is required to start monitoring and reporting the NO_X emissions rate and the heat input of the unit under § 96.384(b)(1)(i).

(i) For a unit with a date for commencement of commercial operation as defined in paragraph (3) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of commercial operation.

(ii) For a unit with a date for commencement of commercial operation as defined in paragraph (3) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of commercial operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(4) Notwithstanding paragraphs (1) through (3) of this definition, for a unit not serving a generator producing electricity for sale, the unit's date of commencement of operation shall also be the unit's date of commencement of commercial operation.

Commence operation means:

(1) To have begun any mechanical, chemical, or electronic process, including, with regard to a unit, start-up of a unit's combustion chamber, except as provided in § 96.305.

(i) For a unit that is a CAIR NO_X Ozone Season unit under § 96.304 on the date the unit commences operation as defined in paragraph (1) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit that is a CAIR NO_X Ozone Season unit under § 96.304 on the date the unit commences operation as defined in paragraph (1) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

(2) Notwithstanding paragraph (1) of this definition and except as provided in § 96.305, for a unit that is not a CAIR NO_X Ozone Season unit under § 96.304 on the date the unit commences operation as defined in paragraph (1) of this definition and is not a unit under paragraph (3) of this definition, the unit's date for commencement of operation shall be the date on which the unit becomes a CAIR NO_X Ozone Season unit under § 96.304.

(i) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit with a date for commencement of operation as defined in paragraph (2) of this definition and that is subsequently replaced by a unit at the same source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1),(2), or (3) of this definition as appropriate.

(3) Notwithstanding paragraph (1) of this definition and except as provided in § 96.384(h) or § 96.387(b)(3), for a CAIR NO_X Ozone Season opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart IIII of this part, the unit's date for commencement of operation shall be the date on which the owner or operator is required to start monitoring and reporting the NO_X emissions rate and the heat input of the unit under § 96.384(b)(1)(i).

(i) For a unit with a date for commencement of operation as defined in paragraph (3) of this definition and that subsequently undergoes a physical change (other than replacement of the unit by a unit at the same source), such date shall remain the unit's date of commencement of operation.

(ii) For a unit with a date for commencement of operation as defined in paragraph (3) of this definition and that is subsequently replaced by a unit at the source (*e.g.*, repowered), the replacement unit shall be treated as a separate unit with a separate date for commencement of operation as defined in paragraph (1), (2), or (3) of this definition as appropriate.

Common stack means a single flue through which emissions from 2 or more units are exhausted.

Compliance account means a CAIR NO_X Ozone Season Allowance Tracking System account, established by the Administrator for a CAIR NO_X Ozone Season source under subpart FFFF or IIII of this part, in which any CAIR NO_X Ozone Season allowance allocations for the CAIR NO_X Ozone Season units at the source are initially recorded and in which are held any CAIR NO_X Ozone Season allowances available for use for a control period in order to meet the source's CAIR NO_X Ozone Season emissions limitation in accordance with § 96.354.

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

(1) A flow monitoring system, consisting of a stack flow rate monitor and an automated data acquisition and handling system and providing a permanent, continuous record of stack gas volumetric flow rate, in standard cubic feet per hour (scfh);

(2) A nitrogen oxides concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of NO_X emissions, in parts per million (ppm);

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

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

(5) A carbon dioxide monitoring system, consisting of a CO_2 pollutant concentration monitor (or an oxygen monitor plus suitable mathematical equations from which the CO_2 concentration is derived) and an automated data acquisition and handling system and providing a permanent, continuous record of CO_2 emissions, in percent CO_2; and

(6) An oxygen monitoring system, consisting of an O_2 concentration monitor and an automated data acquisition and handling system and providing a permanent, continuous record of O_2 in percent O_2.

Control period or *ozone season* means the period beginning May 1 of a calendar year and ending on September 30 of the same year, inclusive.

Emissions means air pollutants exhausted from a unit or source into the atmosphere, as measured, recorded, and reported to the Administrator by the CAIR designated representative and as determined by the Administrator in accordance with subpart HHHH of this part.

Excess emissions means any ton of nitrogen oxides emitted by the CAIR NO_X Ozone Season units at a CAIR NO_X Ozone Season source during a control period that exceeds the CAIR NO_X Ozone Season emissions limitation for the source.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material.

Fossil-fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

Fuel oil means any petroleum-based fuel (including diesel fuel or petroleum derivatives such as oil tar) and any recycled or blended petroleum products or petroleum by-products used as a fuel whether in a liquid, solid, or gaseous state.

General account means a CAIR NO_X Ozone Season Allowance Tracking System account, established under subpart FFFF of this part, that is not a compliance account.

Generator means a device that produces electricity.

Gross electrical output means, with regard to a cogeneration unit, electricity made available for use, including any such electricity used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Heat input means, with regard to a specified period of time, the product (in mmBtu/time) of the gross calorific value of the fuel (in Btu/lb) divided by 1,000,000 Btu/mmBtu and multiplied by the fuel feed rate into a combustion device (in lb of fuel/time), as measured, recorded, and reported to the Administrator by the CAIR designated representative and determined by the Administrator in accordance with subpart HHHH of this part and excluding the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

Heat input rate means the amount of heat input (in mmBtu) divided by unit operating time (in hr) or, with regard to a specific fuel, the amount of heat input attributed to the fuel (in mmBtu) divided by the unit operating time (in hr) during which the unit combusts the fuel.

Life-of-the-unit, firm power contractual arrangement means a unit participation power sales agreement under which a utility or industrial customer reserves, or is entitled to receive, a specified amount or percentage of nameplate capacity and associated energy generated by any specified unit and pays its proportional amount of such unit's total costs, pursuant to a contract:

(1) For the life of the unit;

(2) For a cumulative term of no less than 30 years, including contracts that permit an election for early termination; or

(3) For a period no less than 25 years or 70 percent of the economic useful life of the unit determined as of the time the unit is built, with option rights to purchase or release some portion of the nameplate capacity and associated energy generated by the unit at the end of the period.

Maximum design heat input means, starting from the initial installation of a unit, the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis as specified by the manufacturer of the unit, or, starting from the completion of any subsequent physical change in the unit resulting in a decrease in the maximum amount of fuel per hour (in Btu/hr) that a unit is capable of combusting on a steady state basis, such decreased maximum amount as specified by the person conducting the physical change.

Monitoring system means any monitoring system that meets the requirements of subpart HHHH of this part, including a continuous emissions monitoring system, an alternative monitoring system, or an excepted monitoring system under part 75 of this chapter.

Most stringent State or Federal NO_X emissions limitation means, with regard to a unit, the lowest NO_X emissions limitation (in terms of lb/mmBtu) that is applicable to the unit under State or Federal law, regardless of the averaging period to which the emissions limitation applies.

Nameplate capacity means, starting from the initial installation of a generator, the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings) as specified by the manufacturer of the generator or, starting from the completion of any subsequent physical change in the generator resulting in an increase in the maximum electrical generating output (in MWe) that the generator is capable of producing on a steady state basis and during continuous operation (when not restricted by seasonal or other deratings), such increased maximum amount as specified by the person conducting the physical change.

Oil-fired means, for purposes of subpart EEEE of this part, combusting fuel oil for more than 15.0 percent of the annual heat input in a specified year.

Operator means any person who operates, controls, or supervises a CAIR NO_X Ozone Season unit or a CAIR NO_X Ozone Season source and shall include, but not be limited to, any holding company, utility system, or plant manager of such a unit or source.

Owner means any of the following persons:

(1) With regard to a CAIR NO_X Ozone Season source or a CAIR NO_X Ozone Season unit at a source, respectively:

(i) Any holder of any portion of the legal or equitable title in a CAIR NO_X Ozone Season unit at the source or the CAIR NO_X Ozone Season unit;

(ii) Any holder of a leasehold interest in a CAIR NO_X Ozone Season unit at the source or the CAIR NO_X Ozone Season unit; or

(iii) Any purchaser of power from a CAIR NO_X Ozone Season unit at the source or the CAIR NO_X Ozone Season unit under a life-of-the-unit, firm power contractual arrangement; provided that, unless expressly provided for in a leasehold agreement, owner shall not include a passive lessor, or a person who has an equitable interest through such lessor, whose rental payments are not based (either directly or indirectly) on the revenues or income from such CAIR NO_X Ozone Season unit; or

(2) With regard to any general account, any person who has an ownership interest with respect to the CAIR NO_X Ozone Season allowances held in the general account and who is subject to the binding agreement for the CAIR authorized account representative to represent the person's ownership interest with respect to CAIR NO_X Ozone Season allowances.

Permitting authority means the State air pollution control agency, local agency, other State agency, or other agency authorized by the Administrator to issue or revise permits to meet the requirements of the CAIR NO_X Ozone

Season Trading Program in accordance with subpart CCCC of this part or, if no such agency has been so authorized, the Administrator.

Potential electrical output capacity means 33 percent of a unit's maximum design heat input, divided by 3,413 Btu/kWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 hr/yr.

Receive or receipt of means, when referring to the permitting authority or the Administrator, to come into possession of a document, information, or correspondence (whether sent in hard copy or by authorized electronic transmission), as indicated in an official correspondence log, or by a notation made on the document, information, or correspondence, by the permitting authority or the Administrator in the regular course of business.

Recordation, record, or *recorded* means, with regard to CAIR NO_X Ozone Season allowances, the movement of CAIR NO_X Ozone Season allowances by the Administrator into or between CAIR NO_X Ozone Season Allowance Tracking System accounts, for purposes of allocation, transfer, or deduction.

Reference method means any direct test method of sampling and analyzing for an air pollutant as specified in § 75.22 of this chapter.

Repowered means, with regard to a unit, replacement of a coal-fired boiler with one of the following coal-fired technologies at the same source as the coal-fired boiler:

(1) Atmospheric or pressurized fluidized bed combustion;

(2) Integrated gasification combined cycle;

(3) Magnetohydrodynamics;

(4) Direct and indirect coal-fired turbines;

(5) Integrated gasification fuel cells; or

(6) As determined by the Administrator in consultation with the Secretary of Energy, a derivative of one or more of the technologies under paragraphs (1) through (5) of this definition and any other coal-fired technology capable of controlling multiple combustion emissions simultaneously with improved boiler or generation efficiency and with significantly greater waste reduction relative to the performance of technology in widespread commercial use as of January 1, 2005.

Serial number means, for a CAIR NO_X Ozone Season allowance, the unique identification number assigned to each CAIR NO_X Ozone Season allowance by the Administrator.

Sequential use of energy means:

(1) For a topping-cycle cogeneration unit, the use of reject heat from electricity production in a useful thermal energy application or process; or

(2) For a bottoming-cycle cogeneration unit, the use of reject heat from useful thermal energy application or process in electricity production.

Source means all buildings, structures, or installations located in one or more contiguous or adjacent properties under common control of the same person or persons. For purposes of section 502(c) of the Clean Air Act, a "source," including a "source" with multiple units, shall be considered a single "facility."

State means one of the States or the District of Columbia that adopts the CAIR NO_X Ozone Season Trading Program pursuant to § 51.123(aa)(1) or (2), (bb), or (dd) of this chapter.

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

(1) In person;

(2) By United States Postal Service; or

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

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

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

Ton means 2,000 pounds. For the purpose of determining compliance with the CAIR NO_X Ozone Season emissions limitation, total tons of nitrogen oxides emissions for a control period shall be calculated as the sum of all recorded hourly emissions (or the mass equivalent of the recorded hourly emission rates) in accordance with subpart HHHH of this part, but with any remaining fraction of a ton equal to or greater than 0.50 tons deemed to equal one ton and any remaining fraction of a ton less than 0.50 tons deemed to equal zero tons.

Topping-cycle cogeneration unit means a cogeneration unit in which the energy input to the unit is first used to produce useful power, including electricity, and at least some of the reject heat from the electricity production is then used to provide useful thermal energy.

Total energy input means, with regard to a cogeneration unit, total energy of all forms supplied to the cogeneration unit, excluding energy produced by the cogeneration unit itself.

Total energy output means, with regard to a cogeneration unit, the sum of useful power and useful thermal energy produced by the cogeneration unit.

Unit means a stationary, fossil-fuel-fired boiler or combustion turbine or other stationary, fossil-fuel-fired combustion device.

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

Unit operating hour or *hour of unit operation* means an hour in which a unit combusts any fuel.

Useful power means, with regard to a cogeneration unit, electricity or mechanical energy made available for use, excluding any such energy used in the power production process (which process includes, but is not limited to, any on-site processing or treatment of fuel combusted at the unit and any on-site emission controls).

Useful thermal energy means, with regard to a cogeneration unit, thermal energy that is:

(1) Made available to an industrial or commercial process (not a power production process), excluding any heat contained in condensate return or makeup water;

(2) Used in a heat application (e.g., space heating or domestic hot water heating); or

(3) Used in a space cooling application (i.e., thermal energy used by an absorption chiller).

Utility power distribution system means the portion of an electricity grid owned or operated by a utility and dedicated to delivering electricity to customers.

§ 96.303 Measurements, abbreviations, and acronyms.

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

Btu—British thermal unit.
CO_2—carbon dioxide.
1NO_X—nitrogen oxides.
hr—hour.
kW—kilowatt electrical.
kWh—kilowatt hour.
mmBtu—million Btu.
MWe—megawatt electrical.
MWh—megawatt hour.
O_2—oxygen.
ppm—parts per million.
lb—pound.
scfh—standard cubic feet per hour.
SO_2—sulfur dioxide.
H_2O—water.
yr-year.

§ 96.304 Applicability.

The following units in a State shall be CAIR NO_X Ozone Season units, and any source that includes one or more such units shall be a CAIR NO_X Ozone Season source, subject to the requirements of this subpart and subparts BBBB through HHHH of this part:

(a) Except as provided in paragraph (b) of this section, a stationary, fossil-fuel-fired boiler or stationary, fossil-fuel-fired combustion turbine serving at any time, since the start-up of a unit's combustion chamber, a generator with nameplate capacity of more than 25 MWe producing electricity for sale.

(b) For a unit that qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity and continues to qualify as a cogeneration unit, a cogeneration unit serving at any time a generator with nameplate capacity of more than 25 MWe and supplying in any calendar year more than one-third of the unit's potential electric output capacity or 219,000 MWh, whichever is greater, to any utility power distribution system for sale. If a unit qualifies as a cogeneration unit during the 12-month period starting on the date the unit first produces electricity but subsequently no longer qualifies as a cogeneration unit, the unit shall be subject to paragraph (a) of this section starting on the day on which the unit first no longer qualifies as a cogeneration unit.

§ 96.305 Retired unit exemption.

(a)(1) Any CAIR NO_X Ozone Season unit that is permanently retired and is not a CAIR NO_X Ozone Season opt-in unit shall be exempt from the CAIR NO_X Ozone Season Trading Program, except for the provisions of this section, § 96.302, § 96.303, § 96.304, § 96.306(c)(4) through (8), § 96.307, and subparts EEEE through GGGG of this part.

(2) The exemption under paragraph (a)(1) of this section shall become effective the day on which the CAIR NO_X Ozone Season unit is permanently retired. Within 30 days of the unit's permanent retirement, the CAIR designated representative shall submit a statement to the permitting authority otherwise responsible for administering any CAIR permit for the unit and shall submit a copy of the statement to the Administrator. The statement shall state, in a format prescribed by the permitting authority, that the unit was permanently retired on a specific date and will comply with the requirements of paragraph (b) of this section.

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

(b) *Special provisions.* (1) A unit exempt under paragraph (a) of this section shall not emit any nitrogen oxides, starting on the date that the exemption takes effect.

(2) The permitting authority will allocate CAIR NO_X Ozone Season allowances under subpart EEEE of this part to a unit exempt under paragraph (a) of this section.

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

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

(5) A unit exempt under paragraph (a) of this section and located at a source that is required, or but for this exemption would be required, to have a title V operating permit shall not resume operation unless the CAIR designated representative of the source submits a complete CAIR permit application under § 96.322 for the unit not less than 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2009 or the date on which the unit resumes operation.

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

(i) The date on which the CAIR designated representative submits a CAIR permit application for the unit under paragraph (b)(5) of this section;

(ii) The date on which the CAIR designated representative is required under paragraph (b)(5) of this section to submit a CAIR permit application for the unit; or

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

(7) For the purpose of applying monitoring, reporting, and recordkeeping requirements under subpart HHHH of this part, a unit that loses its exemption under paragraph (a) of this section shall be treated as a unit that commences operation and commercial operation on the first date on which the unit resumes operation.

§ 96.306 Standard requirements.

(a) *Permit requirements.* (1) The CAIR designated representative of each CAIR NO_X Ozone Season source required to have a title V operating permit and each CAIR NO_X Ozone Season unit required to have a title V operating permit at the source shall:

(i) Submit to the permitting authority a complete CAIR permit application under § 96.322 in accordance with the deadlines specified in § 96.321(a) and (b); and

(ii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review a CAIR permit application and issue or deny a CAIR permit.

(2) The owners and operators of each CAIR NO_X Ozone Season source required to have a title V operating permit and each CAIR NO_X Ozone Season unit required to have a title V operating permit at the source shall have a CAIR permit issued by the permitting authority under subpart CCCC of this part for the source and operate the source and the unit in compliance with such CAIR permit.

(3) Except as provided in subpart IIII of this part, the owners and operators of a CAIR NO_X Ozone Season source that is not otherwise required to have a title V operating permit and each CAIR NO_X Ozone Season unit that is not otherwise required to have a title V operating permit are not required to submit a CAIR permit application, and to have a CAIR permit, under subpart CCCC of this part for such CAIR NO_X Ozone Season source and such CAIR NO_X Ozone Season unit.

(b) *Monitoring, reporting, and recordkeeping requirements.* (1) The owners and operators, and the CAIR designated representative, of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of subpart HHHH of this part.

(2) The emissions measurements recorded and reported in accordance with subpart HHHH of this part shall be used to determine compliance by each CAIR NO_X Ozone Season source with the CAIR NO_X Ozone Season emissions

limitation under paragraph (c) of this section.

(c) *Nitrogen oxides ozone season emission requirements.* (1) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall hold, in the source's compliance account, CAIR NO_X Ozone Season allowances available for compliance deductions for the control period under § 96.354(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X Ozone Season units at the source, as determined in accordance with subpart HHHH of this part.

(2) A CAIR NO_X Ozone Season unit shall be subject to the requirements under paragraph (c)(1) of this section starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under § 96.370(b)(1), (2), (3), or (7).

(3) A CAIR NO_X Ozone Season allowance shall not be deducted, for compliance with the requirements under paragraph (c)(1) of this section, for a control period in a calendar year before the year for which the CAIR NO_X Ozone Season allowance was allocated.

(4) CAIR NO_X Ozone Season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X Ozone Season Allowance Tracking System accounts in accordance with subpart EEEE of this part.

(5) A CAIR NO_X Ozone Season allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_X Ozone Season Trading Program. No provision of the CAIR NO_X Ozone Season Trading Program, the CAIR permit application, the CAIR permit, or an exemption under § 96.305 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(6) A CAIR NO_X Ozone Season allowance does not constitute a property right.

(7) Upon recordation by the Administrator under subpart FFFF, GGGG, or IIII of this part, every allocation, transfer, or deduction of a CAIR NO_X Ozone Season allowance to or from a CAIR NO_X Ozone Season unit's compliance account is incorporated automatically in any CAIR permit of the source that includes the CAIR NO_X Ozone Season unit.

(d) *Excess emissions requirements.* (1) If a CAIR NO_X Ozone Season source emits nitrogen oxides during any control period in excess of the CAIR NO_X Ozone Season emissions limitation, then:

(i) The owners and operators of the source and each CAIR NO_X Ozone Season unit at the source shall surrender the CAIR NO_X Ozone Season allowances required for deduction under § 96.354(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law; and

(ii) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of this subpart, the Clean Air Act, and applicable State law.

(2) [Reserved]

(e) *Recordkeeping and reporting requirements.* (1) Unless otherwise provided, the owners and operators of the CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the Administrator.

(i) The certificate of representation under § 96.313 for the CAIR designated representative for the source and each CAIR NO_X Ozone Season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation under § 96.313 changing the CAIR designated representative.

(ii) All emissions monitoring information, in accordance with subpart HHHH of this part, provided that to the extent that subpart HHHH of this part provides for a 3-year period for recordkeeping, the 3-year period shall apply.

(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_X Ozone Season Trading Program.

(iv) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_X Ozone Season Trading Program or to demonstrate compliance with the requirements of the CAIR NO_X Ozone Season Trading Program.

(2) The CAIR designated representative of a CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit at the source shall submit the reports required under the CAIR NO_X Ozone Season Trading Program, including those under subpart HHHH of this part.

(f) *Liability.* (1) Each CAIR NO_X Ozone Season source and each CAIR NO_X Ozone Season unit shall meet the requirements of the CAIR NO_X Ozone Season Trading Program.

(2) Any provision of the CAIR NO_X Ozone Season Trading Program that applies to a CAIR NO_X Ozone Season source or the CAIR designated representative of a CAIR NO_X Ozone Season source shall also apply to the owners and operators of such source and of the CAIR NO_X Ozone Season units at the source.

(3) Any provision of the CAIR NO_X Ozone Season Trading Program that applies to a CAIR NO_X Ozone Season unit or the CAIR designated representative of a CAIR NO_X Ozone Season unit shall also apply to the owners and operators of such unit.

(g) *Effect on other authorities.* No provision of the CAIR NO_X Ozone Season Trading Program, a CAIR permit application, a CAIR permit, or an exemption under § 96.305 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X Ozone Season source or CAIR NO_X Ozone Season unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

§ 96.307 Computation of time.

(a) Unless otherwise stated, any time period scheduled, under the CAIR NO_X Ozone Season Trading Program, to begin on the occurrence of an act or event shall begin on the day the act or event occurs.

(b) Unless otherwise stated, any time period scheduled, under the CAIR NO_X Ozone Season Trading Program, to begin before the occurrence of an act or event shall be computed so that the period ends the day before the act or event occurs.

(c) Unless otherwise stated, if the final day of any time period, under the CAIR NO_X Ozone Season Trading Program, falls on a weekend or a State or Federal holiday, the time period shall be extended to the next business day.

§ 96.308 Appeal procedures.

The appeal procedures for decisions of the Administrator under the CAIR NO_X Ozone Season Trading Program are set forth in part 78 of this chapter.

Subpart BBBB—CAIR Designated Representative for CAIR NO_X Ozone Season Sources

§ 96.310 Authorization and responsibilities of CAIR designated representative.

(a) Except as provided under § 96.311, each CAIR NO_X Ozone Season source, including all CAIR NO_X Ozone Season units at the source, shall have one and only one CAIR designated representative, with regard to all matters under the CAIR NO_X Ozone Season Trading Program concerning the source or any CAIR NO_X Ozone Season unit at the source.

(b) The CAIR designated representative of the CAIR NO_X Ozone Season source shall be selected by an agreement binding on the owners and operators of the source and all CAIR NO_X Ozone Season units at the source and shall act in accordance with the certification statement in § 96.313(a)(4)(iv).

(c) Upon receipt by the Administrator of a complete certificate of representation under § 96.313, the CAIR designated representative of the source shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of the CAIR NO_X Ozone Season source represented and each CAIR NO_X Ozone Season unit at the source in all matters pertaining to the CAIR NO_X Ozone Season Trading Program, notwithstanding any agreement between the CAIR designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the CAIR designated representative by the permitting authority, the Administrator, or a court regarding the source or unit.

(d) No CAIR permit will be issued, no emissions data reports will be accepted, and no CAIR NO_X Ozone Season Allowance Tracking System account will be established for a CAIR NO_X Ozone Season unit at a source, until the Administrator has received a complete certificate of representation under § 96.313 for a CAIR designated representative of the source and the CAIR NO_X Ozone Season units at the source.

(e)(1) Each submission under the CAIR NO_X Ozone Season Trading Program shall be submitted, signed, and certified by the CAIR designated representative for each CAIR NO_X Ozone Season source on behalf of which the submission is made. Each such submission shall include the following certification statement by the CAIR designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) The permitting authority and the Administrator will accept or act on a submission made on behalf of owner or operators of a CAIR NO_X Ozone Season source or a CAIR NO_X Ozone Season unit only if the submission has been made, signed, and certified in accordance with paragraph (e)(1) of this section.

§ 96.311 Alternate CAIR designated representative.

(a) A certificate of representation under § 96.313 may designate one and only one alternate CAIR designated representative, who may act on behalf of the CAIR designated representative. The agreement by which the alternate CAIR designated representative is selected shall include a procedure for authorizing the alternate CAIR designated representative to act in lieu of the CAIR designated representative.

(b) Upon receipt by the Administrator of a complete certificate of representation under § 96.313, any representation, action, inaction, or submission by the alternate CAIR designated representative shall be deemed to be a representation, action, inaction, or submission by the CAIR designated representative.

(c) Except in this section and §§ 96.302, 96.310(a) and (d), 96.312, 96.313, 96.351, and 96.382 whenever the term ''CAIR designated representative'' is used in subparts AAAA through IIII of this part, the term shall be construed to include the CAIR designated representative or any alternate CAIR designated representative.

§ 96.312 Changing CAIR designated representative and alternate CAIR designated representative; changes in owners and operators.

(a) *Changing CAIR designated representative.* The CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 96.313. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new CAIR designated representative and the owners and operators of the CAIR NO_X Ozone Season source and the CAIR NO_X Ozone Season units at the source.

(b) *Changing alternate CAIR designated representative.* The alternate CAIR designated representative may be changed at any time upon receipt by the Administrator of a superseding complete certificate of representation under § 96.313. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR designated representative before the time and date when the Administrator receives the superseding certificate of representation shall be binding on the new alternate CAIR designated representative and the owners and operators of the CAIR NO_X Ozone Season source and the CAIR NO_X Ozone Season units at the source.

(c) *Changes in owners and operators.* (1) In the event a new owner or operator of a CAIR NO_X Ozone Season source or a CAIR NO_X Ozone Season unit is not included in the list of owners and operators in the certificate of representation under § 96.313, such new owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the CAIR designated representative and any alternate CAIR designated representative of the source or unit, and the decisions and orders of the permitting authority, the Administrator, or a court, as if the new owner or operator were included in such list.

(2) Within 30 days following any change in the owners and operators of a CAIR NO_X Ozone Season source or a CAIR NO_X Ozone Season unit, including the addition of a new owner or operator, the CAIR designated representative or any alternate CAIR designated representative shall submit a revision to the certificate of representation under § 96.313 amending the list of owners and operators to include the change.

§ 96.313 Certificate of representation.

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

(1) Identification of the CAIR NO_X Ozone Season source, and each CAIR NO_X Ozone Season unit at the source, for which the certificate of representation is submitted.

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

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

(4) The following certification statements by the CAIR designated representative and any alternate CAIR designated representative—

(i) ''I certify that I was selected as the CAIR designated representative or alternate CAIR designated representative, as applicable, by an agreement binding on the owners and operators of the source and each CAIR NO_X Ozone Season unit at the source.''

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR NO_X Ozone Season Trading Program on behalf of the owners and operators of the source and of each CAIR NO_X Ozone Season unit at the source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.''

(iii) ''I certify that the owners and operators of the source and of each CAIR NO_X Ozone Season unit at the source shall be bound by any order issued to me by the Administrator, the permitting authority, or a court regarding the source or unit.''

(iv) ''Where there are multiple holders of a legal or equitable title to, or a leasehold interest in, a CAIR NO_X Ozone Season unit, or where a customer purchases power from a CAIR NO_X Ozone Season unit under a life-of-the-unit, firm power contractual arrangement, I certify that: I have given a written notice of my selection as the 'CAIR designated representative' or 'alternate CAIR designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the source and of each CAIR NO_X Ozone Season unit at the source; and CAIR NO_X Ozone Season allowances and proceeds of transactions involving CAIR NO_X Ozone Season allowances will be deemed to be held or distributed in proportion to each holder's legal, equitable, leasehold, or contractual reservation or entitlement, except that, if such multiple holders have expressly provided for a different distribution of CAIR NO_X Ozone Season allowances by contract, CAIR NO_X Ozone Season allowances and proceeds of transactions involving CAIR NO_X Ozone Season allowances will be deemed to be held or distributed in accordance with the contract.''

(5) The signature of the CAIR designated representative and any alternate CAIR designated representative and the dates signed.

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

§ 96.314 Objections concerning CAIR designated representative.

(a) Once a complete certificate of representation under § 96.313 has been submitted and received, the permitting authority and the Administrator will rely on the certificate of representation unless and until a superseding complete certificate of representation under § 96.313 is received by the Administrator.

(b) Except as provided in § 96.312(a) or (b), no objection or other communication submitted to the permitting authority or the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the CAIR designated representative shall affect any representation, action, inaction, or submission of the CAIR designated representative or the finality of any decision or order by the permitting authority or the Administrator under the CAIR NO_X Ozone Season Trading Program.

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

Subpart CCCC—Permits

§ 96.320 General CAIR NO_X Ozone Season Trading Program permit requirements.

(a) For each CAIR NO_X Ozone Season source required to have a title V operating permit or required, under subpart IIII of this part, to have a title V operating permit or other federally enforceable permit, such permit shall include a CAIR permit administered by the permitting authority for the title V operating permit or the federally enforceable permit as applicable. The CAIR portion of the title V permit or other federally enforceable permit as applicable shall be administered in accordance with the permitting authority's title V operating permits regulations promulgated under part 70 or 71 of this chapter or the permitting authority's regulations for other federally enforceable permits as applicable, except as provided otherwise by this subpart and subpart IIII of this part.

(b) Each CAIR permit shall contain, with regard to the CAIR NO_X Ozone Season source and the CAIR NO_X Ozone Season units at the source covered by the CAIR permit, all applicable CAIR NO_X Ozone Season Trading Program, CAIR NO_X Annual Trading Program, and CAIR SO_2 Trading Program requirements and shall be a complete and separable portion of the title V operating permit or other federally enforceable permit under paragraph (a) of this section.

§ 96.321 Submission of CAIR permit applications.

(a) *Duty to apply.* The CAIR designated representative of any CAIR NO_X Ozone Season source required to have a title V operating permit shall submit to the permitting authority a complete CAIR permit application under § 96.322 for the source covering each CAIR NO_X Ozone Season unit at the source at least 18 months (or such lesser time provided by the permitting authority) before the later of January 1, 2009 or the date on which the CAIR NO_X Ozone Season unit commences operation.

(b) *Duty to Reapply.* For a CAIR NO_X Ozone Season source required to have a title V operating permit, the CAIR designated representative shall submit a complete CAIR permit application under § 96.322 for the source covering each CAIR NO_X Ozone Season unit at the source to renew the CAIR permit in accordance with the permitting authority's title V operating permits regulations addressing permit renewal.

§ 96.322 Information requirements for CAIR permit applications.

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

(a) Identification of the CAIR NO_X Ozone Season source;

(b) Identification of each CAIR NO_X Ozone Season unit at the CAIR NO_X Ozone Season source; and

(c) The standard requirements under § 96.306.

§ 96.323 CAIR permit contents and term.

(a) Each CAIR permit will contain, in a format prescribed by the permitting authority, all elements required for a complete CAIR permit application under § 96.322.

(b) Each CAIR permit is deemed to incorporate automatically the definitions of terms under § 96.302 and, upon recordation by the Administrator under subpart FFFF, GGGG, or IIII of this part, every allocation, transfer, or deduction of a CAIR NO_X Ozone Season allowance to or from the compliance account of the CAIR NO_X Ozone Season source covered by the permit.

(c) The term of the CAIR permit will be set by the permitting authority, as necessary to facilitate coordination of the renewal of the CAIR permit with issuance, revision, or renewal of the CAIR NO_X Ozone Season source's title V operating permit or other federally enforceable permit as applicable.

§ 96.324 CAIR permit revisions.

Except as provided in § 96.323(b), the permitting authority will revise the CAIR permit, as necessary, in accordance with the permitting authority's title V operating permits regulations or the permitting authority's regulations for other federally enforceable permits as applicable addressing permit revisions.

Subpart DDDD—[Reserved]

Subpart EEEE—CAIR NO_X Ozone Season Allowance Allocations

§ 96.340 State trading budgets.

(a) Except as provided in paragraph (b) of this section, the State trading budgets for annual allocations of CAIR NO_X Ozone Season allowances for the control periods in 2009 through 2014 and in 2015 and thereafter are respectively as follows:

State	State trading budget for 2009–2014 (tons)	State trading budget for 2015 and thereafter (tons)
Alabama	32,182	26,818
Arkansas	11,515	9,596
Connecticut	2,559	2,559
Delaware	2,226	1,855
District of Columbia	112	94
Florida	47,912	39,926
Illinois	30,701	28,981
Indiana	45,952	39,273
Iowa	14,263	11,886
Kentucky	36,045	30,587
Louisiana	17,085	14,238
Maryland	12,834	10,695
Massachusetts	7,551	6,293
Michigan	28,971	24,142
Mississippi	8,714	7,262
Missouri	26,678	22,231
New Jersey	6,654	5,545
New York	20,632	17,193
North Carolina	28,392	23,660
Ohio	45,664	39,945
Pennsylvania	42,171	35,143
South Carolina	15,249	12,707
Tennessee	22,842	19,035
Virginia	15,994	13,328
West Virginia	26,859	26,525
Wisconsin	17,987	14,989

(b) If a permitting authority issues additional CAIR NO_X Ozone Season allowance allocations under § 51.123(aa)(2)(iii)(A) of this chapter, the amount in the State trading budget for a control period in a calendar year will be the sum of the amount set forth for the State and for the year in paragraph (a) of this section and the amount of additional CAIR NO_X Ozone Season allowance allocations issued under § 51.123(aa)(2)(iii)(A) of this chapter for the year.

§ 96.341 Timing requirements for CAIR NO_X Ozone Season allowance allocations.

(a) By October 31, 2006, the permitting authority will submit to the Administrator the CAIR NO_X Ozone Season allowance allocations, in a format prescribed by the Administrator and in accordance with § 96.342(a) and (b), for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014.

(b)(1) By October 31, 2009 and October 31 of each year thereafter, the permitting authority will submit to the Administrator the CAIR NO_X Ozone Season allowance allocations, in a format prescribed by the Administrator and in accordance with § 96.342(a) and (b), for the control period in the sixth year after the year of the applicable deadline for submission under this paragraph.

(2) If the permitting authority fails to submit to the Administrator the CAIR NO_X Ozone Season allowance allocations in accordance with paragraph (b)(1), the Administrator will assume that the allocations of CAIR NO_X Ozone Season allowances for the applicable control period are the same as for the control period that immediately precedes the applicable control period, except that, if the applicable control period is in 2015, the Administrator will assume that the allocations equal 83 percent of the allocations for the control period that immediately precedes the applicable control period.

(c)(1) By July 31, 2009 and July 31 of each year thereafter, the permitting authority will submit to the Administrator the CAIR NO_X Ozone Season allowance allocations, in a format prescribed by the Administrator and in accordance with § 96.342(c), (a), and (d), for the control period in the year of the applicable deadline for submission under this paragraph.

(2) If the permitting authority fails to submit to the Administrator the CAIR NO_X Ozone Season allowance allocations in accordance with paragraph (c)(1) of this section, the Administrator will assume that the allocations of CAIR NO_X Ozone Season allowances for the applicable control period are the same as for the control period that immediately precedes the applicable control period, except that, if the applicable control period is in 2015, the Administrator will assume that the allocations equal 83 percent of the allocations for the control period that immediately precedes the applicable control period and except that any CAIR NO_X Ozone Season unit that would otherwise be allocated CAIR NO_X Ozone Season allowances under § 96.342(a) and (b), as well as under § 96.342(a), (c), and (d), for the applicable control period will be assumed to be allocated no CAIR NO_X Ozone Season allowances under § 96.342(a), (c), and (d) for the applicable control period.

§ 96.342 CAIR NO_X Ozone Season allowance allocations.

(a)(1) The baseline heat input (in mmBtu) used with respect to CAIR NO_X Ozone Season allowance allocations under paragraph (b) of this section for each CAIR NO_X Ozone Season unit will be:

(i) For units commencing operation before January 1, 2001 the average of the 3 highest amounts of the unit's adjusted control period heat input for 2000 through 2004, with the adjusted control period heat input for each year calculated as follows:

(A) If the unit is coal-fired during the year, the unit's control period heat input for such year is multiplied by 100 percent;

(B) If the unit is oil-fired during the year, the unit's control period heat input for such year is multiplied by 60 percent; and

(C) If the unit is not subject to paragraph (a)(1)(i)(A) or (B) of this section, the unit's control period heat input for such year is multiplied by 40 percent.

(ii) For units commencing operation on or after January 1, 2001 and operating each calendar year during a period of 5 or more consecutive calendar years, the average of the 3 highest amounts of the unit's total converted control period heat input over the first such 5 years.

(2)(i) A unit's control period heat input, and a unit's status as coal-fired or oil-fired, for a calendar year under paragraph (a)(1)(i) of this section, and a unit's total tons of NO_X emissions during a calendar year under paragraph (c)(3) of this section, will be determined in accordance with part 75 of this chapter, to the extent the unit was otherwise subject to the requirements of part 75 of this chapter for the year, or will be based on the best available data reported to the permitting authority for the unit, to the extent the unit was not otherwise subject to the requirements of part 75 of this chapter for the year.

(ii) A unit's converted control period heat input for a calendar year specified under paragraph (a)(1)(ii) of this section equals:

(A) Except as provided in paragraph (a)(2)(ii)(B) or (C) of this section, the control period gross electrical output of the generator or generators served by the unit multiplied by 7,900 Btu/kWh, if the unit is coal-fired for the year, or 6,675 Btu/kWh, if the unit is not coal-fired for the year, and divided by 1,000,000 Btu/mmBtu, provided that if a generator is served by 2 or more units, then the gross electrical output of the generator will be attributed to each unit in proportion to the unit's share of the total control period heat input of such units for the year;

(B) For a unit that is a boiler and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the total heat energy (in Btu) of the steam produced by the boiler during the control period, divided by 0.8 and by 1,000,000 Btu/mmBtu; or

(C) For a unit that is a combustion turbine and has equipment used to produce electricity and useful thermal energy for industrial, commercial, heating, or cooling purposes through the sequential use of energy, the control period gross electrical output of the enclosed device comprising the compressor, combustor, and turbine multiplied by 3,414 Btu/kWh, plus the total heat energy (in Btu) of the steam produced by any associated heat recovery steam generator during the control period divided by 0.8, and with the sum divided by 1,000,000 Btu/mmBtu.

(b)(1) For each control period in 2009 and thereafter, the permitting authority will allocate to all CAIR NO_X Ozone Season units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of CAIR NO_X Ozone Season allowances equal to 95 percent for a control period during 2009 through 2014, and 97 percent for a control period during 2015 and thereafter, of the tons of NO_X emissions in the State trading budget under § 96.340 (except as provided in paragraph (d) of this section).

(2) The permitting authority will allocate CAIR NO_X Ozone Season allowances to each CAIR NO_X Ozone Season unit under paragraph (b)(1) of this section in an amount determined by multiplying the total amount of CAIR NO_X Ozone Season allowances allocated under paragraph (b)(1) of this section by the ratio of the baseline heat input of such CAIR NO_X Ozone Season unit to the total amount of baseline heat input of all such CAIR NO_X Ozone Season units in the State and rounding to the nearest whole allowance as appropriate.

(c) For each control period in 2009 and thereafter, the permitting authority will allocate CAIR NO_X Ozone Season allowances to CAIR NO_X Ozone Season units in the State that commenced operation on or after January 1, 2001 and do not yet have a baseline heat input (as determined under paragraph (a) of this section), in accordance with the following procedures:

(1) The permitting authority will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated CAIR NO_X Ozone Season allowances equal to 5 percent for a control period in 2009 through 2013, and 3 percent for a control period in 2014 and thereafter, of the amount of tons of NO_X emissions in the State trading budget under § 96.340.

(2) The CAIR designated representative of such a CAIR NO_X Ozone Season unit may submit to the permitting authority a request, in a format specified by the permitting authority, to be allocated CAIR NO_X Ozone Season allowances, starting with the later of the control period in 2009 or the first control period after the control period in which the CAIR NO_X Ozone Season unit commences commercial operation and until the first control period for which the unit is allocated CAIR NO_X Ozone Season allowances under paragraph (b) of this section. The CAIR NO_X Ozone Season allowance allocation request must be submitted on or before April 1 before the first control period for which the CAIR NO_X Ozone Season allowances are requested and after the date on which the CAIR NO_X Ozone Season unit commences commercial operation.

(3) In a CAIR NO_X Ozone Season allowance allocation request under paragraph (c)(2) of this section, the CAIR designated representative may request for a control period CAIR NO_X Ozone Season allowances in an amount not exceeding the CAIR NO_X Ozone Season unit's total tons of NO_X emissions during the control period immediately before such control period.

(4) The permitting authority will review each CAIR NO_X Ozone Season allowance allocation request under paragraph (c)(2) of this section and will allocate CAIR NO_X Ozone Season allowances for each control period pursuant to such request as follows:

(i) The permitting authority will accept an allowance allocation request only if the request meets, or is adjusted by the permitting authority as necessary to meet, the requirements of paragraphs (c)(2) and (3) of this section.

(ii) On or after April 1 before the control period, the permitting authority will determine the sum of the CAIR NO_X Ozone Season allowances requested (as adjusted under paragraph (c)(4)(i) of this section) in all allowance allocation requests accepted under paragraph (c)(4)(i) of this section for the control period.

(iii) If the amount of CAIR NO_X Ozone Season allowances in the new unit set-aside for the control period is greater than or equal to the sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate the amount of CAIR NO_X Ozone Season allowances requested (as adjusted under paragraph (c)(4)(i) of this section) to each CAIR NO_X Ozone Season unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section.

(iv) If the amount of CAIR NO_X Ozone Season allowances in the new unit set-aside for the control period is less than the sum under paragraph (c)(4)(ii) of this section, then the permitting authority will allocate to each CAIR NO_X Ozone Season unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the CAIR NO_X Ozone Season allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of CAIR NO_X Ozone Season allowances in the new unit set-aside for the control period, divided by the sum determined under paragraph (c)(4)(ii) of this section, and rounded to the nearest whole allowance as appropriate.

(v) The permitting authority will notify each CAIR designated representative that submitted an allowance allocation request of the amount of CAIR NO_X Ozone Season allowances (if any) allocated for the control period to the CAIR NO_X Ozone Season unit covered by the request.

(d) If, after completion of the procedures under paragraph (c)(4) of this section for a control period, any unallocated CAIR NO_X Ozone Season allowances remain in the new unit set-aside for the control period, the permitting authority will allocate to each CAIR NO_X Ozone Season unit that was allocated CAIR NO_X Ozone Season allowances under paragraph (b) of this section an amount of CAIR NO_X Ozone Season allowances equal to the total amount of such remaining unallocated CAIR NO_X Ozone Season allowances, multiplied by the unit's allocation under paragraph (b) of this section, divided by 95 percent for a control period during 2009 through 2014, and 97 percent for a control period during 2015 and thereafter, of the amount of tons of NO_X emissions in the State trading budget under § 96.340, and rounded to the nearest whole allowance as appropriate.

Subpart FFFF—CAIR NO_X Ozone Season Allowance Tracking System

§ 96.350 [Reserved]

§ 96.351 Establishment of accounts.

(a) *Compliance accounts.* Except as provided in § 96.384(e), upon receipt of a complete certificate of representation under § 96.313, the Administrator will establish a compliance account for the CAIR NO_X Ozone Season source for which the certificate of representation was submitted, unless the source already has a compliance account.

(b) *General accounts*—(1) *Application for general account.*

(i) Any person may apply to open a general account for the purpose of holding and transferring CAIR NO_X Ozone Season allowances. An application for a general account may designate one and only one CAIR authorized account representative and one and only one alternate CAIR authorized account representative who may act on behalf of the CAIR authorized account representative. The agreement by which the alternate CAIR authorized account representative is selected shall include a procedure for authorizing the alternate CAIR authorized account representative to act in lieu of the CAIR authorized account representative.

(ii) A complete application for a general account shall be submitted to the Administrator and shall include the following elements in a format prescribed by the Administrator:

(A) Name, mailing address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the CAIR authorized account representative and any alternate CAIR authorized account representative;

(B) Organization name and type of organization, if applicable;

(C) A list of all persons subject to a binding agreement for the CAIR authorized account representative and any alternate CAIR authorized account representative to represent their ownership interest with respect to the CAIR NO_X Ozone Season allowances held in the general account;

(D) The following certification statement by the CAIR authorized account representative and any alternate CAIR authorized account representative: ''I certify that I was selected as the CAIR authorized account representative or the alternate CAIR authorized account representative, as applicable, by an agreement that is binding on all persons who have an ownership interest with respect to CAIR NO_X Ozone Season allowances held in the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the CAIR NO_X Ozone Season Trading Program on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Administrator or a court regarding the general account.''

(E) The signature of the CAIR authorized account representative and any alternate CAIR authorized account representative and the dates signed.

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

(2) *Authorization of CAIR authorized account representative.*

(i) Upon receipt by the Administrator of a complete application for a general account under paragraph (b)(1) of this section:

(A) The Administrator will establish a general account for the person or persons for whom the application is submitted.

(B) The CAIR authorized account representative and any alternate CAIR authorized account representative for the general account shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each person who has an ownership interest with respect to CAIR NO_X Ozone Season allowances held in the general account in all matters pertaining to the CAIR NO_X Ozone Season Trading Program, notwithstanding any agreement between the CAIR authorized account representative or any alternate CAIR authorized account representative and such person. Any such person shall be bound by any order or decision issued to the CAIR authorized account representative or any alternate CAIR authorized account representative by the Administrator or a court regarding the general account.

(C) Any representation, action, inaction, or submission by any alternate CAIR authorized account representative shall be deemed to be a representation, action, inaction, or submission by the CAIR authorized account representative.

(ii) Each submission concerning the general account shall be submitted, signed, and certified by the CAIR authorized account representative or any alternate CAIR authorized account representative for the persons having an ownership interest with respect to CAIR NO_X Ozone Season allowances held in the general account. Each such submission shall include the following certification statement by the CAIR authorized account representative or any alternate CAIR authorized account representative: ''I am authorized to make this submission on behalf of the persons having an ownership interest with respect to the CAIR NO_X Ozone Season allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(iii) The Administrator will accept or act on a submission concerning the general account only if the submission has been made, signed, and certified in accordance with paragraph (b)(2)(ii) of this section.

(3) *Changing CAIR authorized account representative and alternate CAIR authorized account representative; changes in persons with ownership interest.*

(i) The CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR NO_X Ozone Season allowances in the general account.

(ii) The alternate CAIR authorized account representative for a general account may be changed at any time upon receipt by the Administrator of a superseding complete application for a general account under paragraph (b)(1) of this section. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous alternate CAIR authorized account representative before the time and date when the Administrator receives the superseding application for a general account shall be binding on the new alternate CAIR authorized account representative and the persons with an ownership interest with respect to the CAIR NO_X Ozone Season allowances in the general account.

(iii)(A) In the event a new person having an ownership interest with respect to CAIR NO_X Ozone Season allowances in the general account is not included in the list of such persons in the application for a general account, such new person shall be deemed to be subject to and bound by the application for a general account, the representation, actions, inactions, and submissions of the CAIR authorized account representative and any alternate CAIR authorized account representative of the account, and the decisions and orders of the Administrator or a court, as if the new person were included in such list.

(B) Within 30 days following any change in the persons having an ownership interest with respect to CAIR NO_X Ozone Season allowances in the general account, including the addition of persons, the CAIR authorized account representative or any alternate CAIR authorized account representative shall submit a revision to the application for a general account amending the list of persons having an ownership interest with respect to the CAIR NO_X Ozone Season allowances in the general account to include the change.

(4) *Objections concerning CAIR authorized account representative.*

(i) Once a complete application for a general account under paragraph (b)(1) of this section has been submitted and received, the Administrator will rely on the application unless and until a superseding complete application for a general account under paragraph (b)(1) of this section is received by the Administrator.

(ii) Except as provided in paragraph (b)(3)(i) or (ii) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative for a general account shall affect any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative or the finality of any decision or order by the Administrator under the CAIR NO_X Ozone Season Trading Program.

(iii) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of the CAIR authorized account representative or any alternative CAIR authorized account representative for a general account, including private legal disputes concerning the proceeds of CAIR NO_X Ozone Season allowance transfers.

(c) *Account identification.* The Administrator will assign a unique identifying number to each account established under paragraph (a) or (b) of this section.

§ 96.352 Responsibilities of CAIR authorized account representative.

Following the establishment of a CAIR NO_X Ozone Season Allowance Tracking System account, all submissions to the Administrator pertaining to the account, including, but not limited to, submissions concerning the deduction or transfer of CAIR NO_X Ozone Season allowances in the account, shall be made only by the CAIR authorized account representative for the account.

§ 96.353 Recordation of CAIR NO_X Ozone Season allowance allocations.

(a) By December 1, 2006, the Administrator will record in the CAIR NO_X Ozone Season source's compliance account the CAIR NO_X Ozone Season allowances allocated for the CAIR NO_X Ozone Season units at a source, as submitted by the permitting authority in accordance with § 96.341(a), for the control periods in 2009, 2010, 2011, 2012, 2013, and 2014.

(b) By December 1, 2009, the Administrator will record in the CAIR NO_X Ozone Season source's compliance account the CAIR NO_X Ozone Season allowances allocated for the CAIR NO_X Ozone Season units at the source, as submitted by the permitting authority or as determined by the Administrator in accordance with § 96.341(b), for the control period in 2015.

(c) In 2011 and each year thereafter, after the Administrator has made all deductions (if any) from a CAIR NO_X Ozone Season source's compliance account under § 96.354, the Administrator will record in the CAIR NO_X Ozone Season source's compliance account the CAIR NO_X Ozone Season allowances allocated for the CAIR NO_X Ozone Season units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with § 96.341(b), for the control period in the sixth year after the year of the control period for which such deductions were or could have been made.

(d) By September 1, 2009 and September 1 of each year thereafter, the Administrator will record in the CAIR NO_X Ozone Season source's compliance account the CAIR NO_X Ozone Season allowances allocated for the CAIR NO_X Ozone Season units at the source, as submitted by the permitting authority or determined by the Administrator in accordance with § 96.341(c), for the control period in the year of the applicable deadline for recordation under this paragraph.

(e) *Serial numbers for allocated CAIR NO_X Ozone Season allowances.* When recording the allocation of CAIR NO_X Ozone Season allowances for a CAIR NO_X Ozone Season unit in a compliance account, the Administrator will assign each CAIR NO_X Ozone Season allowance a unique identification number that will include digits identifying the year of the control period for which the CAIR NO_X Ozone Season allowance is allocated.

§ 96.354 Compliance with CAIR NO_X emissions limitation.

(a) *Allowance transfer deadline.* The CAIR NO_X Ozone Season allowances are available to be deducted for compliance with a source's CAIR NO_X Ozone Season emissions limitation for a control period in a given calendar year only if the CAIR NO_X Ozone Season allowances:

(1) Were allocated for the control period in the year or a prior year;

(2) Are held in the compliance account as of the allowance transfer deadline for the control period or are transferred into the compliance account by a CAIR NO_X Ozone Season allowance transfer correctly submitted for recordation under § 96.360 by the allowance transfer deadline for the control period; and

(3) Are not necessary for deductions for excess emissions for a prior control period under paragraph (d) of this section.

(b) *Deductions for compliance.* Following the recordation, in accordance with § 96.361, of CAIR NO_X Ozone Season allowance transfers submitted for recordation in a source's compliance account by the allowance transfer deadline for a control period, the Administrator will deduct from the compliance account CAIR NO_X Ozone Season allowances available under paragraph (a) of this section in order to determine whether the source meets the CAIR NO_X Ozone Season emissions limitation for the control period, as follows:

(1) Until the amount of CAIR NO_X Ozone Season allowances deducted equals the number of tons of total nitrogen oxides emissions, determined in accordance with subpart HHHH of this part, from all CAIR NO_X Ozone Season units at the source for the control period; or

(2) If there are insufficient CAIR NO_X Ozone Season allowances to complete the deductions in paragraph (b)(1) of this section, until no more CAIR NO_X Ozone Season allowances available under paragraph (a) of this section remain in the compliance account.

(c)(1) *Identification of CAIR NO_X Ozone Season allowances by serial number.* The CAIR authorized account representative for a source's compliance account may request that specific CAIR NO_X Ozone Season allowances, identified by serial number, in the compliance account be deducted for emissions or excess emissions for a control period in accordance with paragraph (b) or (d) of this section. Such request shall be submitted to the Administrator by the allowance transfer deadline for the control period and include, in a format prescribed by the Administrator, the identification of the CAIR NO_X Ozone Season source and the appropriate serial numbers.

(2) *First-in, first-out.* The Administrator will deduct CAIR NO_X Ozone Season allowances under paragraph (b) or (d) of this section from the source's compliance account, in the absence of an identification or in the case of a partial identification of CAIR NO_X Ozone Season allowances by serial number under paragraph (c)(1) of this section, on a first-in, first-out (FIFO) accounting basis in the following order:

(i) Any CAIR NO_X Ozone Season allowances that were allocated to the units at the source, in the order of recordation; and then

(ii) Any CAIR NO_X Ozone Season allowances that were allocated to any unit and transferred and recorded in the compliance account pursuant to subpart GGGG of this part, in the order of recordation.

(d) *Deductions for excess emissions.* (1) After making the deductions for compliance under paragraph (b) of this section for a control period in a calendar year in which the CAIR NO_X Ozone Season source has excess emissions, the Administrator will deduct from the source's compliance account an amount of CAIR NO_X Ozone Season allowances, allocated for the control period in the immediately following calendar year, equal to 3 times the number of tons of the source's excess emissions.

(2) Any allowance deduction required under paragraph (d)(1) of this section shall not affect the liability of the owners and operators of the CAIR NO_X Ozone Season source or the CAIR NO_X Ozone Season units at the source for any fine, penalty, or assessment, or their obligation to comply with any other remedy, for the same violations, as ordered under the Clean Air Act or applicable State law.

(e) *Recordation of deductions.* The Administrator will record in the appropriate compliance account all deductions from such an account under paragraph (b) or (d) of this section.

(f) *Administrator's action on submissions.* (1) The Administrator may review and conduct independent audits concerning any submission under the CAIR NO_X Ozone Season Trading Program and make appropriate adjustments of the information in the submissions.

(2) The Administrator may deduct CAIR NO_X Ozone Season allowances from or transfer CAIR NO_X Ozone Season allowances to a source's compliance account based on the information in the submissions, as adjusted under paragraph (f)(1) of this section.

§ 96.355 Banking.

(a) CAIR NO_X Ozone Season allowances may be banked for future use or transfer in a compliance account or a general account in accordance with paragraph (b) of this section.

(b) Any CAIR NO_X Ozone Season allowance that is held in a compliance account or a general account will remain in such account unless and until the CAIR NO_X Ozone Season allowance is deducted or transferred under § 96.354, § 96.356, or subpart GG of this part.

§ 96.356 Account error.

The Administrator may, at his or her sole discretion and on his or her own motion, correct any error in any CAIR NO_X Ozone Season Allowance Tracking System account. Within 10 business days of making such correction, the Administrator will notify the CAIR authorized account representative for the account.

§ 96.357 Closing of general accounts.

(a) The CAIR authorized account representative of a general account may submit to the Administrator a request to close the account, which shall include a correctly submitted allowance transfer under § 96.360 for any CAIR NO_X Ozone Season allowances in the account to one or more other CAIR NO_X Ozone Season Allowance Tracking System accounts.

(b) If a general account has no allowance transfers in or out of the account for a 12-month period or longer and does not contain any CAIR NO_X Ozone Season allowances, the Administrator may notify the CAIR authorized account representative for the account that the account will be closed following 20 business days after the notice is sent. The account will be closed after the 20-day period unless, before the end of the 20-day period, the Administrator receives a correctly submitted transfer of CAIR NO_X Ozone Season allowances into the account under § 96.360 or a statement submitted by the CAIR authorized account representative demonstrating to the satisfaction of the Administrator good cause as to why the account should not be closed.

Subpart GGGG—CAIR NO_X Ozone Season Allowance Transfers

§ 96.360 Submission of CAIR NO_X Ozone Season allowance transfers.

A CAIR authorized account representative seeking recordation of a CAIR NO_X Ozone Season allowance transfer shall submit the transfer to the Administrator. To be considered correctly submitted, the CAIR NO_X Ozone Season allowance transfer shall include the following elements, in a format specified by the Administrator:

(a) The account numbers for both the transferor and transferee accounts;

(b) The serial number of each CAIR NO_X Ozone Season allowance that is in the transferor account and is to be transferred; and

(c) The name and signature of the CAIR authorized account representative of the transferor account and the date signed.

§ 96.361 EPA recordation.

(a) Within 5 business days (except as provided in paragraph (b) of this section) of receiving a CAIR NO_X Ozone Season allowance transfer, the Administrator will record a CAIR NO_X Ozone Season allowance transfer by moving each CAIR NO_X Ozone Season allowance from the transferor account to the transferee account as specified by the request, provided that:

(1) The transfer is correctly submitted under § 96.360; and

(2) The transferor account includes each CAIR NO_X Ozone Season allowance identified by serial number in the transfer.

(b) A CAIR NO_X Ozone Season allowance transfer that is submitted for recordation after the allowance transfer deadline for a control period and that includes any CAIR NO_X Ozone Season allowances allocated for any control period before such allowance transfer deadline will not be recorded until after the Administrator completes the deductions under § 96.354 for the control period immediately before such allowance transfer deadline.

(c) Where a CAIR NO_X Ozone Season allowance transfer submitted for recordation fails to meet the requirements of paragraph (a) of this section, the Administrator will not record such transfer.

§ 96.362 Notification.

(a) *Notification of recordation.* Within 5 business days of recordation of a CAIR NO_X Ozone Season allowance transfer under § 96.361, the Administrator will notify the CAIR authorized account representatives of both the transferor and transferee accounts.

(b) *Notification of non-recordation.* Within 10 business days of receipt of a CAIR NO_X Ozone Season allowance transfer that fails to meet the requirements of § 96.361(a), the Administrator will notify the CAIR authorized account representatives of both accounts subject to the transfer of:

(1) A decision not to record the transfer, and

(2) The reasons for such non-recordation.

(c) Nothing in this section shall preclude the submission of a CAIR NO_X Ozone Season allowance transfer for recordation following notification of non-recordation.

Subpart HHHH—Monitoring and Reporting

§ 96.370 General requirements.

The owners and operators, and to the extent applicable, the CAIR designated representative, of a CAIR NO_X Ozone Season unit, shall comply with the monitoring, recordkeeping, and reporting requirements as provided in this subpart and in subpart H of part 75 of this chapter. For purposes of complying with such requirements, the definitions in § 96.302 and in § 72.2 of this chapter shall apply, and the terms ''affected unit,'' ''designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') in part 75 of this chapter shall be deemed to refer to the terms ''CAIR NO_X Ozone Season unit,'' ''CAIR designated representative,'' and ''continuous emission monitoring system'' (or ''CEMS'') respectively, as defined in § 96.302. The owner or operator of a unit that is not a CAIR NO_X Ozone Season unit but that is monitored under § 75.72(b)(2)(ii) of this chapter shall comply with the same monitoring, recordkeeping, and reporting requirements as a CAIR NO_X Ozone Season unit.

(a) *Requirements for installation, certification, and data accounting.* The owner or operator of each CAIR NO_X Ozone Season unit shall:

(1) Install all monitoring systems required under this subpart for monitoring NO_X mass emissions and individual unit heat input (including all systems required to monitor NO_X emission rate, NO_X concentration, stack gas moisture content, stack gas flow rate, CO_2 or O_2 concentration, and fuel flow rate, as applicable, in accordance with §§ 75.71 and 75.72 of this chapter);

(2) Successfully complete all certification tests required under § 96.371 and meet all other requirements of this subpart and part 75 of this chapter applicable to the monitoring systems under paragraph (a)(1) of this section; and

(3) Record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section.

(b) *Compliance deadlines.* The owner or operator shall meet the monitoring system certification and other requirements of paragraphs (a)(1) and (2) of this section on or before the following dates. The owner or operator shall record, report, and quality-assure the data from the monitoring systems under paragraph (a)(1) of this section on and after the following dates.

(1) For the owner or operator of a CAIR NO_X Ozone Season unit that commences commercial operation before July 1, 2007, by May 1, 2008.

(2) For the owner or operator of a CAIR NO_X Ozone Season unit that commences commercial operation on or after July 1, 2007 and that reports on an annual basis under § 96.374(d), by the later of the following dates:

(i) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation; or

(ii) May 1, 2008, if the compliance date under paragraph (b)(2)(i) is before May 1, 2008.

(3) For the owner or operator of a CAIR NO_X Ozone Season unit that commences operation on or after July 1, 2007 and that reports on a control period basis under § 96.374(d)(2)(ii), by the later of the following dates:

(i) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which the unit commences commercial operation; or

(ii) If the compliance date under paragraph (b)(3)(i) of this section is not during a control period, May 1 immediately following the compliance date under paragraph (b)(3)(i) of this section.

(4) For the owner or operator of a CAIR NO_X Ozone Season unit for which construction of a new stack or flue or installation of add-on NO_X emission controls is completed after the applicable deadline under paragraph (b)(1), (2), (6), or (7) of this section and that reports on an annual basis under § 96.374(d), by 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO_X emissions controls.

(5) For the owner or operator of a CAIR NO_X Ozone Season unit for which construction of a new stack or flue or installation of add-on NO_X emission controls is completed after the applicable deadline under paragraph (b)(1), (3), (6), or (7) of this section and that reports on a control period basis under § 96.374(d)(2)(ii), by the later of the following dates:

(i) 90 unit operating days or 180 calendar days, whichever occurs first, after the date on which emissions first exit to the atmosphere through the new stack or flue or add-on NO_X emissions controls; or

(ii) If the compliance date under paragraph (b)(5)(i) of this section is not during a control period, May 1 immediately following the compliance date under paragraph (b)(5)(i) of this section.

(6) Notwithstanding the dates in paragraphs (b)(1), (2), and (3) of this section, for the owner or operator of a unit for which a CAIR NO_X Ozone Season opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart IIII of this part, by the date specified in § 96.384(b).

(7) Notwithstanding the dates in paragraphs (b)(1), (2), and (3) of this section and solely for purposes of § 96.306(c)(2), for the owner or operator of a CAIR NO_X Ozone Season opt-in unit, by the date on which the CAIR NO_X Ozone Season opt-in unit enters the CAIR NO_X Ozone Season Trading Program as provided in § 96.384(g).

(c) *Reporting data.* (1) Except as provided in paragraph (c)(2) of this section, the owner or operator of a CAIR NO_X Ozone Season unit that does not meet the applicable compliance date set forth in paragraph (b) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report maximum potential (or, as appropriate, minimum potential) values for NO_X concentration, NO_X emission rate, stack gas flow rate, stack gas moisture content, fuel flow rate, and any other parameters required to determine NO_X mass emissions and heat input in accordance with § 75.31(b)(2) or (c)(3) of this chapter, section 2.4 of appendix D to part 75 of this chapter, or section 2.5 of appendix E to part 75 of this chapter, as applicable.

(2) The owner or operator of a CAIR NO_X unit that does not meet the applicable compliance date set forth in paragraph (b)(4) of this section for any monitoring system under paragraph (a)(1) of this section shall, for each such monitoring system, determine, record, and report substitute data using the applicable missing data procedures in § 75.74(c)(7) of this chapter or subpart D or subpart H of, or appendix D or appendix E to, part 75 of this chapter, in lieu of the maximum potential (or, as appropriate, minimum potential) values, for a parameter if the owner or operator demonstrates that there is continuity between the data streams for that parameter before and after the construction or installation under paragraph (b)(4) of this section.

(d) *Prohibitions.* (1) No owner or operator of a CAIR NO_X Ozone Season unit shall use any alternative monitoring system, alternative reference method, or any other alternative to any requirement of this subpart without having obtained prior written approval in accordance with § 96.375.

(2) No owner or operator of a CAIR NO_X Ozone Season unit shall operate the unit so as to discharge, or allow to be discharged, NO_X emissions to the atmosphere without accounting for all such emissions in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(3) No owner or operator of a CAIR NO_X Ozone Season unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method, and thereby avoid monitoring and recording NO_X mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing, or maintenance is performed in accordance with the applicable provisions of this subpart and part 75 of this chapter.

(4) No owner or operator of a CAIR NO_X Ozone Season unit shall retire or permanently discontinue use of the continuous emission monitoring system, any component thereof, or any other approved monitoring system under this subpart, except under any one of the following circumstances:

(i) During the period that the unit is covered by an exemption under § 96.305 that is in effect;

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

(iii) The CAIR designated representative submits notification of the date of certification testing of a replacement monitoring system for the retired or discontinued monitoring system in accordance with § 96.371(d)(3)(i).

§ 96.371 Initial certification and recertification procedures.

(a) The owner or operator of a CAIR NO_X Ozone Season unit shall be exempt from the initial certification requirements of this section for a monitoring system under § 96.370(a)(1) if the following conditions are met:

(1) The monitoring system has been previously certified in accordance with part 75 of this chapter; and

(2) The applicable quality-assurance and quality-control requirements of § 75.21 of this chapter and appendix B, appendix D, and appendix E to part 75 of this chapter are fully met for the certified monitoring system described in paragraph (a)(1) of this section.

(b) The recertification provisions of this section shall apply to a monitoring system under § 96.370(a)(1) exempt from initial certification requirements under paragraph (a) of this section.

(c) If the Administrator has previously approved a petition under § 75.17(a) or (b) of this chapter for apportioning the NO_X emission rate measured in a common stack or a petition under § 75.66 of this chapter for an alternative to a requirement in § 75.12, § 75.17, or subpart H of part 75 of this chapter, the CAIR designated representative shall resubmit the petition to the Administrator under § 96.375(a) to determine whether the approval applies under the CAIR NO_X Ozone Season Trading Program.

(d) Except as provided in paragraph (a) of this section, the owner or operator of a CAIR NO_X Ozone Season unit shall comply with the following initial certification and recertification procedures for a continuous monitoring system (i.e., a continuous emission monitoring system and an excepted monitoring system under appendices D and E to part 75 of this chapter) under § 96.370(a)(1). The owner or operator of a unit that qualifies to use the low mass emissions excepted monitoring methodology under § 75.19 of this chapter or that qualifies to use an alternative monitoring system under subpart E of part 75 of this chapter shall comply with the procedures in paragraph (e) or (f) of this section respectively.

(1) *Requirements for initial certification.* The owner or operator shall ensure that each continuous monitoring system under § 96.370(a)(1)(including the automated data acquisition and handling system) successfully completes all of the initial certification testing required under § 75.20 of this chapter by the applicable deadline in § 96.370(b). In addition, whenever the owner or operator installs a monitoring system to meet the requirements of this subpart in a location where no such monitoring system was previously installed, initial certification in accordance with § 75.20 of this chapter is required.

(2) *Requirements for recertification.* Whenever the owner or operator makes a replacement, modification, or change in any certified continuous emission monitoring system under § 96.370(a)(1) that may significantly affect the ability of the system to accurately measure or record NO_X mass emissions or heat input rate or to meet the quality-assurance and quality-control requirements of § 75.21 of this chapter or appendix B to part 75 of this chapter, the owner or operator shall recertify the monitoring system in accordance with § 75.20(b) of this chapter. Furthermore, whenever the owner or operator makes a replacement, modification, or change to the flue gas handling system or the unit's operation that may significantly change the stack flow or concentration profile, the owner or operator shall recertify each continuous emission monitoring system whose accuracy is potentially affected by the change, in accordance with § 75.20(b) of this chapter. Examples of changes to a continuous emission monitoring system that require recertification include: Replacement of the analyzer, complete replacement of an existing continuous emission monitoring system, or change in location or orientation of the sampling probe or site. Any fuel flowmeter systems, and any excepted NO_X monitoring system under appendix E to part 75 of this chapter, under § 96.370(a)(1) are subject to the recertification requirements in § 75.20(g)(6) of this chapter.

(3) *Approval process for initial certification and recertification.* Paragraphs (d)(3)(i) through (iv) of this section apply to both initial certification and recertification of a continuous monitoring system under § 96.370(a)(1). For recertifications, replace the words ''certification'' and ''initial certification'' with the word ''recertification'', replace the word ''certified'' with the word ''recertified,'' and follow the procedures in §§ 75.20(b)(5) and (g)(7) of this chapter in lieu of the procedures in paragraph (d)(3)(v) of this section.

(i) *Notification of certification.* The CAIR designated representative shall submit to the permitting authority, the appropriate EPA Regional Office, and the Administrator written notice of the dates of certification testing, in accordance with § 96.373.

(ii) *Certification application.* The CAIR designated representative shall submit to the permitting authority a certification application for each monitoring system. A complete certification application shall include the information specified in § 75.63 of this chapter.

(iii) *Provisional certification date.* The provisional certification date for a monitoring system shall be determined in accordance with § 75.20(a)(3) of this chapter. A provisionally certified monitoring system may be used under the CAIR NO_X Ozone Season Trading Program for a period not to exceed 120 days after receipt by the permitting authority of the complete certification application for the monitoring system under paragraph (d)(3)(ii) of this section. Data measured and recorded by the provisionally certified monitoring system, in accordance with the requirements of part 75 of this chapter, will be considered valid quality-assured data (retroactive to the date and time of provisional certification), provided that the permitting authority does not invalidate the provisional certification by issuing a notice of disapproval within 120 days of the date of receipt of the complete certification application by the permitting authority.

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

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

(B) *Incomplete application notice.* If the certification application is not complete, then the permitting authority will issue a written notice of incompleteness that sets a reasonable date by which the CAIR designated representative must submit the additional information required to complete the certification application. If the CAIR designated representative does not comply with the notice of incompleteness by the specified date, then the permitting authority may issue a notice of disapproval under paragraph (d)(3)(iv)(C) of this section. The 120-day review period shall not begin before receipt of a complete certification application.

(C) *Disapproval notice.* If the certification application shows that any monitoring system does not meet the performance requirements of part 75 of this chapter or if the certification application is incomplete and the requirement for disapproval under paragraph (d)(3)(iv)(B) of this section is met, then the permitting authority will issue a written notice of disapproval of the certification application. Upon issuance of such notice of disapproval, the provisional certification is invalidated by the permitting authority and the data measured and recorded by each uncertified monitoring system shall not be considered valid quality-assured data beginning with the date and hour of provisional certification (as defined under § 75.20(a)(3) of this chapter). The owner or operator shall follow the procedures for loss of certification in paragraph (d)(3)(v) of this section for each monitoring system that is disapproved for initial certification.

(D) *Audit decertification.* The permitting authority or, for a CAIR NO_X Ozone Season opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a

CAIR opt-in permit is not yet issued or denied under subpart IIII of this part, the Administrator may issue a notice of disapproval of the certification status of a monitor in accordance with § 96.372(b).

(v) *Procedures for loss of certification.* If the permitting authority or the Administrator issues a notice of disapproval of a certification application under paragraph (d)(3)(iv)(C) of this section or a notice of disapproval of certification status under paragraph (d)(3)(iv)(D) of this section, then:

(A) The owner or operator shall substitute the following values, for each disapproved monitoring system, for each hour of unit operation during the period of invalid data specified under § 75.20(a)(4)(iii), § 75.20(g)(7), or § 75.21(e) of this chapter and continuing until the applicable date and hour specified under § 75.20(a)(5)(i) or (g)(7) of this chapter:

(*1*) For a disapproved NO_X emission rate (*i.e.*, NO_X-diluent) system, the maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(*2*) For a disapproved NO_X pollutant concentration monitor and disapproved flow monitor, respectively, the maximum potential concentration of NO_X and the maximum potential flow rate, as defined in sections 2.1.2.1 and 2.1.4.1 of appendix A to part 75 of this chapter.

(*3*) For a disapproved moisture monitoring system and disapproved diluent gas monitoring system, respectively, the minimum potential moisture percentage and either the maximum potential CO_2 concentration or the minimum potential O_2 concentration (as applicable), as defined in sections 2.1.5, 2.1.3.1, and 2.1.3.2 of appendix A to part 75 of this chapter.

(*4*) For a disapproved fuel flowmeter system, the maximum potential fuel flow rate, as defined in section 2.4.2.1 of appendix D to part 75 of this chapter.

(*5*) For a disapproved excepted NO_X monitoring system under appendix E to part 75 of this chapter, the fuel-specific maximum potential NO_X emission rate, as defined in § 72.2 of this chapter.

(B) The CAIR designated representative shall submit a notification of certification retest dates and a new certification application in accordance with paragraphs (d)(3)(i) and (ii) of this section.

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

(e) *Initial certification and recertification procedures for units using the low mass emission excepted methodology under § 75.19 of this chapter.* The owner or operator of a unit qualified to use the low mass emissions (LME) excepted methodology under § 75.19 of this chapter shall meet the applicable certification and recertification requirements in §§ 75.19(a)(2) and 75.20(h) of this chapter. If the owner or operator of such a unit elects to certify a fuel flowmeter system for heat input determination, the owner or operator shall also meet the certification and recertification requirements in § 75.20(g) of this chapter.

(f) *Certification/recertification procedures for alternative monitoring systems.* The CAIR designated representative of each unit for which the owner or operator intends to use an alternative monitoring system approved by the Administrator and, if applicable, the permitting authority under subpart E of part 75 of this chapter shall comply with the applicable notification and application procedures of § 75.20(f) of this chapter.

§ 96.372 Out of control periods.

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

(b) *Audit decertification.* Whenever both an audit of a monitoring system and a review of the initial certification or recertification application reveal that any monitoring system should not have been certified or recertified because it did not meet a particular performance specification or other requirement under § 96.371 or the applicable provisions of part 75 of this chapter, both at the time of the initial certification or recertification application submission and at the time of the audit, the permitting authority or, for a CAIR NO_X Ozone Season opt-in unit or a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart IIII of this part, the Administrator will issue a notice of disapproval of the certification status of such monitoring system. For the purposes of this paragraph, an audit shall be either a field audit or an audit of any information submitted to the permitting authority or the Administrator. By issuing the notice of disapproval, the permitting authority or the Administrator revokes prospectively the certification status of the monitoring system. The data measured and recorded by the monitoring system shall not be considered valid quality-assured data from the date of issuance of the notification of the revoked certification status until the date and time that the owner or operator completes subsequently approved initial certification or recertification tests for the monitoring system. The owner or operator shall follow the applicable initial certification or recertification procedures in § 96.371 for each disapproved monitoring system.

§ 96.373 Notifications.

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

§ 96.374 Recordkeeping and reporting.

(a) *General provisions.* The CAIR designated representative shall comply with all recordkeeping and reporting requirements in this section, the applicable recordkeeping and reporting requirements under § 75.73 of this chapter, and the requirements of § 96.310(e)(1).

(b) *Monitoring plans.* The owner or operator of a CAIR NO_X Ozone Season unit shall comply with requirements of § 75.73(c) and (e) of this chapter and, for a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under subpart IIII of this part, §§ 96.383 and 96.384(a).

(c) *Certification applications.* The CAIR designated representative shall submit an application to the permitting authority within 45 days after completing all initial certification or recertification tests required under § 96.371, including the information required under § 75.63 of this chapter.

(d) *Quarterly reports.* The CAIR designated representative shall submit quarterly reports, as follows:

(1) If the CAIR NO_X Ozone Season unit is subject to an Acid Rain emissions limitation or a CAIR NO_X emissions limitation or if the owner or operator of such unit chooses to report on an annual basis under this subpart, the CAIR designated representative shall meet the requirements of subpart H of part 75 of this chapter (concerning monitoring of NO_X mass emissions) for

such unit for the entire year and shall report the NO_X mass emissions data and heat input data for such unit, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(i) For a unit that commences commercial operation before July 1, 2007, the calendar quarter covering May 1, 2008 through June 30, 2008; or

(ii) For a unit that commences commercial operation on or after July 1, 2007, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 96.370(b), unless that quarter is the third or fourth quarter of 2007, in which case reporting shall commence in the quarter covering May 1, 2008 through June 30, 2008.

(2) If the CAIR NO_X Ozone Season unit is not subject to an Acid Rain emissions limitation or a CAIR NO_X emissions limitation, then the CAIR designated representative shall either:

(i) Meet the requirements of subpart H of part 75 (concerning monitoring of NO_X mass emissions) for such unit for the entire year and report the NO_X mass emissions data and heat input data for such unit in accordance with paragraph (d)(1) of this section; or

(ii) Meet the requirements of subpart H of part 75 for the control period (including the requirements in § 75.74(c) of this chapter) and report NO_X mass emissions data and heat input data (including the data described in § 75.74(c)(6) of this chapter) for such unit only for the control period of each year and report, in an electronic quarterly report in a format prescribed by the Administrator, for each calendar quarter beginning with:

(A) For a unit that commences commercial operation before July 1, 2007, the calendar quarter covering May 1, 2008 through June 30, 2008;

(B) For a unit that commences commercial operation on or after July 1, 2007, the calendar quarter corresponding to the earlier of the date of provisional certification or the applicable deadline for initial certification under § 96.370(b), unless that date is not during a control period, in which case reporting shall commence in the quarter that includes May 1 through June 30 of the first control period after such date.

(2) The CAIR designated representative shall submit each quarterly report to the Administrator within 30 days following the end of the calendar quarter covered by the report. Quarterly reports shall be submitted in the manner specified in § 75.73(f) of this chapter.

(3) For CAIR NO_X Ozone Season units that are also subject to an Acid Rain emissions limitation or the CAIR NO_X Annual Trading Program or CAIR SO_2 Trading Program, quarterly reports shall include the applicable data and information required by subparts F through H of part 75 of this chapter as applicable, in addition to the NO_X mass emission data, heat input data, and other information required by this subpart.

(e) *Compliance certification.* The CAIR designated representative shall submit to the Administrator a compliance certification (in a format prescribed by the Administrator) in support of each quarterly report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall state that:

(1) The monitoring data submitted were recorded in accordance with the applicable requirements of this subpart and part 75 of this chapter, including the quality assurance procedures and specifications;

(2) For a unit with add-on NO_X emission controls and for all hours where NO_X data are substituted in accordance with § 75.34(a)(1) of this chapter, the add-on emission controls were operating within the range of parameters listed in the quality assurance/quality control program under appendix B to part 75 of this chapter and the substitute data values do not systematically underestimate NO_X emissions; and

(3) For a unit that is reporting on a control period basis under paragraph (d)(2)(ii) of this section, the NO_X emission rate and NO_X concentration values substituted for missing data under subpart D of part 75 of this chapter are calculated using only values from a control period and do not systematically underestimate NO_X emissions.

§ 96.375 Petitions.

(a) Except as provided in paragraph (b)(2) of this section, the CAIR designated representative of a CAIR NO_X Ozone Season unit that is subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by the Administrator, in consultation with the permitting authority.

(b)(1) The CAIR designated representative of a CAIR NO_X Ozone Season unit that is not subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to any requirement of this subpart. Application of an alternative to any requirement of this subpart is in accordance with this subpart only to the extent that the petition is approved in writing by both the permitting authority and the Administrator.

(2) The CAIR designated representative of a CAIR NO_X Ozone Season unit that is subject to an Acid Rain emissions limitation may submit a petition under § 75.66 of this chapter to the permitting authority and the Administrator requesting approval to apply an alternative to a requirement concerning any additional continuous emission monitoring system required under § 75.72 of this chapter. Application of an alternative to any such requirement is in accordance with this subpart only to the extent that the petition is approved in writing by both the permitting authority and the Administrator.

§ 96.376 Additional requirements to provide heat input data.

The owner or operator of a CAIR NO_X Ozone Season unit that monitors and reports NO_X mass emissions using a NO_X concentration system and a flow system shall also monitor and report heat input rate at the unit level using the procedures set forth in part 75 of this chapter.

Subpart IIII—CAIR NO_X Ozone Season Opt-in Units

§ 96.380 Applicability.

A CAIR NO_X Ozone Season opt-in unit must be a unit that:

(a) Is located in the State;

(b) Is not a CAIR NO_X Ozone Season unit under § 96.304 and is not covered by a retired unit exemption under § 96.305 that is in effect;

(c) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(d) Has or is required or qualified to have a title V operating permit or other federally enforceable permit; and

(e) Vents all of its emissions to a stack and can meet the monitoring, recordkeeping, and reporting requirements of subpart HHHH of this part.

§ 96.381 General.

(a) Except as otherwise provided in §§ 96.301 through 96.304, §§ 96.306

through 96.308, and subparts BBBB and CCCC and subparts FFFF through HHHH of this part, a CAIR NO_X Ozone Season opt-in unit shall be treated as a CAIR NO_X Ozone Season unit for purposes of applying such sections and subparts of this part.

(b) Solely for purposes of applying, as provided in this subpart, the requirements of subpart HHHH of this part to a unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, such unit shall be treated as a CAIR NO_X Ozone Season unit before issuance of a CAIR opt-in permit for such unit.

§ 96.382 CAIR designated representative.

Any CAIR NO_X Ozone Season opt-in unit, and any unit for which a CAIR opt-in permit application is submitted and not withdrawn and a CAIR opt-in permit is not yet issued or denied under this subpart, located at the same source as one or more CAIR NO_X Ozone Season units shall have the same CAIR designated representative and alternate CAIR designated representative as such CAIR NO_X Ozone Season units.

§ 96.383 Applying for CAIR opt-in permit.

(a) *Applying for initial CAIR opt-in permit.* The CAIR designated representative of a unit meeting the requirements for a CAIR NO_X Ozone Season opt-in unit in § 96.380 may apply for an initial CAIR opt-in permit at any time, except as provided under § 96.386 (f) and (g), and, in order to apply, must submit the following:

(1) A complete CAIR permit application under § 96.322;

(2) A certification, in a format specified by the permitting authority, that the unit:

(i) Is not a CAIR NO_X Ozone Season unit under § 96.304 and is not covered by a retired unit exemption under § 96.305 that is in effect;

(ii) Is not covered by a retired unit exemption under § 72.8 of this chapter that is in effect;

(iii) Vents all of its emissions to a stack; and

(iv) Has documented heat input for more than 876 hours during the 6 months immediately preceding submission of the CAIR permit application under § 96.322;

(3) A monitoring plan in accordance with subpart HHHH of this part;

(4) A complete certificate of representation under § 96.313 consistent with § 96.382, if no CAIR designated representative has been previously designated for the source that includes the unit; and

(5) A statement, in a format specified by the permitting authority, whether the CAIR designated representative requests that the unit be allocated CAIR NO_X Ozone Season allowances under § 96.388(c) (subject to the conditions in §§ 96.384(h) and 96.386(g)).

(b) *Duty to reapply.* (1) The CAIR designated representative of a CAIR NO_X Ozone Season opt-in unit shall submit a complete CAIR permit application under § 96.322 to renew the CAIR opt-in unit permit in accordance with the permitting authority's regulations for title V operating permits, or the permitting authority's regulations for other federally enforceable permits if applicable, addressing permit renewal.

(2) Unless the permitting authority issues a notification of acceptance of withdrawal of the CAIR opt-in unit from the CAIR NO_X Annual Trading Program in accordance with § 96.186 or the unit becomes a CAIR NO_X unit under § 96.304, the CAIR NO_X opt-in unit shall remain subject to the requirements for a CAIR NO_X opt-in unit, even if the CAIR designated representative for the CAIR NO_X opt-in unit fails to submit a CAIR permit application that is required for renewal of the CAIR opt-in permit under paragraph (b)(1) of this section.

§ 96.384 Opt-in process.

The permitting authority will issue or deny a CAIR opt-in permit for a unit for which an initial application for a CAIR opt-in permit under § 96.383 is submitted in accordance with the following:

(a) *Interim review of monitoring plan.* The permitting authority and the Administrator will determine, on an interim basis, the sufficiency of the monitoring plan accompanying the initial application for a CAIR opt-in permit under § 96.383. A monitoring plan is sufficient, for purposes of interim review, if the plan appears to contain information demonstrating that the NO_X emissions rate and heat input of the unit and all other applicable parameters are monitored and reported in accordance with subpart HHHH of this part. A determination of sufficiency shall not be construed as acceptance or approval of the monitoring plan.

(b) *Monitoring and reporting.* (1)(i) If the permitting authority and the Administrator determine that the monitoring plan is sufficient under paragraph (a) of this section, the owner or operator shall monitor and report the NO_X emissions rate and the heat input of the unit emissions rate and the heat input of the unit and all other applicable parameters, in accordance with subpart HHHH of this part, starting on the date of certification of the appropriate monitoring systems under subpart HHHH of this part and continuing until a CAIR opt-in permit is denied under § 96.384(f) or, if a CAIR opt-in permit is issued, the date and time when the unit is withdrawn from the CAIR NO_X Ozone Season Trading Program in accordance with § 96.386.

(ii) The monitoring and reporting under paragraph (b)(1)(i) of this section shall include the entire control period immediately before the date on which the unit enters the CAIR NO_X Ozone Season Trading Program under § 96.384(g), during which period monitoring system availability must not be less than 90 percent under subpart HHHH of this part and the unit must be in full compliance with any applicable State or Federal emissions or emissions-related requirements.

(2) To the extent the NO_X emissions rate and the heat input of the unit are monitored and reported in accordance with subpart HHHH of this part for one or more control periods, in addition to the control period under paragraph (b)(1)(ii) of this section, during which control periods monitoring system availability is not less than 90 percent under subpart HHHH of this part and the unit is in full compliance with any applicable State or Federal emissions or emissions-related requirements and which control periods begin not more than 3 years before the unit enters the CAIR NO_X Ozone Season Trading Program under § 96.384(g), such information shall be used as provided in paragraphs (c) and (d) of this section.

(c) *Baseline heat input.* The unit's baseline heat rate shall equal:

(1) If the unit's NO_X emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit's total heat input (in mmBtu) for the control period; or

(2) If the unit's NO_X emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, the average of the amounts of the unit's total heat input (in mmBtu) for the control period under paragraph (b)(1)(ii) of this section and the control periods under paragraph (b)(2) of this section.

(d) *Baseline NO_X emission rate.* The unit's baseline NO_X emission rate shall equal:

(1) If the unit's NO_X emissions rate and heat input are monitored and reported for only one control period, in accordance with paragraph (b)(1) of this section, the unit's NO_X emissions rate (in lb/mmBtu) for the control period;

(2) If the unit's NO_X emissions rate and heat input are monitored and

reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit does not have add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emissions rate (in lb/mmBtu) for the control period under paragraph (b)(1)(ii) of this section and the control periods under paragraph (b)(2) of this section; or

(3) If the unit's NO_X emissions rate and heat input are monitored and reported for more than one control period, in accordance with paragraphs (b)(1) and (2) of this section, and the unit has add-on NO_X emission controls during any such control periods, the average of the amounts of the unit's NO_X emissions rate (in lb/mmBtu) for such control period during which the unit has add-on NO_X emission controls.

(e) *Issuance of CAIR opt-in permit.* After calculating the baseline heat input and the baseline NO_X emissions rate for the unit under paragraphs (c) and (d) of this section and if the permitting authority determines that the CAIR designated representative shows that the unit meets the requirements for a CAIR NO_X Ozone Season opt-in unit in § 96.380 and meets the elements certified in § 96.383(a)(2), the permitting authority will issue a CAIR opt-in permit. The permitting authority will provide a copy of the CAIR opt-in permit to the Administrator, who will then establish a compliance account for the source that includes the CAIR NO_X Ozone Season opt-in unit unless the source already has a compliance account.

(f) *Issuance of denial of CAIR opt-in permit.* Notwithstanding paragraphs (a) through (e) of this section, if at any time before issuance of a CAIR opt-in permit for the unit, the permitting authority determines that the CAIR designated representative fails to show that the unit meets the requirements for a CAIR NO_X Ozone Season opt-in unit in § 96.380 or meets the elements certified in § 96.383(a)(2), the permitting authority will issue a denial of a CAIR opt-in permit for the unit.

(g) *Date of entry into CAIR NO_X Ozone Season Trading Program.* A unit for which an initial CAIR opt-in permit is issued by the permitting authority shall become a CAIR NO_X Ozone Season opt-in unit, and a CAIR NO_X Ozone Season unit, as of the later of May 1, 2009 or May 1 of the first control period during which such CAIR opt-in permit is issued.

(h) *Repowered CAIR NO_X Ozone Season opt-in unit.* (1) If CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR NO_X Ozone Season opt-in unit of CAIR NO_X Ozone Season allowances under § 96.388(c) and such unit is repowered after its date of entry into the CAIR NO_X Ozone Season Trading Program under paragraph (g) of this section, the repowered unit shall be treated as a CAIR NO_X Ozone Season opt-in unit replacing the original CAIR NO_X Ozone Season opt-in unit, as of the date of start-up of the repowered unit's combustion chamber.

(2) Notwithstanding paragraphs (c) and (d) of this section, as of the date of start-up under paragraph (h)(1) of this section, the repowered unit shall be deemed to have the same date of commencement of operation, date of commencement of commercial operation, baseline heat input, and baseline NO_X emission rate as the original CAIR NO_X Ozone Season opt-in unit, and the original CAIR NO_X Ozone Season opt-in unit shall no longer be treated as a CAIR opt-in unit or a CAIR NO_X Ozone Season unit.

§ 96.385 CAIR opt-in permit contents.

(a) Each CAIR opt-in permit will contain:

(1) All elements required for a complete CAIR permit application under § 96.322;

(2) The certification in § 96.383(a)(2);

(3) The unit's baseline heat input under § 96.384(c);

(4) The unit's baseline NO_X emission rate under § 96.384(d);

(5) A statement whether the unit is to be allocated CAIR NO_X Ozone Season allowances under § 96.388(c) (subject to the conditions in §§ 96.384(h) and 96.386(g));

(6) A statement that the unit may withdraw from the CAIR NO_X Ozone Season Trading Program only in accordance with § 96.386; and

(7) A statement that the unit is subject to, and the owners and operators of the unit must comply with, the requirements of § 96.387.

(b) Each CAIR opt-in permit is deemed to incorporate automatically the definitions of terms under § 96.302 and, upon recordation by the Administrator under subpart FFFF or GGGG of this part or this subpart, every allocation, transfer, or deduction of CAIR NO_X Ozone Season allowances to or from the compliance account of the source that includes a CAIR NO_X Ozone Season opt-in unit covered by the CAIR opt-in permit.

§ 96.386 Withdrawal from CAIR NO_X Ozone Season Trading Program.

Except as provided under paragraph (g) of this section, a CAIR NO_X Ozone Season opt-in unit may withdraw from the CAIR NO_X Ozone Season Trading Program, but only if the permitting authority issues a notification to the CAIR designated representative of the CAIR NO_X Ozone Season opt-in unit of the acceptance of the withdrawal of the CAIR NO_X Ozone Season opt-in unit in accordance with paragraph (d) of this section.

(a) *Requesting withdrawal.* In order to withdraw a CAIR opt-in unit from the CAIR NO_X Ozone Season Trading Program, the CAIR designated representative of the CAIR NO_X Ozone Season opt-in unit shall submit to the permitting authority a request to withdraw effective as of midnight of September 30 of a specified calendar year, which date must be at least 4 years after September 30 of the year of entry into the CAIR NO_X Ozone Season Trading Program under § 96.384(g). The request must be submitted no later than 90 days before the requested effective date of withdrawal.

(b) *Conditions for withdrawal.* Before a CAIR NO_X Ozone Season opt-in unit covered by a request under paragraph (a) of this section may withdraw from the CAIR NO_X Ozone Season Trading Program and the CAIR opt-in permit may be terminated under paragraph (e) of this section, the following conditions must be met:

(1) For the control period ending on the date on which the withdrawal is to be effective, the source that includes the CAIR NO_X Ozone Season opt-in unit must meet the requirement to hold CAIR NO_X Ozone Season allowances under § 96.306(c) and cannot have any excess emissions.

(2) After the requirement for withdrawal under paragraph (b)(1) of this section is met, the Administrator will deduct from the compliance account of the source that includes the CAIR NO_X Ozone Season opt-in unit CAIR NO_X Ozone Season allowances equal in number to and allocated for the same or a prior control period as any CAIR NO_X Ozone Season allowances allocated to the CAIR NO_X Ozone Season opt-in unit under § 96.388 for any control period for which the withdrawal is to be effective. If there are no remaining CAIR NO_X Ozone Season units at the source, the Administrator will close the compliance account, and the owners and operators of the CAIR NO_X Ozone Season opt-in unit may submit a CAIR NO_X Ozone Season allowance transfer for any remaining CAIR NO_X Ozone Season allowances to another CAIR NO_X Ozone Season Allowance Tracking System in accordance with subpart GGGG of this part.

(c) *Notification.* (1) After the requirements for withdrawal under paragraphs (a) and (b) of this section are met (including deduction of the full amount of CAIR NO_X Ozone Season allowances required), the permitting authority will issue a notification to the CAIR designated representative of the CAIR NO_X Ozone Season opt-in unit of the acceptance of the withdrawal of the CAIR NO_X Ozone Season opt-in unit as of midnight on September 30 of the calendar year for which the withdrawal was requested.

(2) If the requirements for withdrawal under paragraphs (a) and (b) of this section are not met, the permitting authority will issue a notification to the CAIR designated representative of the CAIR NO_X Ozone Season opt-in unit that the CAIR NO_X Ozone Season opt-in unit's request to withdraw is denied. Such CAIR NO_X opt-in unit shall continue to be a CAIR NO_X Ozone Season opt-in unit.

(d) *Permit amendment.* After the permitting authority issues a notification under paragraph (c)(1) of this section that the requirements for withdrawal have been met, the permitting authority will revise the CAIR permit covering the CAIR NO_X Ozone Season opt-in unit to terminate the CAIR opt-in permit for such unit as of the effective date specified under paragraph (c)(1) of this section. The unit shall continue to be a CAIR NO_X Ozone Season opt-in unit until the effective date of the termination and shall comply with all requirements under the CAIR NO_X Ozone Season Trading Program concerning any control periods for which the unit is a CAIR NO_X Ozone Season opt-in unit, even if such requirements arise or must be complied with after the withdrawal takes effect.

(e) *Reapplication upon failure to meet conditions of withdrawal.* If the permitting authority denies the CAIR NO_X Ozone Season opt-in unit's request to withdraw, the CAIR designated representative may submit another request to withdraw in accordance with paragraphs (a) and (b) of this section.

(f) *Ability to reapply to the CAIR NO_X Ozone Season Trading Program.* Once a CAIR NO_X Ozone Season opt-in unit withdraws from the CAIR NO_X Ozone Season Trading Program and its CAIR opt-in permit is terminated under this section, the CAIR designated representative may not submit another application for a CAIR opt-in permit under § 96.383 for such CAIR NO_X Ozone Season opt-in unit before the date that is 4 years after the date on which the withdrawal became effective. Such new application for a CAIR opt-in permit will be treated as an initial application for a CAIR opt-in permit under § 96.384.

(g) *Inability to withdraw.* Notwithstanding paragraphs (a) through (f) of this section, a CAIR NO_X Ozone Season opt-in unit shall not be eligible to withdraw from the CAIR NO_X Ozone Season Trading Program if the CAIR designated representative of the CAIR NO_X opt-in unit requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to the CAIR NO_X Ozone Season opt-in unit of CAIR NO_X Ozone Season allowances under § 96.388(c).

§ 96.387 Change in regulatory status.

(a) *Notification.* If a CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304, then the CAIR designated representative shall notify in writing the permitting authority and the Administrator of such change in the CAIR NO_X Ozone Season opt-in unit's regulatory status, within 30 days of such change.

(b) *Permitting authority's and Administrator's actions.* (1) If a CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304, the permitting authority will revise the CAIR NO_X Ozone Season opt-in unit's CAIR opt-in permit to meet the requirements of a CAIR permit under § 96.323 as of the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304.

(2)(i) The Administrator will deduct from the compliance account of the source that includes the CAIR NO_X Ozone Season opt-in unit that becomes a CAIR NO_X Ozone Season unit under § 96.304, CAIR NO_X Ozone Season allowances equal in number to and allocated for the same or a prior control period as:

(A) Any CAIR NO_X Ozone Season allowances allocated to the CAIR NO_X Ozone Season opt-in unit under § 96.388 for any control period after the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304; and

(B) If the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304 is not September 30, the CAIR NO_X Ozone Season allowances allocated to the CAIR NO_X Ozone Season opt-in unit under § 96.388 for the control period that includes the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304, multiplied by the ratio of the number of days, in the control period, starting with the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304 divided by the total number of days in the control period and rounded to the nearest whole allowance as appropriate.

(ii) The CAIR designated representative shall ensure that the compliance account of the source that includes the CAIR NO_X Ozone Season unit that becomes a CAIR NO_X Ozone Season unit under § 96.304 contains the CAIR NO_X Ozone Season allowances necessary for completion of the deduction under paragraph (b)(2)(i) of this section.

(3)(i) For every control period after the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304, the CAIR NO_X Ozone Season opt-in unit will be treated, solely for purposes of CAIR NO_X Ozone Season allowance allocations under § 96.342, as a unit that commences operation on the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304 and will be allocated CAIR NO_X Ozone Season allowances under § 96.342.

(ii) Notwithstanding paragraph (b)(3)(i) of this section, if the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304 is not May 1, the following number of CAIR NO_X Ozone Season allowances will be allocated to the CAIR NO_X Ozone Season opt-in unit (as a CAIR NO_X Ozone Season unit) under § 96.342 for the control period that includes the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304:

(A) The number of CAIR NO_X Ozone Season allowances otherwise allocated to the CAIR NO_X Ozone Season opt-in unit (as a CAIR NO_X Ozone Season unit) under § 96.342 for the control period multiplied by;

(B) The ratio of the number of days, in the control period, starting with the date on which the CAIR NO_X Ozone Season opt-in unit becomes a CAIR NO_X Ozone Season unit under § 96.304, divided by the total number of days in the control period; and

(C) Rounded to the nearest whole allowance as appropriate.

§ 96.388 NO_X allowance allocations to CAIR NO_X Ozone Season opt-in units.

(a) *Timing requirements.* (1) When the CAIR opt-in permit is issued under § 96.384(e), the permitting authority will allocate CAIR NO_X Ozone Season allowances to the CAIR NO_X Ozone Season opt-in unit, and submit to the Administrator the allocation for the control period in which a CAIR NO_X Ozone Season opt-in unit enters the

CAIR NO_X Ozone Season Trading Program under § 96.384(g), in accordance with paragraph (b) or (c) of this section.

(2) By no later than July 31 of the control period in which a CAIR opt-in unit enters the CAIR NO_X Ozone Season Trading Program under § 96.384(g) and July 31 of each year thereafter, the permitting authority will allocate CAIR NO_X Ozone Season allowances to the CAIR NO_X Ozone Season opt-in unit, and submit to the Administrator the allocation for the control period that includes such submission deadline and in which the unit is a CAIR NO_X opt-in unit, in accordance with paragraph (b)or (c) of this section.

(b) *Calculation of allocation.* For each control period for which a CAIR NO_X Ozone Season opt-in unit is to be allocated CAIR NO_X Ozone Season allowances, the permitting authority will allocate in accordance with the following procedures:

(1) The heat input (in mmBtu) used for calculating the CAIR NO_X Ozone Season allowance allocation will be the lesser of:

(i) The CAIR NO_X Ozone Season opt-in unit's baseline heat input determined under § 96.384(c); or

(ii) The CAIR NO_X Ozone Season opt-in unit's heat input, as determined in accordance with subpart HHHH of this part, for the immediately prior control period, except when the allocation is being calculated for the control period in which the CAIR NO_X Ozone Season opt-in unit enters the CAIR NO_X Ozone Season Trading Program under § 96.384(g).

(2) The NO_X emission rate (in lb/mmBtu) used for calculating CAIR NO_X Ozone Season allowance allocations will be the lesser of:

(i) The CAIR NO_X Ozone Season opt-in unit's baseline NO_X emissions rate (in lb/mmBtu) determined under § 96.384(d) and multiplied by 70 percent; or

(ii) The most stringent State or Federal NO_X emissions limitation applicable to the CAIR NO_X Ozone Season opt-in unit at any time during the control period for which CAIR NO_X Ozone Season allowances are to be allocated.

(3) The permitting authority will allocate CAIR NO_X Ozone Season allowances to the CAIR NO_X Ozone Season opt-in unit in an amount equaling the heat input under paragraph (b)(1) of this section, multiplied by the NO_X emission rate under paragraph (b)(2) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(c) Notwithstanding paragraph (b) of this section and if the CAIR designated representative requests, and the permitting authority issues a CAIR opt-in permit providing for, allocation to a CAIR NO_X Ozone Season opt-in unit of CAIR NO_X Ozone Season allowances under this paragraph (subject to the conditions in §§ 96.384(h) and 96.386(g)), the permitting authority will allocate to the CAIR NO_X Ozone Season opt-in unit as follows:

(1) For each control period in 2009 through 2014 for which the CAIR NO_X Ozone Season opt-in unit is to be allocated CAIR NO_X Ozone Season allowances,

(i) The heat input (in mmBtu) used for calculating CAIR NO_X Ozone Season allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The NO_X emission rate (in lb/mmBtu) used for calculating CAIR NO_X Ozone Season allowance allocations will be the lesser of:

(A) The CAIR NO_X Ozone Season opt-in unit's baseline NO_X emissions rate (in lb/mmBtu) determined under § 96.384(d); or

(B) The most stringent State or Federal NO_X emissions limitation applicable to the CAIR NO_X Ozone Season opt-in unit at any time during the control period in which the CAIR NO_X Ozone Season opt-in unit enters the CAIR NO_X Ozone Season Trading Program under § 96.384(g).

(iii) The permitting authority will allocate CAIR NO_X Ozone Season allowances to the CAIR NO_X Ozone Season opt-in unit in an amount equaling the heat input under paragraph (c)(1)(i) of this section, multiplied by the NO_X emission rate under paragraph (c)(1)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(2) For each control period in 2015 and thereafter for which the CAIR NO_X Ozone Season opt-in unit is to be allocated CAIR NO_X Ozone Season allowances,

(i) The heat input (in mmBtu) used for calculating the CAIR NO_X Ozone Season allowance allocations will be determined as described in paragraph (b)(1) of this section.

(ii) The NO_X emission rate (in lb/mmBtu) used for calculating the CAIR NO_X Ozone Season allowance allocation will be the lesser of:

(A) 0.15 lb/mmBtu;

(B) The CAIR NO_X Ozone Season opt-in unit's baseline NO_X emissions rate (in lb/mmBtu) determined under § 96.384(d); or

(C) The most stringent State or Federal NO_X emissions limitation applicable to the CAIR NO_X Ozone Season opt-in unit at any time during the control period for which CAIR NO_X Ozone Season allowances are to be allocated.

(iii) The permitting authority will allocate CAIR NO_X Ozone Season allowances to the CAIR NO_X Ozone Season opt-in unit in an amount equaling the heat input under paragraph (c)(2)(i) of this section, multiplied by the NO_X emission rate under paragraph (c)(2)(ii) of this section, divided by 2,000 lb/ton, and rounded to the nearest whole allowance as appropriate.

(d) *Recordation.* (1) The Administrator will record, in the compliance account of the source that includes the CAIR NO_X Ozone Season opt-in unit, the CAIR NO_X Ozone Season allowances allocated by the permitting authority to the CAIR NO_X Ozone Season opt-in unit under paragraph (a)(1) of this section.

(2) By September 1, of the control period in which a CAIR opt-in unit enters the CAIR NO_X Ozone Season Trading Program under § 96.384(g), and September 1 of each year thereafter, the Administrator will record, in the compliance account of the source that includes the CAIR NO_X Ozone Season opt-in unit, the CAIR NO_X Ozone Season allowances allocated by the permitting authority to the CAIR NO_X Ozone Season opt-in unit under paragraph (a)(2) of this section.

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