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ORIGINAL

GULF POWER
A SOUTHERN COMPANY

March 29, 2007

Ms. Ann Cole, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee FL 32399-0850

Dear Ms. Cole:

Re: Docket No. 070007-EI

Enclosed are an original and fifteen copies of Gulf Power's Supplemental Petition of Gulf Power Company Regarding Its CAIR/CAMR/CAVR Environmental Compliance Program Pursuant to Stipulation of Parties, and Exhibit A to this supplemental petition entitled "Gulf Power Company Environmental Compliance Program for the Clean Air Interstate Rule, Clean Air Mercury Rule, and Clean Air Visibility Rule", to be filed in the above referenced docket.

A 3.5 inch double sided, double density diskette containing the Petition in Microsoft Word for Windows format as prepared on an NT computer has been sent to you under separate cover.

Sincerely,

Susan D. Ritenour
bh

CMP ____
COM 5
CTR ____
ECR ____
GCL 1
OPC ____
RCA 2
SCR ____
SGA ____
SEC ____
OTH ____

bh

Enclosures

cc: Squire, Sanders & Dempsey, LLP
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Beggs & Lane
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: **Environmental Cost Recovery Clause**)))

Docket No.: **070007-EI**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that this filing is being made by U. S. Mail to the following, except filing to those marked with an asterisk will be by Federal Express Mail, this 29th day of March, 2007:

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 070007-EI

GULF POWER COMPANY
Environmental Compliance Program
for the
Clean Air Interstate Rule
Clean Air Mercury Rule
Clean Air Visibility Rule

Date of Filing: March 29, 2007

GULF POWER

A SOUTHERN COMPANY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Environmental Cost	)	Docket No. 070007-EI
Recovery Clause.	)	Filed: March 29, 2007
______________________________	)	

SUPPLEMENTAL PETITION OF GULF POWER COMPANY REGARDING ITS CAIR/CAMR/CAVR ENVIRONMENTAL COMPLIANCE PROGRAM PURSUANT TO STIPULATION OF PARTIES

Notices and communications with respect to this petition and docket should be addressed to:

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Gulf Power Company, ("Gulf Power", "Gulf", or "the "Company"), by and through its undersigned attorneys, hereby petitions the Florida Public Service Commission ("Commission") for approval of the Company's plan to achieve and maintain compliance with the Clean Air Interstate Rule ("CAIR"), the Clean Air Mercury Rule ("CAMR") and the Clean Air Visibility Rule ("CAVR")[1] as set forth in Gulf's CAIR/CAMR/CAVR Environmental Compliance Program. In support of this request for the Commission's review and approval of the reasonableness and prudence of Gulf's compliance plan, the Company states:

1. This supplemental petition is made by the Company to comply with its obligations under the terms of a stipulation negotiated between Gulf and the Office of Public Counsel

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[1]In its previous filings, Gulf advised the Commission that the strategy chosen by the Company under its CAIR/CAMR environmental compliance program would also meet the Best Available Retrofit Technology ("BART") under the Regional Haze Rule, which is now known as the Clean Air Visibility Rule ("CAVR"). The name of Gulf's compliance program has been modified to explicitly recognize that it addresses the requirements of all three rules -- CAIR, CAMR and CAVR.

and approved by the Commission as set forth at page 9 of Order No. PSC-06-0972-FOF-EI issued November 22, 2006, in Docket No. 060007-EI. The full text of the stipulation, as approved by the Commission, is set forth below:

> We approve the following stipulation regarding Gulf's request for recovery of compliance costs relating to the Clean Air Interstate Rule and the Clean Air Mercury Rule as a project that qualifies for recovery through the ECRC:
>
> Gulf's reasonable and necessary, prudently incurred costs for compliance with the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) are appropriate for recovery through the ECRC as provided for in F.S. 366.8255 and past Commission orders implementing the ECRC. The costs impacting 2007 ECRC revenue requirements as outlined in Gulf's petition, testimony and exhibits are appropriately incorporated in the Company's cost recovery factors for 2007 which have been submitted for approval in this proceeding, subject to the normal evaluation and true-up process that takes place in the ongoing ECRC proceedings. Given the magnitude and the scope of Gulf's ongoing CAIR/CAMR Compliance Program, Gulf agrees to make a supplementary filing in the ECRC docket during the first quarter of 2007 that will identify the timing and current estimates of costs for specific projects planned by the Company in order to comply with CAIR/CAMR requirements along with information regarding the relative value of the planned projects compared to other viable compliance alternatives, if any. This supplemental filing will include a description of the evaluation process used and the results of that process that lead Gulf to conclude that the chosen control technology is both cost effective and that the affected generating units remain economically viable as a source of energy to Gulf's retail customers with the addition of the controls. The parties to the ECRC (including the Commission Staff) will be allowed to submit normal requests for discovery in connection with the supplemental filing in order to determine whether there is any objection to any components of the CAIR/CAMR program with regard to the reasonableness or prudence of the proposed action. If there are any objections, the objecting party shall give notice to the Company before the end of the second quarter of 2007 such that testimony and exhibits addressing the resulting issue(s) can be filed in the normal time frame for the 2007 ECRC hearing and the issue(s) can be resolved by the Commission in the normal course of the ongoing ECRC proceedings. The deadlines set forth in this stipulation can be extended for good cause by mutual agreement of the parties. In the event the parties are unable to reach an agreement regarding a request for extension of a deadline, the request may be presented to the prehearing officer for resolution by motion showing good cause why the deadline should be extended.

2. Exhibit A to this supplemental petition is a document entitled "Gulf Power Company Environmental Compliance Program for the Clean Air Interstate Rule, Clean Air Mercury Rule and Clean Air Visibility Rule" ("Compliance Plan"). The contents of Exhibit A, which is an essential part of this supplemental petition and is incorporated herein by reference, will be discussed in further detail in paragraphs to follow.

BACKGROUND

3. On July 26, 2005, in order to comply with certain procedural requirements established by the Commission for the Environmental Cost Recovery Clause ("ECRC"), Gulf Power filed its Preliminary List of New Projects for Cost Recovery for the period January 2006 - December 2006. Three new projects listed in that filing addressed (a) "Clean Air Interstate Rule (CAIR) Implementation," (b) "Clean Air Mercury Rule (CAMR) Implementation" and (c) "Best Available Retrofit Technology (BART) Rule Implementation." The filing showed that Gulf expected to begin incurring preliminary engineering and design costs during 2006 to determine the best strategy to comply with CAIR and similar costs for strategy development in connection with CAMR and BART. The filing also stated that CAIR may require the construction of a flue gas desulfurization scrubber ("scrubber") at Plant Crist on Unit 6 and Unit 7 as well as selective non-catalytic reduction ("SNCR") technologies at Plant Smith on Unit 1 and Unit 2 and that the CAMR project will include emission controls and emission monitoring equipment at multiple units.

4. In his direct testimony filed on September 16, 2005, Gulf's Director of Environmental Affairs, James O. Vick, specifically discussed projects expected to be necessary for compliance with CAIR, the BART requirements under the Regional Haze Rule (now known as CAVR), and CAMR. Mr. Vick's testimony indicated an estimated initial in-

service date of April 2010 for the Plant Crist scrubber system that was expected to be necessary for compliance with CAIR and CAVR.

5. As part of the prehearing process for Docket No. 050007-EI, the parties agreed to defer issues 11G and 11H, which had been framed with regard to the CAIR and CAMR implementation projects. The Commission subsequently approved that stipulation at pages 11-12 of Order No. PSC-05-1251-FOF-EI, issued December 22, 2005, in Docket No. 050007-EI:

> We approve as reasonable the following stipulation regarding recovery of costs associated with planning and construction of the proposed Scrubber Project at Plant Crist, and recovery of costs associated with planning and construction of the proposed baghouse project at Smith Unit 2.
>
> The Scrubber Project (Line Item 1.26) discussed in Issue 11G [*Should the Commission approve recovery of costs associated with planning and construction of the proposed scrubber project at Plant Crist?*] and the Plant Smith Baghouse Project (Line Item 1.27) discussed in Issue 11H [*Should the Commission approve recovery of costs associated with planning and construction of the proposed baghouse project at Smith Unit 2?*] are proposed as additions to Gulf's Air Quality programs in order for Gulf to comply with new environmental regulations, including the EPA's Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR), as described in the testimony of Gulf's witness James O. Vick filed on September 15, 2005. CAIR and CAMR are "environmental regulations" as defined in Section 366.8255(1)(c), and costs incurred to comply with these rules are eligible for recovery through the Environmental Cost Recovery Clause. The Scrubber Project and the Baghouse Project are capital projects of such magnitude in dollars and construction time that the Commission's policy regarding AFUDC is applicable. As a result, there is no dollar impact on the ECRC factors for 2006 from these programs. Any money actually spent on these projects in 2006 will be capitalized along with the applicable AFUDC and will be reflected in the proposed ECRC factors for the year when the projects are expected to close to plant-in-service. Although the EPA's CAIR and CAMR are subject to on-going rule challenges which may change the need for the proposed action, at this time the effective date of the rules as promulgated by the EPA have not been stayed. The FDEP has not yet adopted its rules implementing CAIR/CAMR at the state level, but is expected to do so during 2006. As a result, Gulf's decisions regarding the appropriate strategy for CAIR/CAMR compliance are still subject to review. For this reason, Issues 11G and 11H and any consideration of the prudence and reasonableness of

> specific technologies and associated project costs related to Gulf's CAIR/CAMR activities, including the costs to implement these projects during 2006, shall be deferred to later proceedings in this ongoing docket after Gulf has finalized its decisions regarding these two projects and has submitted additional testimony supporting its choice of CAIR/CAMR compliance options. The deferral of these issues shall not prejudice the rights of Gulf or any parties to this docket with respect to the projects identified in these issues. The deferral shall not be construed as a restriction on Gulf's ability to spend money during 2006 on these projects that are intended for future recovery through the ECRC mechanism and such money shall remain eligible for ECRC recovery subject to future reasonableness and prudence review by the Commission following the filing of Gulf's additional evidence regarding its final compliance strategy. Likewise, the deferral shall not prejudice the rights of OPC and other parties to conduct discovery and possibly challenge the reasonableness or prudence of any projects or associated costs related to Gulf's CAIR/CAMR compliance strategy in such future proceedings. Mr. Vick's testimony shall be entered in the record, but receipt thereof shall not be considered as the Commission's approval of the reasonableness and prudence of Gulf's CAIR and CAMR compliance projects.

6. On July 14, 2006, Gulf filed its Preliminary List of New Projects for Cost Recovery for the period January 2007 - December 2007. In that filing, the Company reported that as part of its CAIR/CAMR compliance project/program, Gulf had begun engineering, design, and other planning activities to determine the most reasonable, cost-effective control strategy for compliance with CAIR and CAMR. Gulf's filing further reported that the Company's compliance strategy will require the construction of a scrubber at Plant Crist, with some portions of the Plant Crist scrubber project expected to be placed in service during 2007. The filing also noted that additional controls may be needed at other facilities, including new emission monitoring equipment for mercury compliance verification.

7. Gulf's petition and testimony for the November 2006 ECRC hearing were filed on September 1, 2006. Gulf's petition included a section seeking approval of the Company's CAIR/CAMR environmental compliance program. As part of its petition and the supporting

testimony of Mr. Vick, Gulf advised the Commission that the Company has determined that the most reasonable strategy for compliance with CAIR, CAMR and the BART requirements of the Regional Haze Rule (now known as CAVR) is to utilize a combination of pollution control technologies on its coal-fired generation along with supplemental purchases of allowances as warranted. Gulf reported that for the 2007-2012 time period, Gulf's CAIR/CAMR environmental compliance program was then expected to require the addition of scrubbers at Plants Crist (2009) and Daniel (2011), selective catalytic reduction ("SCR") control technology at Plant Crist on Unit 6 (2010), SNCR controls at Plants Smith (2009), Scholz (2010), and Daniel (2009), as well as Low NO_x burners ("LNBs") at Plant Daniel (2009). The CAIR/CAMR environmental compliance program was then also expected to require installation of new mercury emission monitoring equipment for mercury compliance verification at all of Gulf's coal-fired generating units at Plants Crist, Daniel, Smith and Scholz (2007-2008). For the 2013-2017 time frame, Gulf's CAIR/CAMR environmental compliance program was then currently projected to include the addition of a scrubber and a baghouse at Plant Smith and SCRs at Plant Daniel. As reported in Gulf's September 2006 petition and the supporting testimony of Mr. Vick, the actual initial in-service dates for this equipment will be partially determined by the final BART rules and the onset of Phase II of the Florida CAIR, the Florida CAMR, the Mississippi CAIR, and the Mississippi CAMR.

GULF'S CAIR/CAMR/CAVR ENVIRONMENTAL COMPLIANCE PROGRAM

8. As noted earlier, Exhibit A is a copy of Gulf's Compliance Plan. The first three sections of Exhibit A provide (a) an executive summary, (b) a discussion of the requirements of CAIR, CAMR and CAVR, and (c) a discussion of the planning process utilized by Gulf to select the most reasonable and prudent strategy for compliance with environmental laws and

regulations in general, and in particular the requirements of CAIR, CAMR and CAVR. Section 4 of Exhibit A is devoted to a discussion of the actual program planning evaluation for CAIR, CAMR and CAVR. Section 5 of Exhibit A is a discussion of Gulf's current plan for compliance with CAIR, CAMR and CAVR on a plant- and/or unit-specific basis.

9. Overall, Exhibit A identifies the timing and current estimates of costs for specific projects planned by the Company in order to comply with CAIR/CAMR/CAVR requirements along with information regarding the relative value of the planned projects compared to other viable compliance alternatives, if any. Exhibit A also includes the description and results of the evaluation process that lead Gulf to conclude that the chosen means of compliance is the most reasonable, cost-effective alternative and that the affected generating units remain economically viable as a source of energy to Gulf's retail customers with the addition of the controls.

10. As discussed in Section 5 of Exhibit A, Gulf's Compliance Plan includes the addition of several retrofit applications at Plant Crist, Plant Daniel[2], Plant Smith and Plant Scholz:

> a. <u>Crist Units 4 through 7 Scrubber</u>. Gulf has determined that a scrubber for Units 4 through 7 is the most reasonable, cost-effective means of removing SO_2 and mercury. Construction of the Crist scrubber is scheduled to take place from 2007 through 2009 at an estimated capital cost of approximately $530 million. Based upon plant specific circumstances, Gulf has chosen the Chiyoda technology for the Plant Crist scrubber. This installation will reduce SO_2 emissions by approximately 43,000 tons per year and mercury emissions by approximately 3,800 ounces per year. Even with this retrofit, Gulf will have to manage compliance through reliance on its bank of allowances and the purchase of additional allowances from the market.

> b. <u>Crist Unit 6 SCR.</u> Gulf has determined that a SCR for Crist Unit 6 is necessary to meet not only required NO_x reductions, but also to assure that Pensacola maintains attainment with the new 8-hour ozone standard. The Crist Unit 6 SCR will also serve to mitigate significant local pressure to continue NO_x reductions from the plant. The Crist Unit 6 SCR will be constructed between 2007 and 2011 and is

[2] Plant Daniel Units 1 and 2 are co-owned by Gulf and its sister company, Mississippi Power Company.

forecasted to have a total capital cost of approximately $84 million. The Crist Unit 6 SCR will help assure CAIR compliance as well as CAMR compliance.

c. Crist Units 4 through 7 CAIR and Mercury Monitors. CAIR will require a continuous emission monitoring system for the scrubber. CAMR will require continuous mercury emission monitoring on all four Crist units and the scrubber. The current projected capital cost for these monitoring systems is approximately $4.6 million.

d. Daniel Units 1 and 2 Scrubber. Gulf and Mississippi Power have determined that a scrubber for Daniel Units 1 and 2 is needed to meet the requirements of CAIR, CAMR and CAVR. Construction of this scrubber is scheduled for 2007-2011 at an estimated capital cost of approximately $187 million (Gulf's ownership share). Based upon plant-specific circumstances, Gulf and Mississippi Power have chosen the Advatech single tower technology for the Plant Daniel scrubber. This scrubber will reduce SO_2 emissions by approximately 18,000 tons per year and mercury emissions by approximately 2,000 ounces per year. Even with this retrofit, Gulf and Mississippi Power will have to manage compliance through reliance on their bank of allowances and the purchase of additional allowances from the market.

e. Daniel Units 1 and 2 SCRs. Gulf and Mississippi Power have determined that SCRs for Daniel Units 1 and 2 are necessary to help meet CAIR, CAMR and possibly 8-hour ozone nonattainment. The Daniel Units 1 and 2 SCRs will be constructed between 2012 and 2017 and are forecasted to have a total capital cost of approximately $153 million.

f. Daniel Units 1 and 2 SNCRs and Low NO_x Burners. Gulf and Mississippi Power have determined that to meet CAIR annual and seasonal NO_x requirements and possibly to avoid 8-hour ozone nonattainment, the installation of SNCRs and LNBs are necessary. The SNCRs will be installed between 2009 through 2011 at an estimated capital cost of approximately $7.5 million, and the LNBs are scheduled to be installed between 2007 and 2010 at an estimated cost of approximately $7.8 million.

g. Daniel Units 1 and 2 CAIR and Mercury Monitors. CAIR will require a continuous emission monitoring system on the Plant Daniel scrubber and CAMR will require continuous mercury emission monitoring on both Plant Daniel coal units and the scrubber. The current projected capital cost for these monitoring systems is approximately $877,000.

h. Smith Units 1 and 2 Scrubber. Gulf has determined that a scrubber for Smith Units 1 and 2 will likely be needed to meet CAVR requirements by 2017. The current estimated cost for this scrubber project is $251 million, which would be expended from 2013 through 2018. The compliance plan for Plant Smith remains very flexible.

i. <u>Smith Units 1 and 2 SNCRs.</u> Gulf has determined that SNCRs for Smith Units 1 and 2 are the most reasonable, cost-effective means of meeting CAIR annual and seasonal NO_x caps and that such installations should also help maintain local compliance with the 8-hour ozone standard. The SNCR projects for Smith Units 1 and 2 will be constructed between 2007 and 2009 and are forecasted to have a total capital cost of approximately $10 million.

j. <u>Smith Unit 2 Baghouse</u>. Gulf anticipates that the construction of a baghouse at Smith Unit 2 will be required to meet CAMR requirements by 2018. Gulf's Compliance Plan includes a capital cost estimate of approximately $55.6 million for construction of this baghouse during 2015 through 2018.

k. <u>Smith Units 1 and 2 CAIR and Mercury Monitors.</u> CAIR will require a parametric emission monitoring system on the Smith combustion turbine and a continuous emission monitoring system on the Smith scrubber. CAMR will require continuous mercury emission monitoring on both Smith coal units and the scrubber. The current projected capital cost for these monitoring systems is approximately $2 million.

l. <u>Scholz Units 1 and 2 Mercury Monitors.</u> CAMR will require mercury monitoring on both coal units at Plant Scholz. The current projected capital cost for these monitoring systems to be installed in 2007 and 2008 is approximately $1 million.

The addition of the control technologies identified above and incorporated in Gulf's Compliance Plan are the most reasonable, cost effective alternatives available to Gulf for its generating fleet. Gulf's adoption of its Compliance Plan is reasonable and prudent and should be approved as such by the Commission.

11. As further discussed in Section 5 of Exhibit A, in addition to the retrofit applications described above, Gulf will still have to manage compliance through reliance on its bank of emission allowances and the purchase of additional emission allowances from the market. The projected levels and costs of emission allowances to be purchased under Gulf's Compliance Plan are shown on Table 5.5-1 of Exhibit A.

WHEREFORE, Gulf Power Company respectfully requests that the Florida Public Service Commission issue its order approving the reasonableness and prudence of the Company's plan to achieve and maintain compliance with the Clean Air Interstate Rule ("CAIR"), the Clean Air Mercury Rule ("CAMR") and the Clean Air Visibility Rule ("CAVR") as set forth in Gulf's Compliance Plan, a copy of which is attached to this supplemental petition as Exhibit A. Consistent with the stipulation of the parties approved by the Commission as set forth at page 9 of Order No. PSC-06-0972-FOF-EI issued November 22, 2006, in Docket No. 060007-EI, Gulf Power further requests that the Commission set forth its approval of the Company's plan as reasonable and prudent through the issuance of a Proposed Agency Action ("PAA") order or other similar mechanism ("the requested PAA order") that will require interested parties that object to any components of Gulf's CAIR/CAMR/CAVR compliance program with regard to the reasonableness or prudence of the Company's proposed action to specifically state their objections prior to June 30, 2007, and thereby request that the resulting issues be set for hearing in the normal course of this ongoing docket regarding the Environmental Cost Recovery Clause ("ECRC"). In the event that the Commission is not able to issue the requested PAA order such that the parties are compelled to respond before June 30, 2007, Gulf respectfully requests that the prehearing officer issue an order directing the Commission Staff and interested parties to file a notice prior to June 30, 2007, stating with specificity their objections, if any, to any component of the CAIR/CAMR/CAVR program with regard to the reasonableness or prudence of the Company's proposed action so that testimony and exhibits addressing the resulting issue(s) can be filed in the normal time frame for the 2007 ECRC hearing and the issue(s) can be resolved by the Commission in the normal course of the ongoing ECRC proceedings. Gulf

Power further requests that the Commission grant such other relief as is just and reasonable under the circumstances set forth in this supplemental petition.

Respectfully submitted this 29th day of March, 2007.

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Exhibit A

GULF POWER COMPANY
ENVIRONMENTAL COMPLIANCE
PROGRAM

for the

Clean Air Interstate Rule
Clean Air Mercury Rule
Clean Air Visibility Rule

March 29, 2007

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1.0 EXECUTIVE SUMMARY

Since the Clean Air Act Amendments (CAAA) were passed by Congress in 1990, Gulf Power Company (Gulf Power or Gulf) has reviewed and updated its environmental compliance plan as needed on an on-going basis. The goal of this process is to identify reasonable, cost-effective compliance strategies that will minimize the impact on Gulf Power's customers while achieving environmental objectives and assuring compliance with all environmental requirements.

This document: (a) addresses the requirements of the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and the Clean Air Visibility Rule (CAVR); (b) reviews the decision process for assuring compliance at Gulf Power; and (c) provides cost estimates for incorporating these requirements at Gulf Power. The document reviews the specific issues, timing, alternatives, process, and costs necessary for compliance with the new federal rules and the corresponding implementation programs developed by the Florida Department of Environmental Protection (FDEP) and the Mississippi Department of Environmental Quality.

Gulf Power has remained in compliance with all requirements of the CAAA and has addressed local concerns regarding ozone nonattainment in Pensacola and along the Gulf Coast. Implementation of the plan described in this document will assure continued compliance. The timing of the requirements and costs incurred will be a function of the compliance options selected, fuel burn, energy demand, fuel sulfur content, availability and prices for allowance purchases, natural gas prices, performance of emission control equipment, and other variables.

A capital and operations and maintenance (O&M) cost summary for CAIR, CAMR, and CAVR is provided in Table 1.0-1. Detailed capital and O&M costs are provided in Section 5 of this document. Gulf Power's compliance plan for CAIR, CAMR, and CAVR will be impacted by factors such as Florida's implementation of these rules, changes to existing environmental laws and regulations, the cost of emissions allowances, performance of emission control equipment, and any change in the use of coal. Based on these factors, future environmental compliance costs will continue to be incurred, and projections will be revised.

Beyond CAIR, CAMR, and CAVR, many of the future regulatory requirements, especially those needed to attain current and future ozone and fine-particulate ambient standards and reasonable progress visibility requirements, will be aimed at further nitrogen oxide (NO_X) and sulfur dioxide (SO_2) reductions. All of this uncertainty reinforces the need for a flexible, robust compliance plan. Accordingly, as decision dates for equipment purchases approach, and as better information relative to regulatory and economic drivers becomes available, the analysis will be updated as needed to enable the selection of the most reasonable and cost-effective compliance alternatives while maintaining future flexibility in the plan.

Table 1.0-1

Projected Environmental Capital and O&M Costs for CAIR, CAMR and CAVR by Plant

Plant	Capital Expenditures[a] 2007-2018 ($M)	O&M Expenses[b] 2007-2016 ($M)
Crist	616	71
Daniel[c]	356	45
Smith	318	21
Scholz	1	2
TOTALS	1,291	139

a. Capital expenditures are projected through 2018 to include the total project expenditures for those projects that began during the ten year forecast period.
b. Gulf's O&M budget projection is based on a ten year forecast.
c. Costs for Gulf Power's ownership portion of Plant Daniel in Mississippi.

2.0 REGULATORY AND LEGISLATIVE UPDATE

This section provides a regulatory and legislative update and review of the CAIR, CAMR, and CAVR. Background information on the Clean Air Act, acid rain requirements, ambient air quality standards, land/water requirements, and other related issues is presented in Appendix A. The appendix information is included to establish the relationships among many environmental requirements.

2.1 CLEAN AIR INTERSTATE RULE

In March 2005, the Environmental Protection Agency (EPA) published the final CAIR, a rule that addresses transport of SO_2 and NO_X emissions that contribute to nonattainment of the ozone and fine particulate matter National Ambient Air Quality Standards in the Eastern United States. This cap and trade rule addresses power plant SO_2 and NO_X emissions that were found to contribute to nonattainment of the 8-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including Florida and Mississippi, are subject to the requirements of the rule (see Figure 2.1-1). The rule calls for additional reductions of NO_X and SO_2 to be achieved in two phases, 2009/2010 and 2015, as shown in Table 2.1-1. For Gulf, compliance will be accomplished by the installation of additional emission controls at its coal-fired facilities and/or by the purchase of emission allowances from the rule's cap and trade program.

Table 2.1-1

CAIR Emission Reduction Requirements

Emissions	Phase I reduction from acid rain allocations or current emissions	Phase II reduction from current allocations or current emissions
SO_2	50% (2010)	66% (2015)
NO_X	50% (2009)	65% (2015)

CAIR sets a permanent cap on emissions levels and provides for an allowance trading market. SO_2 allowances are set by the rule to follow the acid rain program's allocation process. Affected states have the option to adopt the Federal CAIR model rule process for the allocation of NO_X allowances or to develop alternative allocations.

Florida has proposed an implementation plan which generally follows the federal rules. CAIR State Implementation Plans (SIP) were due in September 2006, but due to a legal challenge regarding the NO_X allowance process by another utility, the FDEP missed the SIP submittal date. On March 1, 2007, the Administrative Law Judge issued a Final Order upholding Florida's CAIR rule and dismissed the petition for rule challenge. There is a possibility of an appeal of the Final Order, thus, Florida has temporarily defaulted to the Federal Implementation Plan for CAIR until the challenge is resolved. Gulf Power supports the FDEP CAIR rule as proposed in the June 2006 adoption hearing. An adverse ruling in the case could substantially increase Gulf's compliance costs for CAIR.

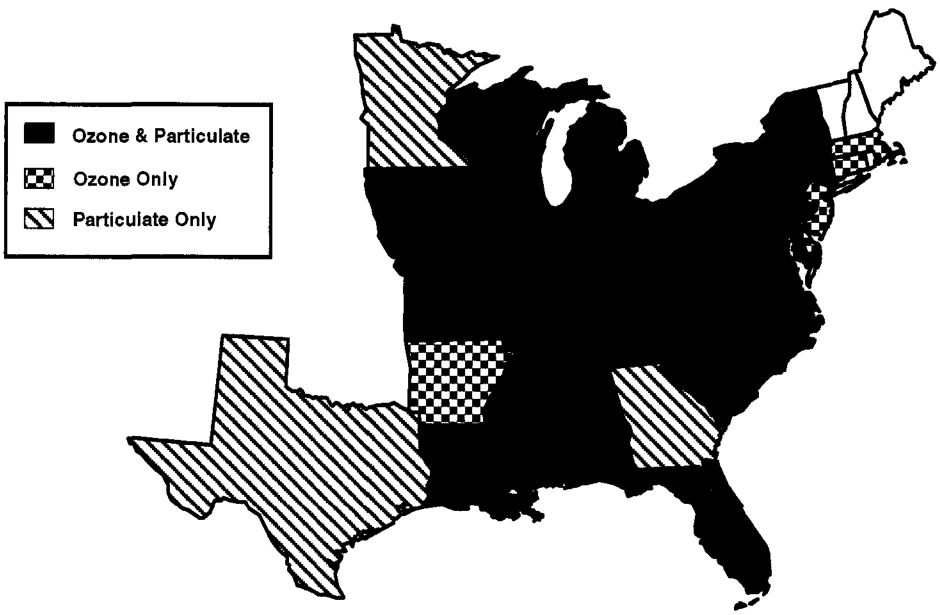


Figure 2.1-1 Clean Air Interstate Rule, State Designations

For the State of Mississippi, all CAIR requirements and provisions as amended and promulgated by the EPA as of September 2006 have been adopted and incorporated by reference as the official CAIR implementation plan for Mississippi. SO_2 and NO_X allowance allocations will be determined and established as outlined by the EPA model federal program.

The State of Florida and State of Mississippi CAIR implementation rules are provided in Appendix D.

2.2 CLEAN AIR MERCURY RULE

In March 2005, the EPA published the final CAMR, a cap and trade program for the reduction of mercury emissions from coal-fired power plants. The rule sets caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provides for an emission allowance trading market. In the first phase, the national cap on utility industry mercury emissions is 38 tons; in the second phase, the cap is 15 tons (from a baseline of about 45 tons). The requirements and the timing are summarized in Table 2.2-1.

Table 2.2-1

CAMR Emission Reduction Requirements

Emissions	Phase I	Phase II
Cap & Trade	30% Reduction (2010)	70% Reduction (2018)

The majority of the reductions required for the first phase are expected to be met through co-benefits from the implementation of scrubber and selective catalytic reduction systems for the control of SO_2 and NO_X under the CAIR rule. However, emission control equipment and options for mercury emission reductions are still being evaluated. CAMR will require continuous monitoring and reporting of mercury emissions. Monitoring systems must be installed, certified, and operational by January 2009.

The CAMR plan proposed by the State of Florida for Phase I begins with a 95-5 allocation plan for the first two years, with 95 percent of the EPA State allowances allocated to existing sources, 5 percent held for new units and any unused allowances for new units redistributed to existing sources. After two years, the Phase I program becomes more stringent with a 70-25-5 plan, where 70 percent of the allowances will be allocated to existing sources, 25 percent allocated to a supplemental compliance pool for use by sources with full-time emission controls who need extra allowances should they fail to meet their unit allocation, and 5 percent for a "new unit set aside." The program follows a cap and trade model allowing unlimited trading but with only 70 percent of the allowances allocated after 2012 for Phase I. Sources are free to purchase unlimited allowances in the market. Any allowances in "new unit set aside" not used each year would be redistributed to existing sources. However, none of the 25 percent supplemental compliance pool allowances that go un-used each year will be redistributed. For Phase II, Florida currently plans to implement the Federal model rule and program. The State of Mississippi has proposed to adopt the Federal CAMR model rule.

The State of Florida and State of Mississippi rules for the implementation of CAMR are provided in Appendix E.

2.3 CLEAN AIR VISIBILITY RULE

The CAVR, formerly the Regional Haze Rule, was finalized in July 2005. The goal of CAVR is to restore natural visibility conditions in certain areas (primarily national parks and wilderness areas as shown in Figure 2.3-1) by 2064. The rule involves (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977, and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress toward the natural conditions goal by 2018 (reasonable progress program). Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate "reasonable progress" in each area. For power plants, the CAVR allows states to determine that the CAIR satisfies BART requirements for SO_2 and NO_X. However, additional BART requirements for particulate matter could be imposed, and the reasonable progress provisions could result in requirements for additional SO_2 emission controls beyond those required by CAIR. By December 17, 2007, states must submit implementation plans with strategies for BART and any other control measures required to achieve the first phase of "reasonable progress."

CAVR is a command and control program as opposed to a cap and trade program. As a result, Gulf anticipates that compliance with CAVR will require specific retrofit equipment installations. The Federal model CAVR rules for the implementation of CAVR are provided in Appendix F.

Figure 2.3-1 Clean Air Visibility Rule and Federal Class I Areas

3.0 ENVIRONMENTAL COMPLIANCE PROGRAM PLANNING

Since Gulf Power, as a part of Southern Company, completed the initial environmental planning process following the passage of the 1990 Clean Air Act Amendments, the Company has followed an on-going process to develop, review, and update environmental compliance strategies using sophisticated, state-of-the-art analytical tools. The goal of this process is to identify reasonable, cost-effective compliance strategies that will minimize the impact on Gulf Power's customers while achieving environmental objectives and assuring compliance with all environmental requirements. This process is illustrated in Figure 3.0-1.

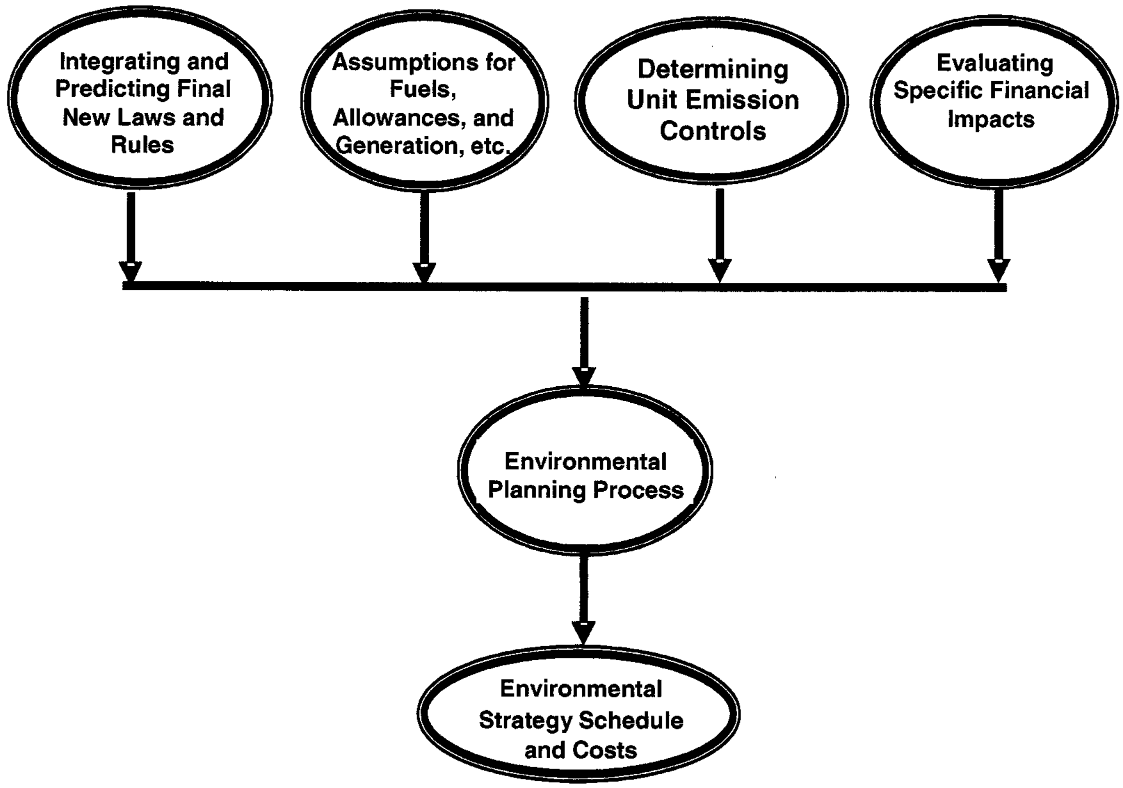


Figure 3.0-1 Environmental Planning Development Process

The development of the environmental compliance plan involves input from a number of organizations from across Gulf Power and Southern Company, including environmental affairs, governmental affairs, resource planning, fuels, engineering, finance, operations, communications, generating plants, and research groups. The process evolves through a series of collaborative discussions where requirements, modeling data, emissions information, emissions technologies, costs, and schedules are examined in detail. This integrated process includes four primary steps.

1. **Predicting and integrating the outcome of new environmental requirements**. The first step involves identification of current and possible future local, state, regional, and national environmental requirements. The future requirements may be in the form of legislation that will need future rulemakings or in the form of draft or proposed new rules that must go through the rulemaking process to become final. Some rules may be part of an allowance-based cap and trade program over a regional or national scale, and others may be local or state requirements that mandate specific requirements on specific plants.

2. **Developing assumptions.** The Company must make assumptions to predict generating unit, Gulf Power, and national electric system responses to existing and future environmental requirements (in addition to growing demands for electricity). These assumptions include:

    - Unit operating characteristics such as heat rates, capacity, and emission rates
    - Fuel characteristics and costs, including natural gas, coal, and oil
    - Allowance prices for cap and trade programs
    - Control technology options and costs
    - Replacement power costs
    - Future generation demand
    - Future O&M and capital cost projections associated with continued operation of the generating unit

3. **Application of reasonable, cost-effective compliance options.** The application of reasonable compliance options is dictated initially by the anticipated emission control requirements for each specific generating plant and/or unit. In some cases, the plant's or unit's emission control requirements are mandated, such as a plant-specific or unit-specific limit to meet local air quality requirements. In some cases, such as the regional/national cap and trade programs (e.g. acid rain, CAIR, CAMR), utilities can choose from among several compliance options for each specific generating plant

and/or unit: fuel switching, purchasing emission allowances, retirement/replacement, or applying control technology. The environmental planning process reviews the cost-effectiveness and the overall viability of each of these options.

The availability of control technology options varies by pollutant as well. (See Appendix C for a discussion of emission control options.) For example, when complying with SO_2 reduction requirements, the choices are basically fuel switching, installing flue gas desulfurization devices (scrubbers), or buying allowances. In contrast, for NO_X control there are more control technology options available such as low-NO_X burners (LNBs), selective catalytic reduction (SCR), and selective noncatalytic reduction (SNCR). The cost, control effectiveness, and appropriateness of each technology for each unit are considered in making decisions to install emission controls, delay controls, or replace the capacity.

All of these considerations are taken into account in developing a unit-specific decision on the application of emission compliance options. Figure 3.0-2 illustrates this decision process.

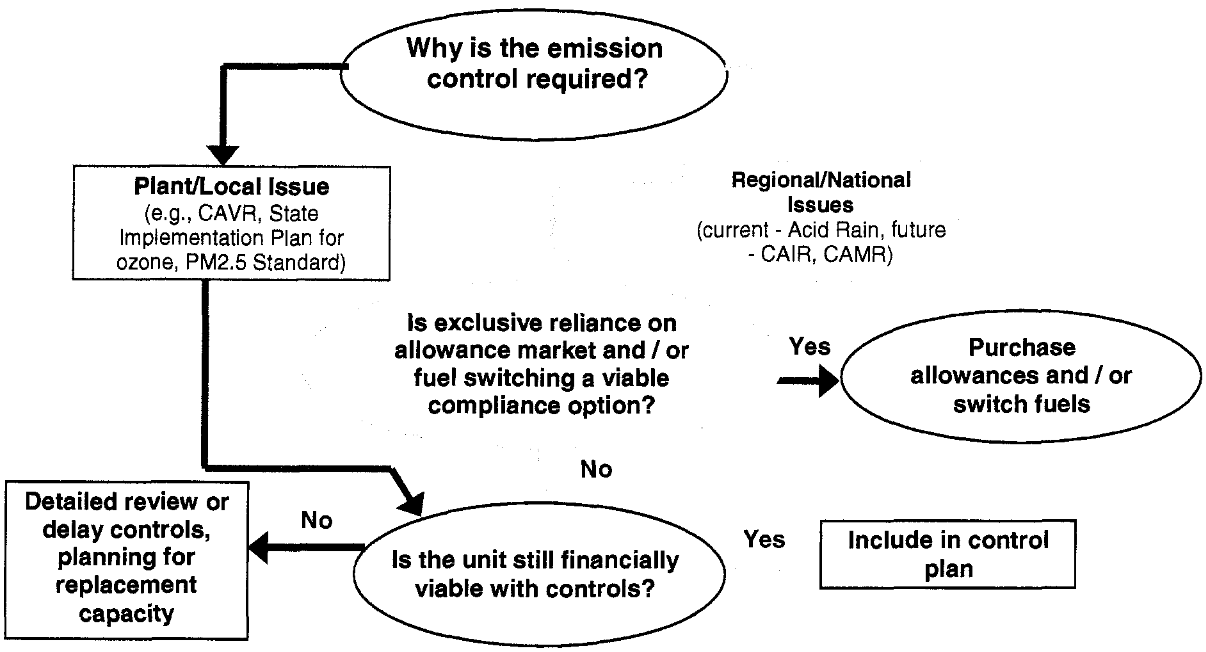


Figure 3.0-2 Determining Compliance Options for Emission Control

4. **Determining and evaluating the financial impacts of the plan.** The final step is to make sure that the right financial decision is being made for Gulf's customers. Some units and plants may not be able to achieve the necessary emission reductions with only control technologies and would need to acquire additional allowances to comply. If emission reductions are mandated for a specific plant and/or unit, the financial value of the generating asset, including future operating costs, must be considered before application of the technology.

4.0 PROGRAM PLANNING EVALUATION

4.1 COMPLIANCE REQUIREMENTS

The combined effect of the 1990 CAAA and the 2005 CAIR and CAMR rules have reduced the overall allowed emissions from utility generators. Although the CAIR and CAMR allowance allocations are not yet finalized, there is a sufficient basis to establish a forecast of allocation targets useful in projecting compliance shortfalls and formulating control strategies. Based on forecasted allowance allocations, Gulf Power will be required to make a significant reduction in certain emissions from its generating units.

According to forecasted generation and estimated allowance allocations, Gulf Power will face a significant compliance (allowance) shortfall without installing additional emission controls. If Gulf Power's units maintain the same amount of generation as calculated in energy budget forecasts without the benefits of additional emission controls, then Gulf Power's shortfall of SO_2 allowances would be approximately 477,000 tons over the next ten years. Additionally, approximately 48,000 ounces of mercury allowances, approximately 102,000 tons of annual NO_X allowances, and approximately 45,000 tons of seasonal NO_X allowances would be required during the same ten year period. See Tables 5.2-1 through 5.2-4 for further details.

4.2 COMPLIANCE OPTIONS

A comprehensive environmental compliance planning evaluation considers a range of options for economically meeting the energy needs of Gulf Power's customers. Gulf Power investigated four major options for environmental compliance:

- Dependence on allowance purchases
- Fuel switching
- Retrofit of environmental emission controls to existing generating units
- Retirement of existing generating units and replacement with new or purchased generation

Combinations of these options were also considered.

4.2.1 Allowance Purchase Option

The CAIR and CAMR rules both proposed cap and trade programs. Cap and trade programs use a market-based approach to reduce emissions. The program sets a cap, or limit, for each pollutant such as SO_2, NO_X, and mercury, which is then divided into emission allowances that are allocated to each affected source. Sources are allowed to determine the most reasonable, cost-effective way to comply. Facilities may install environmental emission controls, use fuel switching, replace the generating units, rely on the emission allowance market, or use some combination of these options.

In addition to the SO_2 (acid rain) and seasonal NO_X (ozone) allowance markets that were introduced by the 1990 CAAA, the CAIR and CAMR will shortly introduce two additional allowance markets: annual NO_X and mercury. The annual NO_X market is expected to emerge as soon as allocations are populated by the EPA.

4.2.2 Fuel Switching Option

Fuel switching refers to instances where an electric generating unit's primary fuel is changed to reduce emissions. In Gulf's case, fuel switching to lower sulfur coal was shown under the acid rain program to be a cost effective means for reducing emissions of SO_2. For certain facilities, NO_X emissions can be reduced by burning high-moisture, low-Btu sub-bituminous coals, while mercury emissions can be reduced by utilizing coal lower in mercury content.

4.2.3 Retrofit Options

Retrofit options refer to additional environmental emission controls that can be installed on existing generating units. As discussed in Section 2, affected coal-fired electric generating units, will be required to comply with SO_2, NO_X, and mercury emission limits under CAIR, CAMR, and CAVR, if the units are to continue to operate. These reductions may be met by installing additional SO_2, NO_X, and mercury emission controls on existing units. Currently, the proven control technology of choice for SO_2 reduction is wet scrubbing. For NO_X removal, there are a number of proven emission controls available such as SCR, SNCR, and LNBs. Mercury reductions can generally be met through the co-benefits of scrubber and SCR installations or via the use of baghouses.

SO_2 Reductions- Scrubbers

The only commercially available option for SO_2 emission reductions at the level needed to assure compliance with CAIR, CAMR, and CAVR is through a chemical process called flue gas desulfurization (FGD), commonly referred to as scrubbing. Various dry and wet scrubber processes have been successfully demonstrated and applied in recent years.

Dry scrubber processes involve the injection of alkaline slurry into the flue gas stream to absorb SO_2. A baghouse is typically required downstream of the dry scrubber to remove the residue. Dry scrubbing can remove 75 to 90 percent of SO_2, depending on coal sulfur content, with higher sulfur content resulting in lower SO_2 capture. Dry scrubbing was not selected as a technology of choice because it reduces fuel flexibility in order to meet sulfur removal rates, potentially increasing fuel costs.

Wet scrubber processes treat the flue gas from a coal-fired generating unit with a water-based solution or slurry. This process may involve a spray tower, fountain, or a large bubbling reactor. The common chemical used for the reaction is limestone, and the product of the reaction with SO_2 is gypsum. The process is very efficient and can remove 80 to 99 percent of the SO_2 with 95 percent removal typical. (See Table 4.2-1 for a summary of SO_2 removal efficiencies.) This technology has been proven to work on large generating units, such as those at Plants Crist, Daniel, and Smith. It is significant to note that additional flue gas streams can be added to a large, single-vessel scrubber at low incremental costs. In addition to SO_2 removal, wet scrubbers also provide a co-benefit of removing mercury. Mercury removal of about 45 percent can be expected with a wet scrubber.

Table 4.2-1

Emission Control Technologies and Typical Removal Efficiencies

Technology	Estimated % Removal
Scrubber*	80 – 95% SO_2, 45% Hg
SCR*	80 – 90% NO_X
LNBs	25 – 50% NO_X
SNCR	15 – 40% NO_X
Baghouse	50 – 80% Hg

* A scrubber and a SCR together can reduce mercury (Hg) emissions by about 80 percent.

Consequently, the proven technology of choice for SO_2 reduction is wet scrubbing. Two wet technologies were considered for scrubber projects, the Chiyoda jet bubbling reactor and the Advatech spray tower. The Chiyoda technology involves bubbling flue gas through a large vessel that contains a water-limestone slurry. The Advatech technology is based on a sprayer or fountain technology that involves contact with flue gas as the limestone fountain is sprayed up and as the slurry falls back in the tower.

In summary, although scrubbing is intended primarily as an SO_2 emission control technology, a scrubber can also effectively reduce mercury emissions. Depending on the coal and equipment specifics at each facility, a wet scrubber can be expected to remove about 45 percent of mercury in the flue gas. Together with a SCR, a wet scrubber can remove about 80 percent of the mercury, because elemental mercury is oxidized in the SCR for capture in the scrubber. A scrubber is also very effective in removing particulates, which can reduce or eliminate the need for a baghouse.

NO_X Reductions - SCR, SNCR, and LNBs

NO_X is a precursor to the formation of ozone in the atmosphere. NO_X reductions from industry, vehicles, and other sources contribute to reduced ozone in the atmosphere. A number of NO_X emission control alternatives are discussed in Appendix C. The three NO_X emission controls that Gulf selected for serious consideration (SCR, SNCR, and LNBs) are described below.

SCR is a post-combustion, chemical reaction technology for the control of NO_X emissions. The process involves injecting ammonia into the flue gas, in the presence of a catalyst, to produce molecular nitrogen and water vapor. SCRs require a supply of ammonia, and the catalyst bed must be replaced on a periodic basis, creating an ongoing O&M cost. Unlike scrubbers, which often treat the flue gas from several generating units, SCRs are designed to treat the flue gas from a single generating unit, because the temperature required for the reaction is critical. As shown in Table 4.2-1, a SCR can reduce NO_X emissions by 80 to 90 percent.

The NO_X emission levels possible from a SCR are much lower than can be achieved with LNBs or other low-NO_X combustion controls. As regulations and local requirements have been tightened in recent years, SCR has become the NO_X reduction technology of choice. No other current technology can reliably achieve the order of magnitude of NO_X reduction in as cost effective a manner.

A NO_X reduction technology that has evolved in recent years is SNCR. SNCR employs chemical injection of ammonia or urea directly into the boiler at a flue gas temperature between 1,600 and 2,100°F. In this temperature range, the reagent reacts with NO_X to form nitrogen and water without the use of a catalyst to promote the reaction. Application of

SNCR to utility-scale boilers is highly site specific and requires testing. Generally, SNCR is capable of 15 to 40 percent NO_X removal (See Table 4.2-1). One particular benefit of SNCR as compared to SCR is the capital cost is significantly less due to the absence of a catalyst and the associated reactor vessel. The SNCR requires a larger amount of ammonia or urea per unit of NO_x and, therefore, has higher chemical (O&M) costs as compared to a SCR. SNCR can be a cost-effective technology for medium and small-size coal-fired generating units.

LNB is a generic term for a burner designed to combust the fuel while reducing the amount of NO_X that is formed during combustion. Since there are several different firing arrangements commonly used in utility boilers, there are several different types of LNBs. LNB technology has been well proven and effective in reducing NO_X emissions for compliance with the requirements of the Acid Rain Program. As shown in Table 4.2-1, NO_X reductions of 25 to 50 percent can be achieved from LNBs.

Mercury Emission Reductions- Scrubber, Scrubber/SCR, and Baghouse

As discussed in Section 2, the EPA CAMR will require a 30 percent reduction in Phase I for mercury emissions from affected coal-fired electric generating units. Phase II of CAMR will require additional and significant reductions of 70 percent from these units beginning in 2018.

Reductions for CAMR Phase I can generally be met through co-benefits from the installation of scrubber and SCR systems for the control of SO_2 and NO_X emission reductions under the CAIR rule. Other emission control equipment and options for mercury emission reductions under CAMR are still being evaluated. Units that do not receive both a scrubber and a SCR may require other emission controls, such as a baghouse, for mercury control, especially for Phase II.

In addition to SO_2 removal, scrubbers provide a co-benefit of removing oxidized forms of mercury. Total mercury removals of about 45 percent can be expected with a wet scrubber, depending on the scrubber design, the coal burned, the content of chlorides in the coal, and other variables.

Where both a scrubber and a SCR will be installed, the SCR catalyst provides an additional co-benefit of converting a high percentage of the elemental mercury to the oxidized form. The oxidized mercury can then be captured by the scrubber. A wet scrubber, together with a SCR, can remove about 80 percent of the mercury in a flue gas stream for a unit burning eastern bituminous coal.

For units where neither a scrubber nor a scrubber and a SCR will be installed, a baghouse may be installed for the mercury removal requirements of CAMR Phase II. A baghouse is a fabric fiber particulate control device designed for the removal of particulate matter. Activated carbon or chemically treated carbon particles can be injected upstream of the baghouse. Mercury in the flue gas stream is absorbed by the carbon particles, which are subsequently captured by the baghouse. Mercury removals of up to 80 percent are expected from baghouses.

4.2.4 Retirement and Replacement Option

A retirement and replacement evaluation is used to compare retrofit compliance options to premature retirement and replacement of specific generating units in order to determine the most reasonable, cost-effective compliance option. These evaluations are performed at two levels of detail: (1) a screening level retirement/replacement evaluation and (2) a more detailed site specific replacement evaluation. The retirement option is typically more applicable to smaller, older, less efficient coal plants that cannot financially support the addition of environmental controls. A description of the evaluation methodology and screening level evaluation results are discussed in Section 4.3.4.

4.3 GULF'S EVALUATION OF COMPLIANCE OPTIONS

4.3.1 Evaluation of Allowance Purchase Option

The CAAA of 1990 first established two environmental cap and trade programs: SO_2 (acid rain) and seasonal NO_X (ozone). These existing emissions allowance markets have proven to be fundamentally driven by supply and demand. However, over time, many speculative investors have begun entering the allowance markets, particularly the SO_2 market, introducing considerable volatility and uncertainty concerning the price and availability of allowances. The chart shown in Figure 4.3-1 represents the volatility seen in the SO_2 allowance market over the past 18 months.

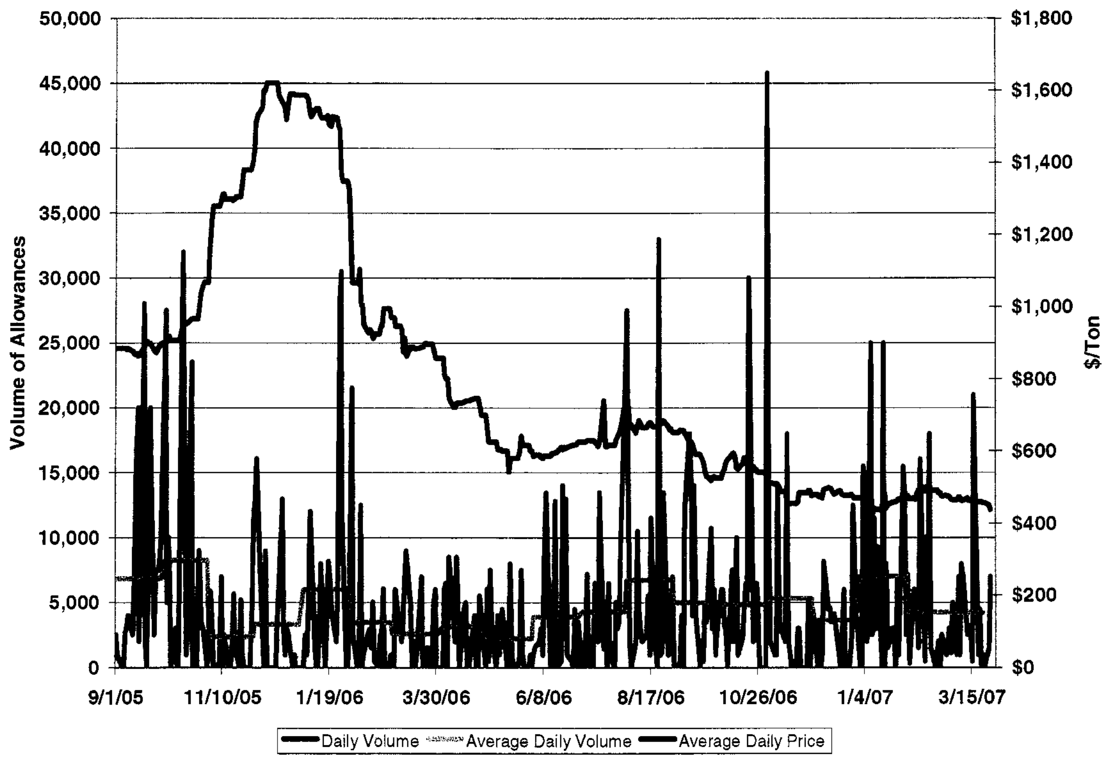


Figure 4.3-1 SO_2 Allowance Market Volatility

Source: Evolution Markets

The costs of compliance with the SO_2 programs represent the largest portion of Gulf Power's total environmental compliance program cost. With the high price volatility, yet low trading volumes seen in the SO_2 market to date, the future price and availability of allowances cannot be treated as predictable; therefore, depending solely on the market for SO_2 compliance presents a large risk for Gulf Power's customers. Additionally, should allowances not be available, Gulf Power might be forced to operate higher cost units while curtailing operation of lower cost units in order to maintain compliance.

CAIR and CAMR will shortly introduce two additional allowance markets: annual NO_X and mercury. These markets are expected to emerge as soon as the states finalize their implementation plans and allocations are populated by the EPA. In addition, the seasonal NO_X market will be expanded to cover a larger area that will include Gulf Power's generating units.

The mercury allowance market presents a unique set of concerns. As many as 21 states are expected to opt out of the Federal trading program. As a result, it is uncertain if a liquid market will form based on the number of utility participants. Mercury allocations are not expected to be populated for another year, creating more uncertainty and concern regarding the availability of this commodity.

Total dependence on these commodity markets for compliance would be very risky and potentially costly for Gulf Power and its customers. The market does, however, provide realistic opportunities for reducing costs through selected and limited purchases of allowances in conjunction with other options to achieve cost effective compliance.

In summary, in order for the allowance market based approach to be an appropriate solution for Gulf Power's compliance shortfall, these allowance markets must be established, reasonably stable, and have sufficient quantities of allowances available. Furthermore, to avoid short-term supply and demand volatility, these conditions must be met with sufficient lead time to allow time to pursue other options such as constructing emission controls. Given the timing of construction schedules and the compliance deadlines for the new rules, Gulf Power cannot wait to see if stable allowance markets emerge. These overall uncertainties eliminated the exclusive use of an all allowance purchase option from consideration.

4.3.2 Evaluation of Fuel Switching Option

Fuel switching was shown under the acid rain program to be cost effective for reducing emissions of SO_2. For certain facilities, NO_X emissions can be reduced by burning high-moisture, low-Btu sub-bituminous coals, and some coals are lower in mercury content than others. However, for the magnitude of emission reductions required by CAIR, CAMR, and CAVR, fuel switching is no longer a viable option.

As presented in the discussion below, emission reductions of the magnitude specified in the proposed CAIR will require additional pollution control equipment for most of Gulf Power's coal-fired units. Installation and operation of NO_X and SO_2 reduction systems will be required. Because much of this equipment will result in the co-benefit of mercury emission reduction, development of a plan for meeting the provisions of the CAIR and the CAMR (see Section 2.2) must be made concurrently.

4.3.3 Evaluation of Retrofit Options

Having determined that neither an all allowance plan nor an all fuel switching plan would be feasible or desirable, Gulf Power was left with the primary options of either retrofitting units or retiring and replacing units (and, if necessary, supplementing those options with allowance purchases or fuel switching). However, before making a comparison of retrofit and replacement options, Gulf Power first had to choose among competing retrofit options. This selection of the best retrofit option involved both technical and economic reviews.

Technical Review

As previously noted, there are often multiple retrofit emission control technologies available to reduce emission levels for existing units. The first determination is the level of emission reductions that will be required. This determination has the potential to eliminate control options that cannot meet required emission reductions.

Once the remaining control options are identified, assessments must be made to determine the preferred control technologies. Sometimes this is a generic determination of a preferable technology. For instance, Gulf Power's preference for wet versus dry scrubbers is based upon limitations of dry scrubbing, its restrictive fuel options and lower levels of SO_2 emissions removal. Wet scrubbers remove 80 to 99 percent of the SO_2, with a 95 percent typical removal, and dry scrubbers remove 75 to 90 percent of the SO_2.

Other determinations are based upon specific plant or unit circumstances and requirements. For instance, two competing wet scrubber technologies were considered for the scrubber projects at Gulf's plants: the Chiyoda jet bubbling reactor and the Advatech spray tower. The Chiyoda technology was chosen as the preferred scrubber technology for one plant, while Advatech was selected for another plant, due to specific requirements of the different generating units.

Economic and Constructability Review

While technical considerations are important in determining the best retrofit strategy and such considerations may dictate a retrofit option, there are instances where there are competing retrofit alternatives that must be evaluated further. In those instances, if specific plant characteristics do not dictate a choice, a consideration of the relative economics of the alternatives must be considered. Gulf Power conducts these analyses by performing studies to assess the economic effects of the control addition.

These studies consider both quantitative and qualitative aspects of constructing a control at a particular unit. The quantitative aspects included in the evaluation are the capital and O&M costs of the retrofit options. Due to the difficulty and cost of performing detailed cost estimates, a generic cost is utilized to enable a screening of all available options. This capital and O&M cost information is combined with other forecasts, such as projected electrical demand, fuel costs, emissions allowance costs, unit parameters, etc., in a software program designed to simulate the economic dispatch of electrical systems. These results, in turn, are used to compute a projection of a facility's total annual emissions. A compliance shortfall is reached when the total number of emissions exceeds the number of allowances amassed during the early phases of the CAAA. In order to maintain compliance, either additional allowances must be purchased or the total emissions must be reduced. After the initial screening, more detailed retrofit capital cost estimates are requested from the engineering staff.

The evaluation of emission controls includes the availability of engineering staff to perform the necessary design calculations and labor forces required to construct the control. Consideration is given to the time required to complete the design of the controls. Some decisions to begin design for controls may be required before finalization of legislation and rules and resolution of associated litigation. This requires substantial research and monitoring of potential legislation and rules that might be enacted. This research considers approved or potential legislation and rules that might command the application of a control on a particular unit.

Ultimately, these technical, economic, and constructability reviews result in an overall retrofit strategy that is defined on a plant-by-plant basis. The emissions control strategy for each of Gulf Power's generating units is shown in Table 4.3-1 and defined in greater detail in Section 5 of this document. It is important to note that the formation of a retrofit strategy, and of the entire environmental strategy itself, is an iterative process that has been ongoing since the introduction of the CAAA in 1990. As such, this process can be modified to reflect changes that could influence retrofit evaluations (i.e. improvements through research, material cost, etc.).

Table 4.3-1

Projected Environmental Capital and Plant O&M Costs for CAIR, CAMR and CAVR by Project

Plant	Cumulative Capital Expenditures[a] 2007-2018 $ in Thousands	Cumulative O&M Expenses[b] 2007-2016 $ in Thousands
Plant Crist		
Mercury Monitoring	4,561	9,763
Unit 6 SCR	83,501	6,484
Units 4-7 Scrubber	527,990	55,106
Subtotal	616,052	71,353
Plant Scholz		
Mercury Monitoring	907	1,828
Subtotal	907	1,828
Plant Smith		
Unit 2 Baghouse	55,570	N/A*
Unit 1 SNCR	4,970	7,628
Unit 2 SNCR	4,970	9,540
Mercury Monitoring	1,627	3,654
Units 1-2 Scrubber	250,740	N/A*
CAIR Parametric Monitor	275	90
Subtotal	318,152	20,912
Plant Daniel[c]		
Mercury Monitoring	877	1,828
Unit 1 SCR	74,395	827
Unit 2 SCR	78,305	N/A*
Unit 1 Scrubber	92,506	10,807
Unit 2 Scrubber	94,458	10,768
Unit 1 SNCR	3,735	10,339
Unit 1 Low NO_X Burners	3,885	N/A
Unit 2 SNCR	3,770	10,339
Unit 2 Low NO_X Burners	3,921	N/A
Subtotal	355,852	44,908
TOTALS	1,290,963	139,001

a. Capital expenditures are projected through 2018 to include the total project expenditures for those projects that began during the ten year forecast period.
b. Gulf's O&M budget projection is based on a ten year forecast period.
c. Costs presented for Plant Daniel represent Gulf Power's ownership portion.
*Project will not be placed in service during the ten year forecast period.

4.3.4 Evaluation of Retrofit versus Replacement Options

Selection between retrofit and replacement options is based upon a financial assessment of which option ultimately is expected to be the most reasonable, cost-effective alternative for Gulf's customers. The analysis examines the relative cost of dispatching the Gulf system (a) with the retrofit technology in place and (b) with having retired the unit without making the retrofit and instead, replacing it with new or purchased capacity.

This analysis can be run at both a screening level and using a more detailed methodology. The basic methodology is the same for both types of analyses; however, the screening analysis employs some simplifying but more stringent assumptions. The screening level analysis uses a lower-cost replacement alternative than is used in the more detailed methodology (essentially peaking capacity with energy priced at the Southern electric system's marginal cost of energy instead of an equivalent amount of combined cycle (CC) capacity replacing the unit that would be retired). Consequently, if a retrofit option passes the more stringent screening level analysis, it will pass the more detailed analysis that uses a higher cost, site-specific replacement option. If the retrofit option fails the screening analysis, a more detailed site-specific replacement option is evaluated. The employment of this screening methodology allows a quick, yet more stringent evaluation of financial viability and is an excellent indicator of which retrofit options need a more detailed evaluation.

Methodology

The economic screening analysis creates a comparison of the costs over a period from 2006 until the current planned retirement date for each unit at which a retrofit is being contemplated. The costs of operating the retrofitted unit, its affect on system dispatch costs, and the need to purchase allowances to meet any remaining emission shortfalls (all of which are characterized as "incremental costs") are compared to the cost of a generic peaking unit and associated energy costs. To calculate those associated energy costs, Gulf assumes energy purchases from the Southern electric system at the System incremental cost. The costs associated with capacity to replace a unit and the associated energy costs are characterized as "avoided cost" as these are the costs that are avoided by operating the retrofitted unit.

The analysis compares the net present value on a $/kW basis of the two cost streams over the period analyzed to determine which has the lower cost on a net present value basis. In each instance analyzed for Gulf's units with proposed retrofit projects, continuing to operate the existing unit with the retrofit option has a net present value lower than the cost to replace the unit. The difference between the avoided cost associated with replacement and the incremental costs of operating the retrofitted unit is characterized as "the overall net contribution of continued operation." Of course, if the replacement option cost was lower than the retrofit option cost, then this value would be negative. The analyses performed for each of Gulf's units with proposed retrofit projects are summarized on Table 4.3-2.

Avoided Cost

Avoided cost includes capacity costs, energy costs, and dismantlement cost deferral. All of the costs are properly characterized as benefits, as they are the costs avoided due to operating the retrofitted unit. Avoidance of costs is a benefit to Gulf Power and its customers.

Capacity costs are the costs of a peaking generator used for system reliability to meet peak loads. Capacity costs for the replacement option in the screening analysis were based on a peaking capacity price forecast that assumes short-term purchases from the market until 2012 and the economic carrying cost of a self-build combustion turbine thereafter.

Energy costs in the screening analysis were developed using the Strategist® model. Strategist® is a production cost model commonly employed throughout both the Southern electric system and the utility industry. The avoided energy cost for each retrofitted unit was calculated by determining the average energy purchase costs during the hours the retrofitted unit operated each year. This methodology simplifies avoided energy cost calculations for use in screening potential retirement candidates.

Economic benefits associated with deferring dismantlement costs were also included in the analysis. Dismantlement cost deferred is the net savings related to avoiding the use of funds to dismantle the unit and annual increases in the cost to dismantle the unit. The dismantlement costs for each unit were obtained from engineering cost estimates.

Incremental Costs

Incremental costs include fuel, O&M, capital, and emission allowance costs (NO_X, SO_2, CO_2, and mercury) necessary for continued operation of the retrofitted facility.

The Strategist® model provided annual fuel costs and emissions costs based on the economic operation of the retrofitted unit in each scenario for the remaining life of the retrofitted generating unit. O&M costs for the retrofitted unit include labor, materials, overheads, and engineering and support services. Five-year projections of the retrofitted unit's incremental O&M costs were obtained from the 8/14/06 budget forecast. The O&M costs of the retrofitted unit over its remaining life were calculated using a moving average of the projections for the first five years and escalating the resulting value for inflation.

The incremental capital costs for the remaining life of the retrofitted unit were based on capital expenditures projected for each retrofitted generating unit. These projected capital expenditures were necessary to keep the units running through the analysis period at the current level of operation.

Summary of Study Results

Table 4.3-2 summarizes the costs and benefits of continued operation of each of the units with environmental controls over the remaining life of each unit. Assumptions for the timing and installation of environmental controls are listed at the bottom of the table. A description of each line item included in the evaluation is also included on page two of the table.

The screening level results indicate there is a savings shown by continuing to operate each generating unit as opposed to replacing it with new or purchased capacity and System energy purchases. By adding the net contribution values shown in Table 4.3-2, the NPV savings for Plants Crist, Smith and Daniel are $1.2 billion, $235 million, and $662 million, respectively. The projected NPV cost savings or benefit to Gulf and its customers for Gulf's Environmental Compliance Plan is at least $2.1 billion over the period 2006 through the affected units' planned retirement dates.

Table 4.3-2 (Page 1 of 2)
Economic Viability Study
(In $/kW)

(Actual table supplied under separate cover pursuant to request for confidential treatment)

Table 4.3-2 (Page 2 of 2)
Economic Viability Study

Generating Unit	Description
Avoided Cost Based Benefits	
Energy	The value of System lambda (marginal energy costs) during the hours the unit is running
Avoided Capacity Benefit	The projected value of peaking capacity based on the long term cost of a new CT
Decommissioning Cost Deferral	The benefit of deferring the dismantlement of a unit
Avoided Cost Benefits	Total Avoided Costs
Incremental Costs	
Fuel	The fuel cost to operate the existing unit
SO_2	The cost of SO_2 emissions based on SO_2 allowance costs and unit emissions
NO_x	The cost of NO_x emissions based on NO_x allowance costs and unit emissions
CO_2	The cost of CO_2 emissions based on CO_2 penalties and unit emissions
Hg	The cost of Hg emissions based on Hg allowance costs and unit emissions
O&M	The fixed and variable O&M costs (including environmental) to operate the unit
Capital Expenditures	The capital necessary to continue to operate and meet environmental compliance
Total	Total Incremental Costs
Net Contribution	Avoided Cost Benefits minus Incremental Costs
Environmental Control Year	
SCR	Year which environmental control is installed
Scrubber	Year which environmental control is installed
SNCR	Year which environmental control is installed

5.0 GULF'S COMPLIANCE PLAN

5.1 GULF POWER'S SYSTEM

Gulf Power owns and operates three fossil–fueled generating facilities in Northwest Florida (Plants Crist, Smith and Scholz). Gulf also owns a 50 percent undivided ownership interest in Unit 1 and Unit 2 at Mississippi Power Company's Plant Daniel. This fleet of generating units consists of ten fossil steam units, one combined cycle unit and one combustion turbine. The name plate generating capacity of Gulf's generating fleet affected by CAIR/CAMR/CAVR is 2,783 Megawatts (MW). Each plant will be affected by CAIR, CAMR and the CAVR.

A summary of the projected CAIR, CAMR, and CAVR capital projects and associated expenditures through 2018 is provided in Table 5.1-1. The projected plant O&M expenses associated with the capital projects are included in Table 5.1-2. The cost information is provided by plant and by project.

Table 5.1-1
Projected CAIR, CAMR and CAVR Capital Expenditures
$ in Thousands

(Actual table supplied under separate cover pursuant to request for confidential treatment)

Table 5.1-2
Projected CAIR, CAMR and CAVR Plant O&M Expenses
$ in Thousands

(Actual table supplied under separate cover pursuant to request for confidential treatment)

5.2 GULF POWER'S CAIR AND CAMR EMISSION REDUCTIONS

The initial step in Gulf's development of a compliance plan to meet CAIR and CAMR was to compare projected total emissions against the projected CAIR and CAMR allowance allocations. Tables 5.2-1 through 5.2-4 compare Gulf's projected emissions to projected CAIR and CAMR allowance allocations for sulfur dioxide, annual nitrogen oxides, seasonal nitrogen oxides for ozone, and mercury. In summary, Gulf is projected to have an annual shortfall of up to 58,553 SO_2 allowances, 5,443 mercury allowances, 12,952 annual NO_X allowances, and 5,598 ozone seasonal NO_X allowances, in Phase I of CAIR and CAMR. The allowance allocations decrease by an additional 17 to 61% in Phase II of CAIR and CAMR.

Table 5.2-1
Gulf's CAIR, CAMR, and CAVR Compliance Plan
Plants Crist, Scholz, Smith, and Daniel
SO_2 Emission Program

	Allocations (SO_2 Tons)	Shortfall without Controls	Shortfall with Controls	Delta (Benefit of Controls)	Control Added
2009	56,710	43,650	43,650	0	
2010	28,070	58,553	13,378	45,175	Crist FGD*
2011	28,070	52,402	(1,309)	53,711	Daniel FGD
2012	28,070	48,304	(10,296)	58,600	
2013	28,070	51,791	(10,205)	61,996	
2014	28,070	51,774	(10,551)	62,325	
2015	19,633	57,958	(4,617)	62,575	
2016	19,633	56,395	(4,533)	60,928	
2017	19,633	56,380	(6,101)	62,481	Smith FGD*

Notes: Emissions results sourced from 2007 Energy Budget.
* Crist FGD start up scheduled for December 2009. Smith FGD scheduled for startup in December 2017.

Table 5.2-2
Gulf's CAIR, CAMR, and CAVR Compliance Plan
Plants Crist, Scholz, Smith, and Daniel
Mercury Emission Program

	Allocations (Hg Ounces)	Shortfall without Controls	Shortfall with Controls	Delta (Benefit of Controls)	Control Added
2010	5,997	4,606	2,111	2,495	Crist FGD*
2011	5,997	4,559	30	4,529	Daniel FGD, Crist 6 SCR*
2012	4,871	5,012	393	4,619	
2013	4,871	5,443	540	4,903	
2014	4,871	5,426	453	4,973	
2015	4,871	5,110	128	4,982	
2016	4,871	4,933	(520)	5,453	
2017	4,871	4,985	(1,203)	6,188	Smith FGD*
2018	2,338	8,146	610	7,536	Smith 2 Baghouse

Notes: Emissions results sourced from 2007 Energy Budget.
* Crist FGD start up scheduled for December 2009. The Crist 6 SCR is projected to be completed during December 2010. Smith FGD scheduled for startup in December 2017.

Table 5.2-3
Gulf's CAIR, CAMR, and CAVR Compliance Plan
Plants Crist, Scholz, Smith, and Daniel
Annual NO_X Emission Program

	Allocations (NO_X Tons)	Shortfall without Controls	Shortfall with Controls	Delta (Benefit of Controls)	Control Added
2009	9,688	12,952	6,057	6,895	Smith SNCR, Daniel LNB
2010	9,688	12,247	5,678	6,569	Daniel 1 SNCR
2011	9,688	11,731	2,176	9,555	Crist 6 SCR*, Daniel 2 SNCR
2012	9,688	10,358	972	9,386	
2013	9,680	10,559	1,358	9,201	
2014	9,680	10,253	1,228	9,025	
2015	8,069	11,197	2,239	8,958	
2016	7,682	11,293	1,705	9,588	Daniel 1 SCR
2017	7,682	11,034	877	10,157	Daniel 2 SCR

Notes: Emissions results sourced from 2007 Energy Budget.
* The Crist 6 SCR is projected to be completed during December 2010.

Table 5.2-4
Gulf's CAIR, CAMR, and CAVR Compliance Plan
Plants Crist, Scholz, Smith, and Daniel
Ozone Seasonal NO_X Emission Program

	Allocations (NO_X Tons)	Shortfall without Controls	Shortfall with Controls	Delta (Benefit of Controls)	Control Added
2009	4,556	5,598	2,476	3,122	Smith SNCR, Daniel LNB
2010	4,556	5,255	2,266	2,989	Daniel 1 SNCR
2011	4,556	5,008	607	4,401	Crist 6 SCR*, Daniel 2 SNCR
2012	4,556	4,368	276	4,092	
2013	4,596	4,223	195	4,028	
2014	4,596	4,270	219	4,051	
2015	3,367	5,190	1,258	3,932	
2016	3,212	5,526	1,153	4,373	Daniel 1 SCR
2017	3,212	5,456	732	4,724	Daniel 2 SCR

Notes: Emissions results sourced from 2007 Energy Budget.
* The Crist 6 SCR is projected to be completed during December 2010.

5.3 GULF POWER'S COMPLIANCE OPTIONS

In order to address the projected emissions allowance shortfall, Gulf Power conducted an assessment of the various options available to assure compliance. Fuel switching, allowance purchases, emission control retrofit, and retirement and replacement were all evaluated in order to develop a cost-effective strategy for assuring compliance. Fuel switching and relying solely on allowance purchases to maintain compliance were evaluated on a company-wide basis. Emission control retrofits and retirement and replacement options were considered on a plant-by-plant basis. Ultimately, Gulf Power identified a plan that consisted of retrofits on most units with supplemental allowance purchases and either allowance purchases or retirement for two units.

5.3.1 Fuel Switching Option

Fuel switching is a compliance option to lower emissions by switching fuels. For example, SO_2 emissions can be lowered by switching to a fuel that contains less sulfur. During the 1990s, Gulf switched several plants to low-sulfur coal to achieve compliance with the Acid Rain program, and this proved to be very cost-effective for reducing emissions of SO_2.

Additional fuel switching to lower sulfur coals at Gulf's plants was considered and evaluated for compliance with the requirements of CAIR and CAMR. However, as outlined in Table 5.2-1, the magnitude of SO_2 emission reductions required by CAIR is too great to be met solely by switching to a lower sulfur coal. In addition, a switch to lower sulfur coal would not address the reduction in NO_X emissions required by the CAIR.

Fuel switching from coal to natural gas was also considered at Gulf's generating plants. However, the existing boiler designs are inefficient for firing natural gas and in some cases may trigger additional environmental controls under the New Source Review (NSR) regulation. These factors, together with the volatility in natural gas prices, make the option of switching from coal to natural gas impractical.

In summary, the use of further fuel switching at Gulf's units was eliminated as a compliance option due to practical considerations. The magnitude of SO_2 emission reductions required by CAIR is too great to be met solely through switching to a lower sulfur coal, and this switch is not likely to result in reductions in either NO_X or mercury emissions. The existing boiler designs are inefficient for firing natural gas, in some cases may trigger additional environmental controls under the New Source Review (NSR) regulation, and would expose Gulf Power and its customers to further natural gas price volatility.

5.3.2 Allowance Purchase Option

The CAIR and CAMR programs are both based on an emission allowance and market-based trading program concept. These programs set national/regional and state caps on the emissions of each pollutant (i.e., SO_2, NO_X, and mercury). Emission credits will be allocated to each state and ultimately to each generating plant in the form of emission allowances, which must be surrendered when emissions are released and can be bought and sold in the market. Gulf Power has evaluated the potential allowance market as an option for compliance based on an understanding of how the allowance market functioned under the Acid Rain Program.

The exclusive use of the allowance purchase option as the CAIR/CAMR compliance strategy was evaluated based on an understanding of how the allowance market functioned under the two previously-established and successful environmental cap and trade programs: SO_2 (acid rain) and seasonal NO_X (ozone). Although the seasonal NO_X program was implemented across most of the eastern U.S., it was not required for Florida. These existing emissions allowance markets have proven to be fundamentally driven by supply and demand. However, over time, many speculative investors have begun entering the allowance markets, particularly the SO_2 market, introducing considerable volatility and uncertainty concerning the price and availability of allowances.

In addition to reducing the number of annual SO_2 and seasonal NO_X emission credits, and thereby reducing the total number of allocated allowances, the CAIR and CAMR programs will also introduce two additional allowance markets: annual NO_X and mercury. The annual NO_X market is expected to emerge as soon as allocations are populated by the EPA. However, some utilities are emerging as sellers and presenting offers contingent upon EPA allocations that are at a significant premium to the forecast of allowance prices. The mercury allowance market presents a unique set of concerns for Gulf Power. As many as 21 states are expected to opt out of the Federal trading program. As a result, it is uncertain if a liquid market will form based on the number of utility participants. Mercury allocations are not expected to be populated for another year, creating more uncertainty regarding the availability of this commodity.

Total dependence on these commodity markets for compliance would be very risky and potentially costly for Gulf Power. Currently, there is not a mature, stable market for all the allowances that would have to be purchased in order to comply with the emission reductions required by CAIR and CAMR. Existing allowance markets show volatility, and new allowance markets are not yet established. Without more information, there is a fundamental question as to whether a sufficient volume of allowances necessary to meet an all-allowance plan would even be available, much less economical. It will take some time for the newer allowance markets to emerge and stabilize, and given the timing of construction schedules and the 2009-2010 compliance deadlines for the new rules, Gulf Power cannot wait to determine if stable allowance markets will emerge. Although the market may provide realistic opportunities for reducing costs through selected and limited purchases of allowances in conjunction with other options to achieve cost-effective compliance, the volatility of the allowance markets, the lack of existing allowance markets for newly regulated emissions, and the overall uncertainties regarding the cost and availability of allowances eliminated an all-allowance purchase option from consideration as a compliance strategy.

5.3.3 Retrofit Controls and Retirement and Replacement Options

After elimination of the fuel switching option and exclusive reliance on the allowance purchase option, Gulf evaluated retrofit controls and retirement and replacement options on a plant-by-plant basis. Section 5.4 discusses these plant-specific options in greater detail.

5.4 PLANT-BY-PLANT COMPLIANCE PLAN

5.4.1 Plant Crist

Plant Crist is a four-unit, coal-fired electric generating facility located just north of Pensacola, Florida. Three older natural gas and oil-fired units at the site have been retired. Units 4 and 5 are rated (nameplate) at 93.7 MW each, Unit 6 is rated (nameplate) at 369

MW, and Unit 7 is rated (nameplate) at 578 MW. All four units were affected under the Acid Rain Program, and the plant has operated on low-sulfur coals since the 1990s to lower SO_2 emissions. All four units are equipped with low-NO_X burner systems. Plant Crist Units 4, 5 and 6 have SNCR systems, while Crist Unit 7 is equipped with a SCR system.

For compliance with CAIR and CAMR, and later with CAVR, Plant Crist needs significant SO_2 reductions, mercury reductions, and additional NO_X reductions. For instance, in the first year of Phase I, Gulf Power forecasts that without emission controls Plant Crist would exceed allowance allocations by 34,388 tons for SO_2, 3,668 tons for NO_X and 2,599 ounces for mercury. Only a few technologies have demonstrated the ability to provide the needed emission reductions at the commercial scale required for Plant Crist.

For CAIR and CAMR requirements at Plant Crist, a thorough assessment was conducted to compare the retrofit controls versus retirement and replacement options for compliance. As noted under Sections 5.3.1 and 5.3.2, fuel switching and exclusive reliance on allowance purchases were eliminated as viable options for Gulf Power. Retrofit options, as well as retirement and replacement options, are each reviewed below specifically for Plant Crist.

5.4.1.1 Plant Crist Retrofit Options

Plant Crist Units 4 through 7 Flue Gas Desulfurization Scrubber Project

Very high levels of SO_2 emission reductions can be achieved by flue gas desulfurization. There are no other commercially available options for SO_2 emission reductions at the level needed to assure compliance with CAIR, CAMR, and CAVR and address the significant local concerns in the Pensacola area.

A scrubber was determined to be the only SO_2 retrofit compliance option for Plant Crist Units 6 and 7. Crist Units 6 and 7 represent Gulf Power's largest coal-fired generating units and emit the most SO_2 and mercury emissions from the Gulf Power fleet. Because of the size and potential for emission reductions, these units were found to be the most cost-effective units for SO_2 scrubbing and mercury removal. Increasing the scrubber vessel size to include Crist Units 4 and 5 was shown to save costs in achieving incremental SO_2 and mercury reductions from these units.

Chiyoda scrubber technology was chosen for Crist Units 4 through 7 based on the specific circumstances and requirements at Plant Crist. Both Chiyoda and Advatech technologies are capable of achieving the required SO_2 removal rates of 98 percent; however, with the four-units-on-one-scrubber design, the Chiyoda technology offers better performance over a wider range of possible operating conditions, while also maintaining a high particulate removal performance. The Chiyoda technology is less sensitive to load fluctuations and allows for higher sulfur fuels to be burned than the Advatech technology. This was a critical consideration at Plant Crist, as the inlet flow distribution to the scrubber would be extremely variable as four units come up and down on load. The Advatech technology is better suited to more stable inlet flows that are associated with a base-loaded generating unit or units. The removal of SO_3 is also of critical importance at Plant Crist and directly correlates to coal sulfur content and to the operation of the SCRs on Units 6 and 7. Increased stack SO_3 concentrations can lead to increased acid aerosol emissions, and the Chiyoda technology provides the potential for higher SO_3 removal rates relative to Advatech scrubbers. The Chiyoda design provides a wide pH operating range, offering greater control flexibility with the limestone reagent and the ability to minimize chemical reaction threats to SO_2 removal effectiveness, such as aluminum fluoride blinding.

The Crist scrubber project is projected to reduce SO_2 emissions by approximately 43,000 tons per year and mercury emissions by about 3,800 ounces per year. With these reductions, Gulf Power will be able to reasonably manage compliance with its allowance bank and some market purchases of allowances as required.

In terms of timing, the Crist scrubber is needed for Phase I CAIR and CAMR compliance in 2010. This plan focuses on placing this scrubber on the largest Gulf Power generating units first and delaying emission controls and costs on other smaller units and plants.

Plant Crist Unit 6 SCR Project

The Plant Crist Unit 7 SCR became operational in 2005, significantly reducing emissions of NO_X from the plant. This project was called for under an agreement with the FDEP. The agreement also called for additional NO_X reductions at Plant Crist Units 4 through 6 up to and including a SCR for Unit 6. Additional NO_X reductions are needed at Plant Crist, and only SCR technology will provide the additional increment needed. The SCR is also important to assure that Pensacola maintains attainment with the new stringent 8-hour ozone standard and addresses significant local pressures to continue NO_X reductions from the plant. In addition, the SCR will assure compliance with CAIR. This SCR, along with the existing Crist Unit 7 SCR and the Crist scrubber, is also needed to maximize mercury reductions and compliance with CAMR.

5.4.1.2 Plant Crist Comparison of Retrofit versus Retirement and Replacement

Selection between retrofit and retire/replacement options for Plant Crist is based upon a financial assessment and analysis to determine the most reasonable, least cost option for Gulf Power and its customers. The analysis examines the relative cost of dispatching the Gulf system (a) with the retrofit technology in place and (b) with having retired the Crist unit(s) without making the retrofit and instead, replacing it with capacity from another generation source.

An economic screening analysis was performed to assess the costs over a period from 2006 until the current planned retirement date for each of the four Plant Crist units. The costs of operating the retrofitted units and its affect on system dispatch costs and the need to purchase allowances to meet any remaining emissions (all of which are characterized as "incremental costs") were compared to the cost of a generic peaking unit and associated energy costs.

The results of the analysis indicated there was a savings associated with retrofits and continuing to operate each generating unit at Plant Crist, as opposed to replacing the generation. The projected NPV cost savings or benefit to Gulf and its customers for Gulf's Environmental Compliance Plan at Plant Crist is at least $1.2 billion over the period 2006 through the planned retirement dates for Units 4 through 7.

5.4.1.3 Plant Crist Emission Monitoring Requirements

CAIR will require a continuous emission monitoring system on the Plant Crist scrubber. CAMR will require continuous emission monitoring of mercury emissions at all of the Plant Crist units as well as the scrubber. These monitoring systems will be subject to rigorous quality assurance measures to ensure accurate accounting of mercury emissions. This approach will help ensure accuracy and consistency and will contribute to the most reasonable, cost-effective overall compliance strategy for the CAMR. Because mercury has never before been monitored at these levels and in this manner, issues regarding the monitoring, certification, quality assurance and reference testing of mercury continue to be investigated.

In January 2007, Gulf Power submitted a petition to EPA and FDEP asking for an extension of the January 1, 2009, deadline for installation of mercury monitors on the existing stacks at Plant Crist until after the scrubber system is completed later in 2009. The new scrubber stack will become the official mercury monitoring compliance location for Plant Crist. The granting of this petition submitted to EPA and FDEP would basically eliminate the need for the plant to install four mercury monitoring systems that would otherwise only operate in 2009.

5.4.1.4 Conclusions for Plant Crist

Based on this assessment, the retrofit of Crist Units 4 through 7 with a single flue gas desulfurization scrubber and the addition of a SCR at Unit 6 are the best options for compliance with CAIR, CAMR, and CAVR at Plant Crist. These are the only technologies that offer the necessary emission reductions for SO_2 and NO_X and when used together, the scrubber and the SCRs on Units 6 and 7 will capture mercury. Further fuel switching will not reduce emissions to the required level. Allowance purchases are too uncertain and risky as a sole compliance option, especially for annual NO_X and mercury. Retirement and replacement of the units is not economical relative to retrofit of the existing units. The scrubber is expected to be required as part of the CAVR "reasonable progress program."

5.4.2 Plant Daniel

Gulf Power's ownership interest at Plant Daniel is associated with two 548.2-MW (nameplate), New Source Performance Standard (NSPS), coal-fired electric generating units. Gulf Power and Mississippi Power Company each own 50 percent of Daniel Units 1 and 2. The plant is operated by Mississippi Power employees. The facility is located just north of Pascagoula, Mississippi, with direct transmission access across Alabama and into Florida. Both coal-fired units were affected under the Acid Rain Program and have operated on low-sulfur coals since the 1990s to lower SO_2 emissions. These NSPS units are relatively low NO_X emitters, and as a result, Gulf and Mississippi Power have been able to delay installation of controls and associated costs required under the Acid Rain Program.

For compliance with CAIR and CAMR, and later with CAVR, Plant Daniel Units 1 and 2 need significant SO_2 reductions, mercury reductions, and additional NO_X reductions. Only a few technologies have demonstrated the ability to provide the needed emission reductions at the commercial scale required for the coal units at Plant Daniel.

For CAIR, CAMR, and CAVR requirements at Plant Daniel Units 1 and 2, an assessment was conducted to compare retrofit controls versus retirement and exclusive reliance on replacement options for compliance. As noted under Sections 5.3.1 and 5.3.2, further fuel switching and complete reliance on allowance purchases were eliminated as viable options for all of Gulf Power's units, including its share of Plant Daniel Units 1 and 2. Retrofit options and retirement and replacement options are each reviewed below specifically for Plant Daniel.

5.4.2.1 Plant Daniel Retrofit Options

Plant Daniel Unit 1 and Unit 2 Flue Gas Desulfurization Scrubber Project

Very high levels of SO_2 emission reductions can be achieved by flue gas desulfurization. There are no other commercially available options for SO_2 emission reductions at the level needed to assure compliance with CAIR, CAMR, and CAVR and address the significant local concerns along the Mississippi Gulf Coast.

The Plant Daniel Unit 1 and Unit 2 scrubber is needed to meet the requirements of CAIR, CAMR and CAVR. These large, co-owned units are early in the Southern electric system dispatch order, meaning that they are relatively economic to operate and generate consistently. A wet scrubber has been determined to be the only viable SO_2 retrofit compliance option for Plant Daniel.

The Daniel scrubber project is projected to reduce Gulf's SO_2 emissions by approximately 18,000 tons per year and mercury emissions by about 2,000 ounces per year (Gulf Power ownership share). With these reductions, Gulf Power will be able to reasonably manage compliance with its allowance bank and some market purchases of allowances as required.

The single tower Advatech technology was chosen for Plant Daniel Units 1 and 2 primarily due to the operational characteristics of those units and the low-sulfur fuels expected to be burned at the plant. The Advatech technology is well suited to the stable inlet flow distribution that is characteristic of base-loaded generating units such as Plant Daniel Units 1 and 2. Additionally, Plant Daniel's fuel basis is 0.3 to $\leq$ 1.5 percent sulfur coal. By using a single tower Advatech scrubber, higher-cost oxidation air blowers can be eliminated and a lower-cost jet air sparger system can be installed, which provides additional capital savings and reduces O&M costs. Finally, since Plant Daniel will be burning low-sulfur fuel due to new source performance requirements and will be installing SCRs at a later date for Phase II, no issues are anticipated with visible acid aerosols (SO_3) plumes. For these reasons, the single tower Advatech scrubber provides the most reasonable and economical approach for meeting the environmental requirements for Plant Daniel.

For CAIR, the scrubber will minimize the reliance on a very volatile SO_2 allowance market and assure compliance for Plant Daniel Units 1 and 2. When SCRs are installed at these units, co-benefits in mercury emission reductions from SCRs and the scrubber of about 80 percent will be realized.

Plant Daniel SNCR and NO_X Reduction Projects

SNCR and additional combustion NO_X controls are currently planned for Plant Daniel Units 1 and 2 under the Phase I CAIR annual and seasonal NO_X cap and trade allowance programs. In addition, NO_X reductions from these projects would help in maintaining local compliance with the 8-hour ozone standard.

Plant Daniel Unit 1 and 2 SCR Projects

The Plant Daniel Units 1 and 2 SCRs are planned for operation in 2016 and 2017, respectively, to help meet the requirements of CAIR, CAMR, and possible 8-hour ozone nonattainment. These SCRs, along with the Unit 1 and 2 scrubber, provide a co-benefit of significantly reducing mercury emissions to help meet the very stringent requirements of the Phase II CAMR. The schedule for these proposed SCRs remains flexible.

5.4.2.2 Plant Daniel Comparison of Retrofit versus Retirement and Replacement

Selection between retrofit and retirement/replacement options for Plant Daniel is based upon a financial assessment and analysis to determine the least cost option for Gulf Power and its customers. The analysis examines the relative cost of dispatching the Gulf system (a) with the retrofit technology in place and (b) with having retired the Daniel unit(s) without making the retrofit and instead, replacing it with capacity from another generation source.

An economic screening analysis was performed to assess the costs over a period from 2006 until the current planned retirement date for each of the Plant Daniel units. The costs of operating the retrofitted units and its affect on system dispatch costs and the need to purchase allowances to meet any remaining emissions (all of which are characterized as "incremental costs") were compared to the cost of a generic peaking unit and associated energy costs.

The results of the analysis indicated there was a savings associated with retrofits and continuing to operate each generating unit at Plant Daniel, as opposed to replacing the generation. The projected NPV cost savings or benefit to Gulf and its customers for Gulf's Environmental Compliance Plan at Plant Daniel is at least $662 million over the period 2006 through the planned retirement dates for Units 1 and 2.

5.4.2.3 Plant Daniel Emission Monitoring Requirements

CAIR will require a continuous emission monitoring system on the Plant Daniel scrubber. CAMR will require continuous emission monitoring of mercury emissions at all of Plant Daniel's coal fired units and the scrubber. These monitoring systems will be subject to rigorous quality assurance measures to ensure accurate accounting of mercury emissions. This approach will help ensure accuracy and consistency and will contribute to the most reasonable, cost-effective overall compliance strategy for the CAMR. Because mercury has never before been monitored at these levels and in this manner, issues regarding the monitoring, certification, quality assurance and reference testing of mercury continue to be investigated.

5.4.2.4 Conclusions for Plant Daniel

Based on this assessment, the retrofit of Daniel Units 1 and 2 with an Advatech single-tower, flue gas desulfurization scrubber, the installation of SNCR and other low-NO_X combustion controls, and later the addition of SCRs on both units are the best options for compliance with CAIR, CAMR, and CAVR at Plant Daniel. These technologies offer the necessary emission reductions for SO_2 and NO_X. After the SCRs are installed and the scrubber is operating, mercury capture of 80 percent should be possible for CAMR Phase II. Fuel switching will not reduce emissions to the required level. Allowance purchases are too uncertain and risky as a sole compliance option, especially for annual NO_X and mercury. Retirement and replacement of the units is not economic relative to retrofit of the existing units. The scrubber is also expected to be required as part of the CAVR "reasonable progress program."

5.4.3 Plant Smith

Plant Smith includes two coal-fired electric generating units (Unit 1 and Unit 2) along with an oil-fired combustion turbine and a natural gas-fired combined cycle unit. The facility is located just north of Panama City, Florida. Plant Smith Unit 1 is rated (nameplate) at 149.6 MW and Unit 2 is rated (nameplate) at 190.4 MW. Both coal-fired units were affected under the Acid Rain Program and the plant has operated on low-sulfur coals since the 1990s to lower SO_2 emissions. Both units are also equipped with low-NO_X combustion systems. Unit 1 has special low-NOx burner tips, and Unit 2 has low-NO_X burners and separated overfired air.

For compliance with CAIR and CAMR, and later with CAVR, Plant Smith needs significant SO_2 reductions, mercury reductions, and additional NO_X reductions. Only a few technologies have demonstrated the ability to provide the needed emission reductions at the commercial scale required for Plant Smith.

For CAIR, CAMR, and CAVR requirements at Plant Smith, an assessment was conducted to compare retrofit controls versus retirement and replacement options for compliance. As noted under Sections 5.3.1 and 5.3.2, fuel switching and exclusive reliance on allowance purchases were eliminated as viable options for Gulf Power. Retrofit options and retirement and replacement options are each reviewed below specifically for Plant Smith.

5.4.3.1 Plant Smith Retrofit Options

Plant Smith SNCR and NO_X Reduction Projects

SNCR is currently planned for Plant Smith Units 1 and 2 under the Phase I CAIR annual and seasonal NO_X cap and trade allowance programs. In addition, NO_X reductions from these projects would help in maintaining local compliance with the 8-hour ozone standard.

Plant Smith Units 1 and 2 Flue Gas Desulfurization Scrubber Project

The Plant Smith scrubber project has been included in the Gulf Power Environmental Compliance Plan because the requirements of CAVR will likely lead to a scrubber being required for Plant Smith Units 1 and 2. This decision is based upon anticipated CAVR command and control requirements. In addition, the scrubber will provide a co-benefit of reducing Phase II CAIR and CAMR shortfalls. The scrubber project is currently planned for operation in 2017. This schedule and decisions about the Plant Smith scrubber remain very flexible. This scrubber would offer the same benefits as the scrubbers discussed above for Plants Crist and Daniel.

Plant Smith Unit 2 Baghouse

The Plant Smith Unit 2 baghouse project has been included in the Gulf Power Environmental Compliance Plan because the Phase II requirements of CAMR will likely lead to a baghouse being required for Plant Smith. The baghouse project is currently planned for operation in 2018. The schedule and decisions about the Plant Smith baghouse remain very flexible.

5.4.3.2 Plant Smith Comparison of Retrofit versus Retirement and Replacement

Selection between retrofit and retirement/replacement options for Plant Smith is based upon a financial assessment and analysis to determine the least cost option for Gulf Power and its customers. The analysis examines the relative cost of dispatching the Gulf system (a) with the retrofit technology in place and (b) with having retired the Smith unit(s) without making the retrofit and instead, replacing it with capacity from another generation source.

An economic screening analysis was performed to assess the costs over a period from 2006 until the current planned retirement date for the two coal-fired Plant Smith units. The costs of operating the retrofitted units and its affect on system dispatch costs and the need to purchase allowances to meet any remaining emissions (all of which are characterized as "incremental costs") were compared to the cost of a generic peaking unit and associated energy costs.

The results of the analysis indicated there was a savings associated with retrofits and continuing to operate each generating unit at Plant Smith, as opposed to replacing the generation. The projected NPV cost savings or benefit to Gulf and its customers for Gulf's Environmental Compliance Plan at Plant Smith is at least $235 million over the period 2006 through the planned retirement dates for Units 1 and 2.

5.4.3.3 Plant Smith Emission Monitoring Requirements

CAIR will require a parametric emission monitoring system on the Plant Smith combustion turbine. Additionally, CAIR will require a continuous emission monitoring system on the Plant Smith scrubber. CAMR will require continuous emission monitoring of mercury emissions at all of the Plant Smith coal-fired units and the scrubber. These monitoring systems will be subject to rigorous quality assurance measures to ensure accurate accounting of mercury emissions. This approach will help ensure accuracy and consistency and will contribute to the most cost-effective overall compliance strategy for the CAMR. Because mercury has never before been monitored at these levels and in this manner, issues regarding the monitoring, certification, quality assurance and reference testing of mercury continue to be investigated.

5.4.3.4 Conclusions for Plant Smith

Based on this assessment, the retrofit of Smith Units 1 and 2 with SNCR, a flue gas desulfurization scrubber, and a baghouse are the best options for compliance with CAIR, CAMR, and CAVR at Plant Smith. These technologies offer the necessary emission reductions for SO_2, NO_X, and mercury. Fuel switching will not reduce emissions to the required level. Allowance purchases are too uncertain and risky as a sole compliance option, especially for annual NO_X and mercury. Retirement and replacement of the units is not economic relative to retrofit of the existing units. The scrubber is also expected to be required as part of the CAVR "reasonable progress program."

5.4.4 Plant Scholz

Plant Scholz consists of two coal-fired electric generating units rated (nameplate) at 49 MW each. The facility is located in Jackson County, Florida. Both units were affected under the Acid Rain Program, and the plant has operated on low-sulfur coals since the 1990s to lower SO_2 emissions. Because these units are small and older, NO_X averaging was used to achieve compliance with the NO_X requirements under the Acid Rain Program without the installation of emission control equipment.

For CAIR, CAMR, and CAVR requirements at Plant Scholz, a thorough assessment was conducted to compare retrofit controls versus retirement and replacement options for compliance. As noted under Sections 5.3.1 and 5.3.2, fuel switching and exclusive reliance on allowance purchases were eliminated as viable options for Gulf Power. Because this small plant is nearing retirement, significant investments in capital equipment to reduce emissions cannot be justified economically. The plant will utilize Company-wide allowance trading options to comply up until the retirement of both units.

5.4.4.1 Plant Scholz Emission Monitoring Requirements

CAMR will require continuous emission monitoring of mercury emissions at the plant and will be subject to rigorous quality assurance measures to ensure accurate accounting of mercury emissions. This approach will help ensure accuracy and consistency and will contribute to the most cost-effective overall compliance strategy for the CAMR. Because mercury has never before been monitored at these levels and in this manner, issues regarding the monitoring, certification, quality assurance and reference testing of mercury continue to be investigated.

5.4.4.2 Conclusions for Plant Scholz

For CAIR, CAMR, and CAVR requirements at Plant Scholz, a thorough assessment was conducted to compare the various options for compliance. CAMR will require continuous emission monitoring of mercury emissions at the plant as well as rigorous quality assurance measures to ensure accurate accounting of mercury emissions. Fuel switching, allowance purchases, and emission control retrofit versus retirement and replacement were all evaluated as options for compliance. The plant will utilize Company-wide allowance trading options to comply until it is retired.

5.5 GULF'S ALLOWANCE PURCHASES

Although the retrofit installations set forth above in Gulf's Compliance Plan significantly reduce emissions, they will not result in Gulf achieving CAIR and CAMR compliance levels without the purchase of some emission allowances. Thus, Gulf's Environmental Compliance Plan calls for the purchase of allowances. The emission allowances Gulf Power projects it needs to purchase, along with estimated costs, are shown in Table 5.5-1. These represent the shortfall in emission allowances that Gulf projected when it compared its retrofit options to retirement and replacement options. Therefore, they have been captured in the economic analyses and found to be cost-effective. The purchase of these options in conjunction with the retrofit projects comprises the most reasonable, cost-effective means for Gulf to meet CAIR, CAMR and CAVR requirements.

Table 5.5-1
Gulf Power Allowance Projection and Costs
(2009-2017)

(Actual table supplied under separate cover pursuant to request for confidential treatment)

5.6 SUMMARY OF GULF'S COMPLIANCE PLAN

Gulf Power's Environmental Compliance Plan reflects a comprehensive assessment of requirements Gulf and its customers face in meeting CAIR, CAMR and CAVR requirements. The CAIR and CAMR regulatory regimes will require significant reductions in SO_2, NO_X and mercury. CAVR may also require the installation of command and control retrofit equipment at certain facilities. In assessing the most cost-effective means of meeting these significant regulatory requirements, Gulf Power considered four primary compliance options: fuel switching, purchase of allowances, retrofit installations, and retirement and replacement of existing units. Fuel switching alone could not meet the requirements of these programs. Given the uncertainty of emerging allowance markets, it was highly questionable whether mature stable allowance markets would emerge in time for an all allowance purchase option to be implemented. There was a fundamental question of whether sufficient allowances would even be available. In addition, given the historic volatility in existing allowance markets, the potential cost of an all-allowance option could be significant. Therefore, risks regarding availability and costs of allowances resulted in an unacceptable level of risk for an all-allowance compliance approach for Gulf and its customers. As a result, Gulf assessed the best means of meeting plant-by-plant emission requirements through retrofit measures supplemented by allowance purchases and compared those options to retiring and replacing existing units. That analysis led to the selection of Gulf Power's Environmental Compliance Plan set forth in Table 4.3-1. Gulf Power's Environmental Compliance Plan, which is based upon analytically sound technical and economic evaluations of alternatives, is the most reasonable, cost effective compliance plan available to Gulf and its customers under current planning assumptions. Gulf Power's Environmental Compliance Plan assures environmental compliance and preserves flexibility for dealing with ever changing requirements and assumptions.

APPENDIX A

Background Information
on
Environmental Requirements

APPENDIX A

BACKGROUND INFORMATION ON ENVIRONMENTAL REQUIREMENTS

A.1 ACID RAIN REQUIREMENTS

Phase I of the acid rain requirements of the Clean Air Act Amendments (CAAA) became effective for sulfur dioxide (SO_2) on January 1, 1995. The Environmental Protection Agency (EPA) allocated SO_2 allowances to Phase I units on an average-baseline heat input (for the years 1985-1987) and an allocation factor of 2.5 lbs of SO_2/MBtu. Phase I required that each named unit (Crist Units 6 and 7 for Gulf Power) have sufficient allowances in its unit account to cover the SO_2 emissions for each year.

Due to the litigation of the final rules, the effective date for Phase I nitrogen oxide (NO_X) compliance under the requirements was delayed until January 1, 1996. Beginning in 1996, annual NO_X emission rates were met, individually or on average, by all coal-burning Phase I dry-bottom, wall-fired, and tangentially fired boilers. The Phase I limits were 0.50 and 0.45 lbs/MBtu, respectively. The limits for units named under Phase I and units substituted into Phase I are higher than required for Phase II.

Phase II of the acid rain requirements of the CAAA became effective on January 1, 2000. The EPA allocated SO_2 emission allowances to all steam generating units above 25 MW in size (again based on 1985-1987 heat input) with an allocation factor of 1.2 lbs of SO_2/MBtu. Phase II affected Crist Units 4 through 7, Scholz Units 1 and 2, and Smith Units 1 and 2.

Phase II NO_X requirements also became effective on January 1, 2000. The final Phase II NO_X rules set the limits for the three general boiler and burner types and designs at 0.46 lbs/MBtu for wall-fired boilers, 0.40 lb/MBtu for tangentially fired boilers, and 0.68 lbs/MBtu for the difficult-to-control cell burners. Gulf Power owns and operates wall-fired and tangentially fired boilers.

A.2 AMBIENT AIR QUALITY STANDARDS

The cornerstone of the Clean Air Act is attainment of the National Ambient Air Quality Standards (NAAQS) for the following six pollutants:

- Carbon monoxide
- Sulfur dioxide (SO_2)

- Nitrogen dioxide (NO_2)
- Ozone
- Lead
- Particulate matter

The most pervasive and difficult pollutant to reduce continues to be ozone, with many major urban areas, including Pensacola, continuing to remain concerned with maintaining attainment with these standards. NO_X emissions from coal-fired power plants, especially in or near urban areas such as Plant Crist near Pensacola and Plant Smith near Panama City, are a precursor to the formation of ozone in the atmosphere when other constituents are present and conditions are right.

EPA sets the ambient standards at levels requisite to protect public health with an adequate margin of safety. The states then develop State Implementation Plans (SIPs) which set forth state-specific requirements for bringing areas of the state that do not achieve the ambient standard (known as nonattainment areas) into compliance with the standard. All areas in Florida are currently in attainment with the ozone standard.

A.2.1 Ozone

Many major urban areas across the U.S., but none in Florida, were designated as nonattainment for the original ozone standard – which was based on a 1-hour averaging time for many years. In 1997, EPA adopted a new standard based on an 8-hour averaging time. On April 15, 2004, the EPA issued final rules to implement the 8-hour ozone standard (see Section A.2.2 below) and also provided for the June 15, 2005, revocation of the 1-hour standard. In addition, compliance requirements related to ozone are continuing to evolve through CAIR and other control strategies for attaining the new 8-hour ozone standard.

In the fall of 2002, the Florida Department of Environmental Protection (FPEP) entered into an agreement with Gulf Power to help lower ozone levels in the Pensacola area by installing NO_X emission control technology at Plant Crist. Among other things, the agreement specified:

- Installation of SCR technology on Crist 7 by May 1, 2005
- Completion of an engineering feasibility study addressing NO_X reduction technologies on Crist Units 4, 5, and/or 6 to achieve a 0.2 lbs/mmbtu emission limit by May 1, 2005

- Implementation of emission reduction activities on Crist Units 4, 5, and/or 6 by May 1, 2006

A.2.2 New 8-Hour Ozone Standard

On July 18, 1997, the EPA promulgated new ambient air quality standards for ozone and fine particulate matter (Section A.2.3). Compared with the older ozone standard, the new ozone standard has a lower ozone concentration level (0.08 ppm versus 0.12 ppm) and a longer averaging period (8 hours versus 1 hour). The two standards also use different calculation methods. The net effect of the changes is a more stringent standard. Attainment of the 8-hour standard is determined with a calculation involving the average fourth-highest concentration averaged over a 3-year period.

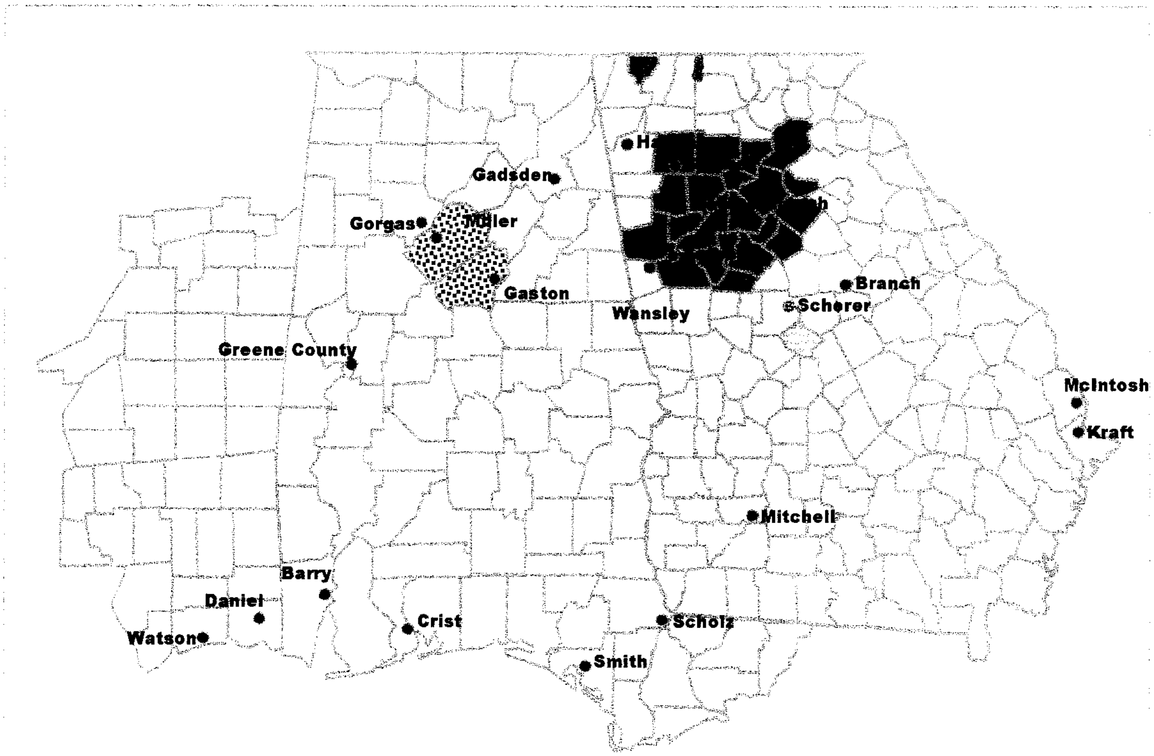
In April of 2004, EPA issued final rules addressing classification of nonattainment areas, transition from the 1-hour to the 8-hour standard, and revocation of the 1-hour standard. In a subsequent notice, EPA has issued rules regarding Rate-of-Progress and NO_X-for-volatile organic compound substitution. EPA designated nonattainment areas for the 8-hour ozone standard on April 15, 2004. Figure A.2-1 shows the final EPA 8-hour ozone nonattainment designations for areas just north of Gulf Power's service area.

For areas designated nonattainment, SIPs containing attainment demonstrations and control requirements will be required from the states in June 2007. However, on December 22, 2006, the D.C. Circuit court vacated the Phase I implementation rules upon which these designations were based and subsequent proceedings may result in an extension of this deadline.

EPA's CAIR (see Section 2.1) mandates large NO_X reductions to reduce the transport of these emissions across the eastern U.S. EPA anticipates adoption of CAIR will lower ozone levels across the eastern U.S. and bring many areas into attainment with the ozone standard without additional new control requirements. SIPs to implement the CAIR were due in September 2006, before SIPs for nonattainment areas were due.

Figure A.2-1

Final EPA 8-Hour Ozone Nonattainment Designations in the Southern Company Service Area



Nonattainment areas.

Areas that have demonstrated attainment.

Areas redesignated as attainment by EPA.

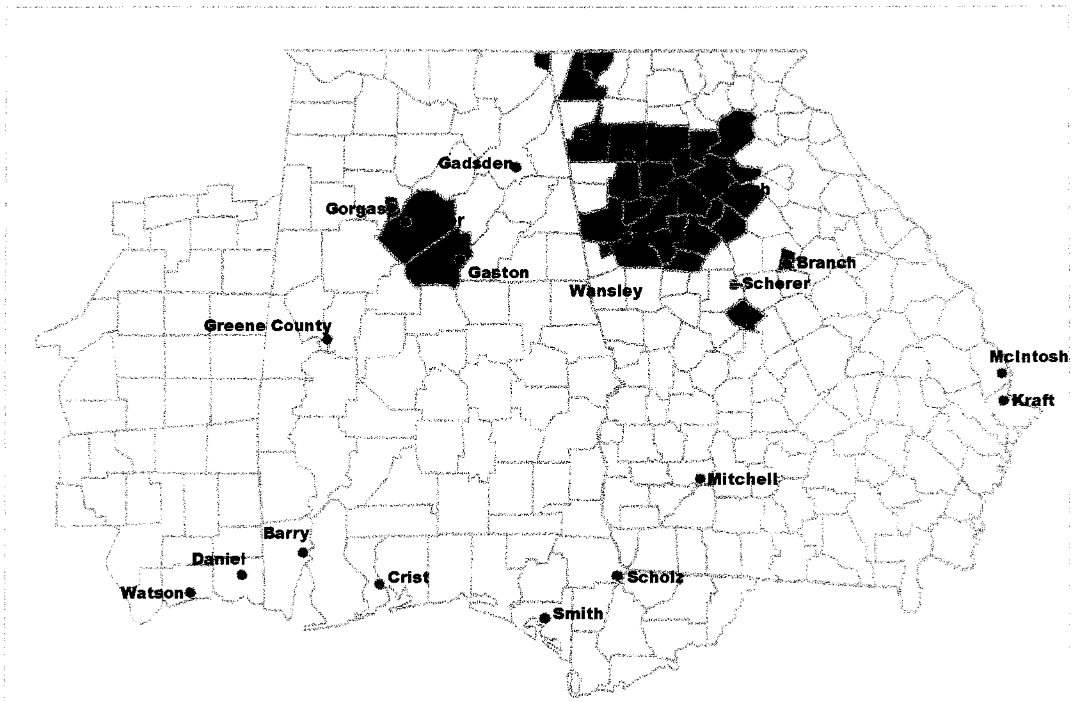
A.2.3 New Fine Particle Standard

On July 18, 1997, the EPA promulgated a new ambient air quality standard for fine particles less than 2.5 micrometers in size (PM-2.5). The new standards included an annual primary standard of 15 $\mu g/m^3$ and a 24-hour standard of 65 $\mu g/m^3$. The new fine particulate standard was challenged in the courts and delayed, but was largely upheld by the D.C. Circuit Court of Appeals and the U.S. Supreme Court.

The states initially recommended PM-2.5 designations in February 2004; EPA responded to these recommendations in June 2004. After considering additional state information, EPA issued final designations on December 17, 2004. The counties within the Southern Company service area and north of Gulf Power that were designated as nonattainment are shown in Figure A.2-2. State SIPs are due in April 2008. However, the control strategy provisions of those SIPs will be affected by adoption of CAIR that was issued by EPA in March 2005 (see Section 2.1) to address interstate transport of SO_2 and NO_X emissions which significantly contribute to particulate matter (PM) and ozone nonattainment areas.

Figure A.2-2

Final EPA PM-2.5 Nonattainment Designations (1997 Standard) in the Southern Company Service Area



In September 2006, EPA promulgated final revisions to its new PM-2.5 standard. EPA retained the primary annual standard of 15μg/m^3, but reduced the 24-hour standard from 65 to 35 μg/m^3. It is expected that this more stringent 24-hour standard will result in additional nonattainment areas in the Southern Company's service area. State recommendations of nonattainment areas for the revised standards will be due in November 2007. EPA will approve or disapprove of the new nonattainment areas by November 2009 and SIPs will be due in 2013. Both environmental groups and industry have challenged the new PM standards in the D.C. Circuit Court of Appeals.

A.3 WASTE WATER TREATMENT ISSUES

Since the Clean Water Act (CWA) was initially authorized by Congress in 1972, it has been revised and updated several times. In recent years, the EPA has unveiled several regulatory and legislative initiatives to expand clean water programs and further amend the CWA, and the agency currently has underway a number of significant water initiatives that impact Gulf Power. The implications for water discharges from units equipped with flue gas desulfurization and/or mercury controls could be significant.

The air pollution control technologies utilized to meet the requirements of the CAIR and CAMR remove not only SO_2 and NO_X from the flue gas but also other volatile constituents, such as arsenic, selenium, cadmium, and mercury. These constituents could potentially end up in the plant's wastewater streams and eventually discharged into waters of the State. Wastewater treatment systems could be required to meet the State's water quality standards which protect the water quality of rivers and streams in Florida.

Florida's surface water quality standards include numeric water quality limitations, toxicity requirements (chronic and acute), as well as narrative statements for fresh waters and estuaries. These standards can be found in 62-302 and 62-302.530 of the Florida Administration Code. These water quality standards, established by Florida to protect the designated uses of waters of the State, restrict quantities, rates or concentrations of chemical, physical, biological, or other constituents discharged from point sources. In addition to these standards, the State of Florida's antidegradation policies require abatement of water pollution whenever attainable to protect fish, shellfish, and wildlife, as well as for recreation in and on the water.

A.4 LAND ISSUES - GYPSUM DISPOSAL AND OTHER REQUIREMENTS

Fossil fuel combustion products, including coal combustion ash and flue gas desulfurization gypsum, are currently exempt from the EPA hazardous waste regulations by virtue of the Bevill Amendment to the Resource Conservation and Recovery Act (RCRA). Based upon approximately 20 years of scientific studies, EPA confirmed in April 2000 that fossil fuel combustion products do not warrant regulation as a hazardous waste. Gypsum is considered a coal combustion product and as a result will require a landfill to be constructed for any gypsum not sold or used for beneficial re-use. A groundwater monitoring plan and sampling will be required along with periodic monitoring of the landfill and associated ponds. In addition, there will be closure and post closure care required for this facility.

APPENDIX B

Acronyms/Abbreviations and Terminology

APPENDIX B

ACRONYMS/ABBREVIATIONS AND TERMINOLOGY

CAAA	Clean Air Act Amendments (of 1990)
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CC	Combined Cycle
CT	Combustion Turbine
CWA	Clean Water Act
EPA	Environmental Protection Agency
FDEP	Florida Department of Environmental Protection
FGD	Flue Gas Desulfurization
Hg	Mercury
LNB	Low-NO_X Burner
NAAQS	National Ambient Air Quality Standards
MW	Megawatts
NH_3	Ammonia
NO_X	Nitrogen Oxide

NSPS	New Source Performance Standard
O&M	Operations and Maintenance
OFA	Overfire Air
PM	Particulate Matter
PM-2.5	Particulate Matter less than 2.5 micrometers in size
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Noncatalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SOFA	Separated Overfire Air
VCCOFA	Vane Closed-Coupled Overfire Air

APPENDIX C

Emission Control Alternatives

APPENDIX C

EMISSION CONTROL ALTERNATIVES

APPENDIX C

C.1 NO_X EMISSION CONTROL ALTERNATIVES

C.1.1 Selective Catalytic Reduction (SCR)

SCR technology involves the catalytic reaction of ammonia (NH_3), which is injected into the flue gas, with NO_X to produce molecular nitrogen (N_2) and water vapor. These reactions take place across multiple layers of catalyst in the SCR reactor and generally result in a NO_X reduction capability of 85 to 90 percent depending upon the particular application. Theoretically, the NO_X and ammonia react in the presence of SCR catalysts according to the following equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 6NO_2 \rightarrow 7N_2 + 12H_2O$$
$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O$$

However, side reactions that produce undesirable byproducts can occur between ammonia and sulfur trioxide (SO_3) in the flue gas. These reactions are:

$$2NH_3 + SO_3 + H_2O \rightarrow (NH_4)_2SO_4 \quad \text{Ammonium Sulfate (AS)}$$
$$NH_3 + SO_3 + H_2O \rightarrow NH_4HSO_4 \quad \text{Ammonium Bisulfate (ABS)}$$

The SCR operating temperature ranges from 550 to 750°F. As a result, the SCR system normally is located in a high-dust configuration between the boiler economizer flue gas outlet and the air preheater flue gas inlet where the above temperature range normally occurs. Prior to entering the reactor, ammonia is injected into the flue gas at a sufficient distance upstream of the reactor to provide for adequate mixing of the ammonia and flue gas. The quantity of ammonia injected is adjusted to maintain the desired NO_X reduction level (within design limits). NO_X emissions are reduced in direct proportion to the quantity of ammonia injected up to an ammonia-to-NO_X ratio (NH_3/NO_X) of approximately 0.80. Above this value, and as the activity of the catalyst declines with age, some of the ammonia can escape the SCR reactor as ammonia slip. This ammonia can react with small quantities of SO_3 present in the flue gas to form ammonium bisulfate, which can foul and/or increase the corrosion potential for downstream equipment.

C.1.2 Selective Noncatalytic Reduction (SNCR)

SNCR employs chemical injection of ammonia or urea directly into the boiler at a flue gas temperature between 1,600 and 2,100°F. In this temperature range, which is typically near the top of the boiler close to the furnace exit or in the convective pass, the reagent reacts with NO_X to form nitrogen and water without the use of a catalyst to promote the reaction.

As with SCR, the ammonia slip constraint imposes a limit on the maximum amount of NO_X that can be removed with the SNCR process. Because the process is so temperature sensitive, the ability to follow boiler load becomes critical when constrained by ammonia slip limits. Advanced SNCR systems use retractable injection lances that improve load-following control for the process. These lances use a "jet curtain" to provide better cross-sectional coverage and rotation of the lance allows for better response to process signals such as boiler load or furnace temperature.

Application of SNCR to utility-scale boilers is highly site specific. Generally, SNCR is capable of 15 to 40 percent NO_X removal, consistent with a 5-ppm ammonia slip constraint. Removal levels above 40 to 50 percent are difficult to achieve due to the high-ammonia slip that is produced, the stringent requirements placed on the distributions for injected reagents, and the narrow temperature window required for the reaction.

One particular benefit of SNCR as compared to SCR is that capital cost is limited due to the absence of catalyst and the associated reactor vessel. However, potentially much higher ammonia slip levels cause increased downstream problems. In addition, the difficulty in meeting temperature and distribution requirements makes implementation of the technology difficult on many boilers, especially on a large scale boiler (typically greater than 300 MW). SNCR systems also generally require more reducing agent for a given NO_X reduction than do SCR systems since part of the reducing agent can be oxidized at the higher injection temperature, representing an initial loss of reagent. Furthermore, the oxidation product is often NO_X, requiring additional reagent to remove the NO_X formed via oxidation.

C.1.3 HERT SNCR Technology

HERT (High Energy Reagent Technology) is a novel type of SNCR system, owned by ACT (Advanced Combustion Technology). The HERT technology still incorporates the injection of urea into the appropriate temperature window in the furnace in order to achieve the desired reaction between NO_X and ammonia to produce nitrogen and water. However, certain aspects of the HERT system may allow for the use of fewer injectors and less chemical while achieving greater NO_X reductions at the same ammonia slip (<5ppm). HERT uses high velocity carrier air and specially-designed nozzles to allow the urea to penetrate further into the boiler. The carrier air flows around the urea, protecting it upon its initial entrance into the furnace and allowing it to travel further inside, and a mechanical atomizer controls the depth and droplet sizes of the urea spray. Smaller droplets are desired for instant vaporization and immediate reaction with NO_X. Larger droplet sizes are desired where delay of the vaporization of urea is necessary to hit the targeted temperature window. With better penetration, better removals are achieved, and with fewer injectors and less chemical required, capital and O&M costs are potentially lower for this system than for conventional SNCR systems.

HERT systems can be installed as high- or low-momentum systems, or as a combination of both. The high-momentum system involves injection of urea into existing Overfire Air (OFA) ports, and can achieve up to 55 percent NO_X reduction, while the low-momentum system uses a small blower to provide carrier air for urea injection into the upper furnace. Commercial demonstrations of the low-momentum system have shown approximately 30 percent or greater NO_X reductions.

C.1.4 Cofiring Natural Gas

Cofiring natural gas involves the simultaneous firing of natural gas and pulverized coal in a boiler's primary combustion zone. The cofiring rate, or percentage of heat input from natural gas, is typically 10 to 20 percent, but it may be more or less depending on boiler design requirements, gas prices, and availability of natural gas. The advantage of cofiring natural gas with coal is to reduce NO_X emissions with low-capital cost. NO_X reductions come as a result of the lower nitrogen content of natural gas. The disadvantage of cofiring natural gas includes increased flue gas moisture content that results from combustion of the higher hydrogen content of natural gas.

C.1.5 Upper Furnace Gas Injection (UFGI)

UFGI involves the injection of a small percentage (3 to 7 percent) of natural gas (on a Btu input basis) into the upper furnace of a boiler. To reduce NO_X emissions the gas is combusted in a low-oxygen environment at temperatures ranging from 2,000 to 2,400°F. Simply put, methane in the natural gas reacts with NO_X to form hydrogen, carbon, and nitrogen (HCN) and oxygen. The HCN product further reacts with other NO_X to form nitrogen, water, and carbon dioxide. This process is typically carried out without the use of "burn-out" air above the gas injection zone. The limiting parameter of the performance of UFGI is primarily carbon monoxide (CO) emissions resulting from overall fuel-lean furnace conditions.

Amine-Enhanced Fuel Lean Gas Reburn (AEFLGR™) Process

The AEFLGR™ Process is a combination of the Fuel Lean Gas Reburn (FLGR™), developed by Energy Systems Associates and the Gas Research Institute, with the NO_XOUT™ SNCR Process, commercialized by Fuel Tech, Inc. In AEFLGR™, natural gas is introduced into the boiler above the primary combustion zone using high velocity gas jets. NO_XOUT™ reagent (urea-based) is injected as a liquid within the gas jets. The flow rate of gas is controlled in order to maintain an overall fuel-lean stoichiometry in the upper furnace. Selective chemical reactions between the nitrogen oxides and the decomposition products of the gas and urea reduce the level of NO_X emissions.

The NO_XOUT^{TM} SNCR Process operates most effectively when the flue gas temperatures are between 1,700 to 2,000°F. Above this temperature range a portion of the amine species oxidizes to NO. Below these temperatures, the reaction rates are much slower and intermediate species (such as ammonia compounds) do not have time to fully react. Addition of natural gas in the AEFLGR™ Process widens this temperature range, so NO_X reduction can be achieved from 1,700 to 2,300°F.

Reduction of NO_X using gas reburning is most effective when oxygen levels are low. However, under conditions of very low oxygen, the hydrocarbon species do not completely combust, resulting in high levels of CO and LOI (i.e. unburned carbon in ash). High CO levels can interfere with SNCR reactions, and can exceed emissions limits. Consequently, there is a practical limit to the operating levels of O_2 – too low results in operations and emissions problems; too high results in less than optimal NO_X reduction.

FLGR™ and AEFLGR™ differ from traditional gas reburning in that the amount of reburning fuel introduced is less than the amount required to consume all the excess air. The flue gas remains "fuel lean" in the reburn zone, and no additional air is required to complete combustion. Traditional reburning processes usually require combustion modifications and air supply modifications to create a burnout zone above the gas injection. Typically, in the FLGR™ and AEFLGR™ processes the reburn fuel accounts for up to 8 percent of the gross heat input of the unit, compared with 10 to 20 percent for traditional reburning and advanced reburning.

The AEFLGR™ process uses high velocity turbulent jets for dispersing gas into the furnace. As the jets mix with the flue gas, the combustion process consumes the excess oxygen. Often, the fuel and air are not evenly distributed in the boiler and regions of flue gas will have different compositions, including zones of high CO or high O_2. Adjustment of individual nozzles is often necessary to optimize performance.

Capital expenditures for AEFLGR™ average $7-30/kW, depending on the size of the boiler. NO_X reductions from this technology have approached 60 percent: however, actual sustained performance is dependent on boiler size. Substantial NO_X reductions are challenging on large boilers due to load following constraints, reagent mixing, and temperature distribution. As with other furnace injection ammonia technologies, maintaining ammonia slip at tolerable limits is also a challenge for AEFLGR™. Ammonia slip excursions (>5-10ppm) result in balance of plant impacts such as air preheater pluggage and contaminated fly ash rendering it unsellable. As in the discussion of gas reburn technology, AEFLGR™ alone cannot achieve adequate NO_X reductions to meet regulatory requirements; therefore, this technology was not considered a viable option for this large boiler application.

C.1.6 Low-NO_X Burners (LNBs)

Low-NO_X burner is a generic term for a burner designed to combust the fuel while reducing the amount of NO_X that is formed. Since there are several different firing arrangements for oil- and coal-fired boilers there are several different types of LNBs.

NO_X is formed during combustion from either the nitrogen in the fuel or the air. NO_X formed from nitrogen in air requires high-flame temperatures and because of this, is usually referred to as thermal NO_X. Some fuels, particularly coal and oil, contain small amounts (2 percent or less) of nitrogen as a chemical constituent. When these fuels are burned, this fuel nitrogen can be oxidized in the flame-producing NO_X, which is referred to as fuel NO_X. Thus coal and oil can form NO_X from the thermal NO_X and the fuel NO_X mechanisms, but the fuel-nitrogen pathway is by far the predominant one. Since natural gas contains no fuel nitrogen, thermal NO_X only is formed, explaining why natural gas flames have much lower NO_X levels than coal.

LNBs for coal and heavy oil are designed to reduce NO_X by allowing the fuel nitrogen to be released from the fuel in a region with low-oxygen concentration. Most of the fuel nitrogen can then react to molecular nitrogen (N_2, which is present in the air). High temperatures are needed to extract most of the nitrogen from the fuel and low-oxygen concentrations are also necessary to prevent the fuel nitrogen from being oxidized. This approach is known as air staging because a portion of the combustion air must be introduced later in the combustion process to form this low-oxygen reduction zone. Wall-fired LNBs achieve this end by creating unique aerodynamic in each burner's flame while, in a tangentially fired furnace, a portion of the secondary air is diverted above the flame (overfire air), producing a low-oxygen zone in the entire lower furnace.

LNBs for wall-fired units are typically dual-register burners. By using two separate registers for the secondary air, some of the secondary air is used to initiate and stabilize the flame (with inner-register air), while most of the secondary air is directed by the outer register to bypass the initial flame and then mix with the flame after the fuel nitrogen is released and converted to N_2. Different manufacturers use different hardware implementations for this process, but the general technical concept is pretty much the same. Most also use some means of ensuring the flame stays attached to the tip of the burner. A stable, attached flame is a lower NO_X producer than either an unstable flame or a detached flame.

LNBs for tangentially fired boilers serve to assist in NO_X reduction by supporting the air staging used for the major NO_X reduction technique. The details of these different approaches are described below in items C.1.7, C.1.8, and C.1.9.

C.1.7 Overfire Air (OFA)

The most general approach to lowering NO_X produced in oil or coal combustion is to create a main flame zone that is deficient in oxygen and is known as a reducing atmosphere. If the temperature can be held high in this reducing zone the majority of the fuel nitrogen can be driven from the fuel. Since little oxygen would be present, this fuel nitrogen then reacts to form molecular nitrogen (N_2), which is the main constituent of air. OFA is the air that is added to finish the combustion process started in the combustion zone. In a vertical flow typical of boilers, the reducing zone is the main combustion zone, OFA is added above this flame zone, thus the name "overfire" air.

Up to approximately 30 percent of the total air needed for combustion may be supplied as OFA. As the amount of OFA increases, the NO_X emissions of the combustion process decrease, up to a point. Any further increase in the amount of OFA above this point will cause the NO_X emissions to increase. The practical limitations on the amount of OFA that can be used are:

- Stability of the main flame
- Corrosion of the metal steam tubes
- Production of carbon monoxide
- Increases in the amount of unburned carbon that escapes the furnace and is collected with the fly ash

OFA is a part of most of the tangentially fired NO_X control systems. Generally, in these systems, the two types of OFA are:

- Separated overfire air (SOFA)
- Close-coupled overfire air (CCOFA)

As the names suggest, any OFA close to the main combustion zone is classified as close-coupled. When OFA is injected some distance above the main combustion zone, it is classified as SOFA. As the distance from the flame zone increases, the effectiveness of the OFA for NO_X control increases; however, the installation costs also increase.

OFA can be used in wall-fired configurations but has not been widely used due to the creation of excessive amounts of unburned carbon in fly ash.

C.1.8 Low-NO_X Concentric Firing System (LNCFS)

The LNCFS is an invention of Asea Brown Boveri Combustion Engineering (ABBCE) intended to reduce NO_X emissions from a tangentially fired boiler. The LNCFS family of systems, including Levels I, II, and III, was developed to provide a stepwise reduction in NO_X emissions, with LNCFS Level III providing the greatest reduction. System descriptions are:

A. Level I — In LNCFS Level I, a CCOFA system is integrated directly into the windbox. Compared to the baseline configuration, LNCFS, LNCFS Level I is arranged by exchanging the highest coal nozzle with the air nozzle immediately below it. This configuration provides the NO_X reduction advantages of an OFA system without pressure part changes to the boiler.

B. Level II — In LNCFS Level II, a SOFA system is used. This is an advanced OFA system having backpressuring and flow-measurement capabilities. The air supply ductwork for the SOFA is taken from the secondary-air duct and routed to the corners of the furnace above the existing windbox. The inlet pressure to the SOFA system can be increased above windbox pressure using dampers downstream of the takeoff in the secondary-air duct. The intent of operating at a higher pressure is to increase the quantity and injection velocity of the OFA into the furnace. A multicell venturi is used to measures the amount of air flow through the SOFA system.

C. Level III — LNCFS Level III uses both CCOFA and SOFA.

In addition to OFA, LNCFS incorporates other NO_X-reducing techniques into the combustion process. Using offset air, two concentric circular combustion regions are formed. The inner region contains the majority of the coal, thereby being fuel rich. This region is surrounded by a fuel-lean zone containing combustion air. For this purpose, the size of this outer circle of combustion air will be varied using adjustable offset air nozzles. The separation of air and coal at the burner level further reduces the production of NO_X.

C.1.9 Deep-Staging Low-NO_X Burners (ABB TFS 2000R)

Asea Brown Boveri Combustion Engineering's (ABBCE) TFS 2000R system was a major evolution of the ABBCE LNCFS family of low-NO_X products. The four major components of this system are:

- Precise furnace stoichiometry history control
- Initial combustion process control
- Concentric firing
- Dynamic classifiers installed on the pulverizers

The control of furnace stoichiometry uses multiple levels of OFA to stage the combustion process and pushes the stoichiometry of the flame zone to more severe reducing conditions than any of the other LNCFS systems. Thus, the TFS 2000R system achieves deeper staging of the combustion air.

The initial combustion process control is achieved by the use of coal nozzle tips to control the flame front. If the flame front is held on the nozzle tip, mixing of air and coal is delayed and helps the devolatilization of the coal to proceed under low-oxygen conditions. The concentric firing system is utilized in all of ABBCE's low-NO_X products described above. Finally, dynamic classifiers are added to the coal pulverizers to reduce the initial coal-particle size that is fed to the combustion process, which should help reduce the amount of unburned carbon that escapes the radiant furnace.

The TFS 2000 system is available for new plant construction and has been used at a facility located near Richmond, Virginia. The "R" designation at the end of the TFS 2000 trademark is to identify it as a retrofit option for existing power plants. Given an existing plant, design compromises due to furnace size, access, location of air ducting, etc., mean that a retrofit installation will rarely meet the projections for a new plant TFS 2000 system and normally will have a less impressive NO_X performance.

C.1.10 Low-NO_X Burner Tips (ABB P2)

ABBCE's P2 system is a standard offering for smaller tangentially fired boilers. This arrangement, offered as a retrofit to the conventional, higher NO_X original burner system, consists of new coal burner tips, the concentric firing system (CFS) nozzle tips, and conversion of the top-air compartments to vaned close-coupled overfire air (VCCOFA) nozzles. These burner tips cause the flame to stay attached to the nozzle and limit the mixing of the air and burning coal near the nozzle exit. The CFS is identical to that described above for the LNCFS levels. These first two changes do help lower NO_X, but most of the NO_X reduction is achieved through the installation of the VCCOFA nozzles. In the burner retrofit, the top-air nozzle is removed and replaced with the VCCOFA nozzles. These nozzles point the air upward at a fixed angle and have low drag to air flow, which serves to increase the amount of air going through the nozzles. The VCCOFA is an invention that ads OFA capability without windbox, duct, or pressure-part changes.

Overall, the P2 firing system is a relatively modest low-NO_X firing system that also has a moderate NO_X performance. In the first installation at Duke Energy's Cliffside Unit 3, NO_X was reduced approximately 47 percent with an increase in LOI from 10.3 to 13.4 percent.

C.1.11 Generic NO_X Control Intelligent System (GNOCIS)

GNOCIS is an on-line enhancement to digital control systems and plant information systems targeted at improving unit performance parameters such as heat rate, boiler efficiency, NO_X emissions, and fly-ash-carbon levels. The GNOCIS methodology utilizes a neural network model of the boiler combustion process and when applicable, other plant processes. The software applies an optimizing procedure to identify the best set points for the plant, which are implemented automatically without operator intervention (closed loop), or, at the plant's discretion, conveyed to the plant operators for implementation (open loop). GNOCIS development was funded by the Electric Power Research Institute, PowerGen, Radian International, Southern Company, UK Department of Trade and Industry, and the U.S. Department of Energy.

As of January 1999, over 50 active or planned GNOCIS installations represent greater than 25,000 MW of generation. The installations include both Southern Company and external sites, and both wall- and corner-fired units. The NO_X reduction potential of GNOCIS is dependent upon many factors, including boiler type, fuel characteristics, goal definition, and the range permitted for recommended setpoints; however, to date, reductions of 10 to 20 percent have been observed on the majority of installations. In many of these, boiler efficiency/heat rate improvements have also been observed. Given the relative-low cost of the technology, GNOCIS is a cost-effective NO_X control option for many plants.

C.1.12 Rotating Overfire Air (ROFA) and Rotamix

ROFA is a second generation OFA system. Combustion is enhanced by creating upper boiler turbulence with high velocity air injection through asymmetrically located injection boxes in the boiler walls. Typically, this high velocity air is provided by additional booster fans and is introduced through injection boxes tangentially in the upper furnace region to disturb the otherwise stratified flow. This increased turbulence also increases retention time allowing more complete burnout of the flue gas constituents like NO_X, unburned carbon, and CO. Each ROFA installation is unit-specific to optimize efficiency.

Rotamix is a second generation SNCR system designed to work along with the basic ROFA system or without ROFA through injectors located in the upper furnace. One difference between the Rotamix technology and conventional SNCR systems is the introduction of the urea reagent with high velocity carrier air through the use of large fans. The amount of reagent added into the furnace is governed by the furnace temperature, fuel flow and steam production.

C.1.13 Powder River Basin (PRB) Coal

PRB coal is a subbituminous coal mined primarily from seams in the PRB located in the western United States. Reasons for broadening the use of PRB coal include favorable economics and the added benefits of lower fuel-bound nitrogen and sulfur components that enhance the ability of generating units to minimize NO_X, as well as SO_2 emissions. Additional NO_X reductions are realized because of the lower combustion flame temperature brought about by the higher moisture content in PRB coal. But, with this increase in moisture content come lower heat contents (heating values), suppression of mill outlet temperatures below design minimums, possible loss of generation due to unit-load deratings, and potential increased forced outage rates during the peak season. Increased heat rate and higher operating and maintenance costs are also usually associated with a switch to PRB coal from bituminous coal. Compacting the stockout piles and increased housekeeping around transfer points are considerations to alleviate potential problems with self-heating of the higher-reactivity PRB coal. Soot blower maintenance and increased boiler inspection may be required to maintain/sustain boiler operation. ESP capacity may also be affected and additional fields or flue gas conditioning may be required to adequately collect the PRB fly ash. The impact on SCR catalyst activity of elevated levels of alkali earth metals in PRB fly ash is also a concern.

C.2 SO_2 EMISSION CONTROL ALTERNATIVES

C.2.1 Flue Gas Desulfurization (FGD)

Flue gas from coal- and oil-fired boilers will contain sulfur oxides produced from any sulfur in the fuel. FGD is any process that removes these sulfur oxides, primarily sulfur dioxide (SO_2) with a small amount of sulfur trioxide (SO_3). These sulfur oxides, or SO_X, can range from 0.3 percent of the flue gas by volume down to several hundred parts per million. The two main types of processes are characterized by either wet- or dry-process chemistry.

As implied by the category, wet processes collect the SO_X by treating the flue gas with a water-based solution or slurry. Typically, the utility industry uses a spray tower module where the flue gas flows up through a series of nozzles that spray the alkaline solution into the flue gas. The common chemical used in wet scrubbers is limestone ($CaCO_3$) and the solids produced by modern designs are predominantly calcium sulfate ($CaSO_4$), or gypsum. This gypsum can either be sold as a pre-cursor to wallboard or be disposed of in a landfill or pond. The wet processes are very efficient and remove 80 to 99 percent of the SO_X in flue gas with 95 percent removal typical.

Dry processes inject an alkaline slurry into the flue gas stream in a spray dryer followed by a particulate control device. The spray dryer is a unit where the hot flue gases are contacted with the wet alkaline spray that absorbs the SO_2. The hot flue gas evaporates the water and leaves a dry residue that can then be captured with the fly ash, typically in a baghouse. ESPs are normally not used behind a spray dryer because of the high resistivity of the calcium residues that are added to the fly ash. The residue also contains a mixture of calcium sulfite/sulfate, along with the fly ash from the fuel. This waste is not suitable for other uses and must be disposed of in a landfill or pond. Dry scrubbing can remove 75 to 90 percent of the SO_2 in flue gas.

C.3 PARTICULATE AND MERCURY EMISSION CONTROL ALTERNATIVES

C.3.1 Compact Hybrid Particulate Collector (COHPAC)

COHPAC is a novel, low-cost, retrofit particulate concept developed by EPRI to improve the performance of ESPs. The basic concept is to place a pulse-jet fabric filter (PJFF) downstream of an existing ESP to serve as a "polishing" or performance-upgrading unit. The flue gas enters the PJFF and passes through the fabric where the fly ash particles are filtered from the gas. The particles are collected on the outside of the fabric and the resulting dust layer is cleaned by air pulses (that is, the nomenclature pulse-jet fabric filters). Since the ESP removes a significant amount of the particles from the gas stream the flue gas reaching the baghouse has a significantly reduced dust load. The residual electrical charge from particle charging in the ESP and low-dust loading enables the COHPAC PJFF to operate at an air-to-cloth ratio (A/C) in the 8 to 12 range. (A/C is a ratio of the amount of gas to the amount of fabric present.) A typical full-scale PJFF must operate at A/C ratios of 4 or below, allowing the physical size of a COHPAC PJFF to be up to one-fourth the size of a normal PJFF, which reduces the cost significantly.

Currently, COPHAC can be deployed in two distinct configurations:

- COHPAC I, which a stand-alone casing to house the PJFF
- COHPAC II, which uses the last field of the precipitator to house the PJFF

C.3.2 Activated Carbon Injection

Activated carbon injection (ACI) for mercury control involves the addition of powdered activated carbon to flue gas streams where it adsorbs vapor phase mercury. This powdered material is made by "cooking" low rank coals with steam and temperature to activate the surface, generating a highly reactive product that acts like a chemical sponge. Once injected into the flue gas, the activated carbon (and adsorbed mercury) must be collected in a particulate collection device. To date, the most common applications of this technology have either been (1) ahead of an electrostatic precipitator (ESP) or (2) downstream of an existing ESP but upstream of a high ratio (COHPAC) baghouse.

The first configuration mentioned above has been tested under various conditions with wide ranging results depending on contact time, fuel type, ESP size, and process conditions. Typically, due to rapid removal of the carbon in the ESP and limited contact time with the flue gas, these applications are limited to ~50-percent control of vapor phase mercury. A significant concern in this application is the co-mingling of activated carbon and fly-ash, which typically renders the fly-ash unsuitable for secondary use in building materials and forces the operator to dispose of this stream.

The second application, injection into a COHPAC baghouse, is an EPRI patented technology known as TOXECON™. This process attempts to limit the co-mingling of fly ash and activated carbon by collecting a high fraction of fly ash in the ESP before injecting the activated carbon. Furthermore, because the activated carbon is collected on bag surfaces (where it can stay up to several minutes), the TOXECON™ process can typically achieve much higher removal rates than ESP injection (approaching 80 percent), again depending on fuel type and process conditions. The primary drawback to this process is the added financial requirement in building a COHPAC baghouse, which will significantly affect the overall cost of mercury removal.

C.3.3 Chemical Injection for Mercury Removal

One relatively quick and inexpensive way to capture and remove mercury from a flue gas stream is through the injection of chemical additives. PRB coal contains a large percent of elemental mercury, which is insoluble in a wet flue gas desulfurization (scrubber) systems. The presence of relatively high levels of elemental mercury and very little oxidized mercury in PRB coals is due to low levels of chlorine in the PRB coal, relative to other coals. High chlorine concentrations in many coals contribute to higher levels of oxidized mercury upon combustion. Certain halogens, including chlorine and bromine, can be injected to oxidize the elemental mercury in PRB, and other low chlorine coals, so that the oxidized mercury can be captured in a flue gas desulfurization scrubber. This technology is currently being tested and if halogen injection proves to oxidize a high percentage of the elemental mercury, a costly baghouse, which can be used to capture elemental mercury, may not be needed.

C.3.4 High Temperature Sorbent Injection

High Temperature Sorbent Injection could provide an enhanced alternative to conventional activated carbon injection technology by yielding even higher mercury removals and by preserving flyash quality. The technology, developed by MinPlus and REI, involves the injection of a non-carbon sorbent in the upper furnace. Tests on a 67-MW unit resulted in a mercury capture of 95 percent over baseline. The thermally produced mineral sorbent consists of metacaolinite, calcium carbonate, calcium oxide and calcium hydroxide.

High Temperature Sorbent Injection provides consistent results by chemically binding to elemental mercury in the boiler before its partial oxidation, whereas during activated carbon injection, the sorbent physically binds to the mercury downstream of the air heater where multiple factors can affect mercury controls. The flyash quality is not altered with this technology since the mercury is chemically bound to the sorbent and will not leach unless temperatures exceed 1632°F. The flyash can therefore be sold for cement and concrete applications. Hot-side sorbent injection also causes no residual disposal problem. Hot-side sorbent injection has been repeatedly successful in packed-bed studies and in semi-industrial and full-scale power plant tests. If realized as a permanent mercury control, the technology would require relatively low capital and operation costs as compared to other control methods.

APPENDIX D

State of Florida and State of Mississippi CAIR Rules

Department of Environmental Protection

Jeb Bush
Governor

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Colleen Castille
Secretary

To: Chairman and Members
Environmental Regulation Commission

From: Mike Sole, Deputy Secretary
Regulatory Programs and Energy

Date: June 21, 2006

Subject: June 29, 2006, Rule Adoption Hearing
Rulemaking to Implement the Federal Clean Air Interstate Rule
Amendments to Chapters 62-204, 62-210, and 62-296, F.A.C.

Purpose

The purpose of this rulemaking is to implement the requirements of the federal Clean Air Interstate Rule as it applies to air pollutant emitting sources in Florida.

The federal Clean Air Act gives the United States Environmental Protection Agency (EPA) authority to require submission of an appropriate State Implementation Plan (SIP) revision from any state that contributes to a violation of the National Ambient Air Quality Standards (NAAQS) in any other state. Using this authority, the EPA promulgated the Clean Air Interstate Rule (CAIR) on May 12, 2005. The purpose of CAIR is to reduce emissions of "precursor" pollutants in upwind states that contribute to violations of the NAAQS for fine particles (PM2.5) and ground-level ozone in downwind states in the eastern United States. Twenty-eight states and the District of Columbia are required to comply with CAIR. Each such state must submit a SIP revision to EPA by September 11, 2006, demonstrating that it has adopted all necessary rules to implement the emissions reduction requirements of CAIR.

Florida meets all NAAQS - one of only three states east of the Mississippi River to do so. However, air quality modeling performed by EPA shows that Florida's emissions of two PM2.5 precursor pollutants, sulfur dioxide (SO_2) and nitrogen oxides (NOx), contribute to violations of the PM2.5 air quality standard in Birmingham, Alabama, and Macon and Atlanta, Georgia. The modeling also shows that Florida's ozone-season (May through September) emissions of NOx contribute to violations of the ozone air quality standard in Atlanta. In all cases, the contributions are small, but still greater than EPA-defined "significance" levels. As a result, Florida is one of the 28 states that must adopt rules to implement CAIR, both for PM2.5 and ground-level ozone.

The proposed amendments to Chapters 62-204, 62-210, and 62-296, Florida Administrative Code (F.A.C), are intended to satisfy the requirements of CAIR. If approved by the Environmental Regulation Commission (ERC), the Department of Environmental Protection (department) will submit the rules to EPA for approval as Florida's required SIP revision for CAIR. In addition to satisfying the public hearing requirements of section 120.54, Florida Statutes, the June 29, 2006 ERC rule adoption hearing is intended to satisfy the public hearing requirements of 40 CFR 51.102 for proposed SIP revisions.

<u>Summary</u>

CAIR Compliance Options

In developing CAIR, EPA determined that large reductions in SO_2 and NOx emissions could be obtained from electric generating units (EGUs) in a highly cost-effective manner. For each state that was determined to contribute to a PM2.5 or ozone nonattainment area in a downwind state, EPA established emissions budgets or "caps" on precursor emissions in the state based on the application of cost-effective emissions controls on EGUs. Finally, EPA provided that the caps be implemented in two phases.

States that contribute to a PM2.5 violation in a downwind state must comply with caps on *annual* EGU emissions of both SO_2 and NOx. The Phase 1 caps take effect in 2009 for NOx and 2010 for SO_2. Beginning in 2015, both caps are reduced and become permanent. States that contribute to an ozone violation in a downwind state must comply with a cap on *ozone-season* EGU emissions of NOx, where "ozone season" is defined as May through September. The Phase 1 ozone-season cap takes effect in 2009 and steps down in 2015, becoming permanent thereafter. The ozone-season cap on NOx emissions is separate from the annual NOx cap; Florida must comply with both independently.

While the CAIR emissions caps are based on the application of cost-effective controls on EGUs, a state may elect to control other source categories, either in addition to or in lieu of EGUs, to comply with its emissions caps. If a state chooses to control EGUs only, EPA gives the state the option of participating in "cap-and-trade" programs administered by EPA for each of the three possible caps: annual SO_2, annual NOx, and ozone-season NOx. The department believes that cap-and-trade is the best option for complying with all three emissions caps under CAIR. Florida does not have a large base of industrial emission sources from which to obtain alternative emission reductions. More importantly, any strategy involving sources other than EGUs precludes participation by the state in the EPA-administered cap-and-trade programs, thus denying Florida's EGUs access to the national allowance market and the flexibilities it provides. Through this rulemaking, the department is proposing that Florida control EGUs only and do so by opting-in to the EPA-administered cap-and-trade programs.

Mechanics of CAIR Cap-and-Trade Programs

Under the annual and ozone-season NOx cap-and-trade programs, EPA provides annual and ozone-season emissions allowances for NOx to each participating state in an amount equal to the state's caps for each year. The state, in turn, allocates all or part of those allowances to its EGUs. The number of NOx allowances received by any EGU for a given year depends on the allocation system employed by the state. The NOx allowances allocated to EGUs by the state are deposited into compliance accounts established by EPA for each affected unit. Each unit must ensure that at the end of each year and each ozone season, it holds enough eligible annual and ozone-season NOx allowances, respectively, in its compliance accounts to cover its NOx emissions for the year or ozone-season. EPA then deducts, or retires, from each unit's compliance account an amount of allowances equal to the unit's reported NOx emissions. A unit can only use allowances allocated for the control year or any previous year to satisfy its annual and ozone-season compliance requirements; it cannot use any future-year allowances it may hold.

The annual SO_2 cap-and-trade program builds on the existing federal acid rain program created by the Clean Air Act Amendments of 1990. EPA has already allocated emission allowances for SO_2 to sources subject to the acid rain program. These allowances will be used in the CAIR model SO_2 trading program. A participating state has no control over the number of SO_2 allowances received by its EGUs.

Under all three of the CAIR cap-and-trade programs, allowances may be traded with sources in other participating states or "banked" for future use. As a result, EGUs are able to choose from many compliance alternatives, including installing pollution control equipment, switching fuels, or buying excess allowances from other sources that have "over-controlled" their emissions. Because each EGU must hold sufficient allowances to cover its emissions each year, the limited number of allowances available ensures that emission reductions are achieved. The mandatory emission caps, along with stringent emissions monitoring and reporting requirements and significant EPA-imposed automatic penalties for noncompliance, ensure that human health and environmental goals are achieved and sustained.

Details of Opting-in to CAIR Cap-and-Trade Programs

EPA has developed "CAIR model rules" for each of the three CAIR cap-and-trade programs (annual SO_2, annual NOx, and ozone season NOx). If a state chooses to opt-in to any of the EPA-administered cap-and-trade programs, it must adopt by reference or otherwise adhere to the corresponding model rule with only such limited modifications as are allowed by EPA. The only modifications allowed by EPA relate to the methodology for allocating annual and ozone-season NOx allowances to individual EGUs. While the CAIR model rules provide a suggested methodology, EPA allows each participating state to allocate annual and ozone-season NOx allowances to its EGUs in any manner of its choosing as long as the state caps are not exceeded and certain other conditions are met. The department has taken advantage of this flexibility to develop an allocation methodology that is similar to the model rule approach but includes certain changes to address Florida-specific issues and to effect a smoother administration of the program.

If the department's proposed allocation methodology is approved by the ERC through this rulemaking, the department will, as soon as possible thereafter, issue an administrative order setting forth the annual and ozone-season NOx allowances determined for each EGU for control years 2009 through 2012 based on the adopted methodology. These allocations must be submitted to EPA by October 31, 2006, for recordation in the EPA compliance accounts of each affected EGU.

It should be noted that if a state fails to timely submit an approvable CAIR SIP revision, it will lose the flexibility to allocate annual and ozone-season NOx allowances as it sees fit. Instead, EPA will impose the model rule methodology on the state by default and allocate allowances to the state's EGUs accordingly. Given this reality, the department used the model rule as its starting point for developing Florida's proposed allocation methodology. Attachment E provides a comparison of the NOx allocation methodology in the EPA model rule to the methodology proposed in this rulemaking.

The following two tables show the EPA-projected emission reductions that Florida is expected to realize by opting-in to the CAIR cap-and trade programs for annual SO2, annual NOx, and ozone season NOx emissions. As can be seen from the tables, participation in the cap-and-trade programs is expected to result in significant emission reductions: 65 percent for SO_2 and 76 percent for NOx by 2015. Similar large emission reductions are also projected for other nearby states.

CAIR Annual Emission Caps and Projected Emission Reductions for Florida

	Current (2003) Power Plant Emissions (tons/year)	CAIR Phase 1 Emission Cap (tons/year)	EPA-Projected Phase 1 Emissions (tons/year)	CAIR Phase 2 Emission Cap (tons/year)	EPA-Projected Phase 2 Emissions (tons/year)
SO_2	475,000	*2010 - 2014* 253,450	218,000 *(54% reduction)*	*2015-on* 177,415	167,000 *(65% reduction)*
NOx	253,000	*2009 - 2014* 99,445	69,000 *(73% reduction)*	*2015-on* 82,871	61,000 *(76% reduction)*

CAIR Ozone Season (May through September) Emission Caps and Projected Emission Reductions for Florida

	Current (2003) Power Plant Emissions (tons/season)	CAIR Phase 1 Emission Cap (tons/season)	EPA-Projected Phase 1 Emissions (tons/season)	CAIR Phase 2 Emission Cap (tons/season)	EPA-Projected Phase 2 Emissions (tons/season)
NOx	119,000	*2009 - 2014* 47,912	33,000 *(72% reduction)*	*2015-on* 39,926	29,000 *(76% reduction)*

Statutory Authority

Section 403.061(35), Florida Statutes, authorizes the department to "exercise the duties, powers, and responsibilities required of the state under the federal Clean Air Act." These duties and responsibilities include the development and periodic updating of Florida's SIP. The rule amendments to implement CAIR are being proposed pursuant to this specific statutory authority. (Note: the SIP is not a discrete document; rather, it is the body of state rules, rule amendments, orders, and technical materials submitted to, and approved by EPA as SIP revisions over the past 35 years.)

Department's Rule Development Process

The department's Division of Air Resource Management held two conceptual workshops (November 29, 2005, and March 2, 2006) and one rulemaking workshop (April 13, 2006) to present options for implementing CAIR in Florida and to provide opportunities for public comment. Following each workshop, comments received by the division were posted on its website for review by all participants in the rulemaking process and other interested parties. See http://www.dep.state.fl.us/Air/rules/regulatory.htm.

Focus of the Rule Development

The focus of the workshops was on development of a Florida methodology for allocating annual and ozone-season NOx allowances to its EGUs, the only area of flexibility provided to the state under EPA's cap-and-trade model rules. As mentioned previously, under the CAIR SO_2 cap-and-trade program, allowances are allocated through the existing federal acid rain program and cannot be modified by the state. Florida, however, can allocate annual and ozone season NOx allowances as it sees fit, as long as the statewide caps are not exceeded.

Even though the statewide NOx caps are fixed, different allocation methods give rise to different amounts of allowances for individual plants and utilities. Since allowances have monetary value, each utility tends to favor the allocation method that provides it with the greatest number of allowances. During the course of the rule development process, several different methodologies for allocating NOx allowances were put forward by the various stakeholders.

All of the methodologies use either heat input or gross electrical output, or a combination of both, as the metric by which allowances are allocated to individual EGUs. Heat input is essentially a measure of the amount of fuel burned in a unit. Allocations based on heat input are determined by summing the "baseline" total heat input of all EGUs, computing the ratio of each individual unit's baseline heat input to the total, and allocating allowances pro-rata to the units based on these ratios. For example, a unit that accounts for 4 percent of the state's total baseline heat input receives 4 percent of the allowances. Allocations based on gross electrical output are determined in the same way, except that the ratio of a unit's baseline gross electrical output to the state's total electrical output of all units forms the basis of the pro-rata distribution of allowances.

While all Florida utilities support the department's proposal to opt-in to the CAIR cap-and-trade programs for annual and ozone season NOx emissions, the utilities have been unable to reach agreement among themselves on a preferred methodology for allocating NOx allowances to individual EGUs. The major issues are:

- Allocation methodology for existing units – fuel-neutral vs. fuel-adjusted;
- Allocation methodology for new units – input-based vs. output-based; and
- Baseline period for allocations – updating vs. fixed.

Each of these issues is summarized below.

Allocation Methodology for Existing Units

Under the EPA model rules, existing units are allocated NOx allowances in proportion to their "fuel-adjusted heat input" during the baseline period. Fuel adjustment factors of 1.0, 0.6, and 0.4 are applied for coal, oil, and gas, respectively. Gas-fired turbines are more efficient than coal-fired boilers and emit less NOx per unit of heat input than a coal-fired boiler. Therefore, if NOx allowances are allocated on a "fuel-neutral heat input" basis (no fuel adjustment), an existing gas-fired turbine would receive more allowances relative to its actual NOx emissions than an existing coal-fired boiler. By design, the fuel adjustment factors shift some of the state's NOx allowances from existing oil and gas-fired units to existing coal-fired units in order to provide more allowances to units that face a greater burden in reducing emissions.

Utilities with mostly coal-fired plants argue that the additional allowances they would receive as a result of the fuel adjustment factors are needed to mitigate the costs of retrofitting their older ("grandfathered") units with modern air pollution control equipment—costs the gas-fired plants will not incur. On the other hand, utilities with mostly oil-fired and gas-fired plants argue that their customers are already paying for cleaner generation and should not lose the economic benefit of the additional allowances they would receive if no fuel factors were used.

Having considered these opposing points of view, the department is proposing to follow the EPA model rule approach of allocating NOx allowances to existing units on a fuel-adjusted heat input basis. In addition, the department is proposing to apply a separate fuel factor of 1.5 for existing biomass-fired units that, despite use of the "best available control technology," would otherwise receive substantially fewer allowances than needed. This is consistent with recommendations in Florida's Energy Plan related to encouraging the use of renewable energy resources.

At the May 25, 2006, briefing session, Florida Power and Light Company (FPL) indicated that it will ask the ERC to reject the department's proposal and instead *consider a NOx allocation methodology for existing units that is based on a unit's unadjusted baseline heat input.*

While understanding FPL's position, the department stands by its proposal. The state's existing coal-fired units will bear the brunt of the emission reductions needed for Florida to comply with CAIR. The department believes that the fuel factor adjustment is appropriate to help defray the costs of upgrading the older coal-fired power plants to achieve the needed NOx reductions. In taking this position, the department is giving more weight to the costs that utilities must incur to comply with CAIR than to any technology or fuel-related decisions utilities may have made prior to CAIR and independent of its requirements.

Allocation Methodology for New Units

As stated above, with a heat-input-based system, allowances are allocated in proportion to a unit's fuel usage during its baseline period. With an output-based system, allowances are allocated in proportion to a unit's gross electrical output during its baseline period. The output approach is "fuel neutral" and does not adjust allowances based on the type of fuel used to generate the electrical power.

The EPA model rules allocate allowances to new units using a "modified output" approach (also referred to as the "converted input" method). Under this approach, a unit's electrical output is converted to a nominal heat input value using factors that are designed to reward the use of more efficient technologies; for example, it provides more NOx allowances to a new combined-cycle gas unit than to a new simple-cycle gas unit and more allowances to a new integrated gasification combined cycle (IGCC) coal unit than to a new pulverized coal unit. The conversion from output to heat input is necessary to allow new units, once they have established a baseline, to join the existing unit pool and receive their appropriate pro-rata share of allowances.

The argument for an output-based system is that it favors construction of newer, more efficient units over continued operation of older, less-efficient units. However, some utilities argue that an output-based system inappropriately favors new gas units over new coal units because gas units receive more allowances than needed under the fuel-neutral output-based approach.

To promote efficiency in the design and operation of future power plants, notwithstanding the choice of fuel, the department is proposing to follow the EPA model rule approach of allocating allowances to new units using the modified output methodology. However, to eliminate an unnecessary shift of allowances from existing pre-2001 units to existing pre-2007 units, the department is proposing to change the definition of "existing unit" to include units commencing operation prior to 2007, rather than 2001 as proposed by EPA.

The department does not expect to hear objections to this proposal at the rule adoption hearing; however, during the workshop period, some utilities argued for a fuel-adjusted heat input approach for both existing and new units as a counterpoint to other utility proposals for treating both existing and new units in a fuel-neutral manner.

Updating vs. Fixed Baseline Period

With a fixed baseline period, the number of allowances a unit receives in future years will always be proportional to its level of operations over a fixed historical baseline period (e.g., 2000-2004), even if the unit is later operated at a higher or lower rate, or retired. An updating baseline system keeps the distribution of allowances more closely aligned with actual plant operations in future years by resetting the baseline period for all units on a periodic basis.

Some utilities favor an updating system to prevent inequities in the distribution of future allowances from developing between utilities that experience different rates of demand growth in their respective service areas. Other utilities argue that a fixed baseline provides more certainty for future planning and also encourages early retirement of older units since the utility continues to receive allowances for such units indefinitely.

To provide more certainty for planning, the department proposes to follow the EPA model rule approach of using a fixed baseline period. However, to provide a more equitable distribution of future allowances, the department proposes that retired units receive allowances for no more than 10-12 years after they cease operation, after which their allowances would be redistributed to active units.

The department has received pre-hearing comments from Indiantown Cogeneration and Cedar Bay Generating Company recommending that the baseline period be updated on a regular basis (e.g., every five years), rather than fixed permanently, so that allocations more accurately reflect current operations.

The department believes that the greater certainty provided by a fixed baseline period is important in the early years of the program and, therefore, stands by its proposal. A decision to move to an updating baseline approach could be made at a later time, if the need to do so becomes more apparent.

Technical Analysis of the Department's Proposed Allocation Methodology

Attachment F to this memo lists the 2009-2012 NOx allocations that the department expects to make to individual facilities using the allocation methodology proposed in this rulemaking. The following table shows how the annual NOx allocations would be distributed according to different types of units and fuels using the department's proposed methodology.

Unit Type	Fuel	2009-2012 Annual NOx Allocations (tons)	Actual 2004 NOx Emissions (tons)
Boilers	Biomass	1,208	872
	Coal	55,495	143,061
	Gas	591	1,202
	Oil	18,544	51,515
Combined Cycle	Coal	845	402
Combustion Turbines	Gas	12,863	10,460
	Oil	114	47
Simple Cycle Combustion Turbines	Gas	2,446	1,614
	Oil	2,349	3,791
Grand Total		94,455	212,963

The table shows that most of the state's allowances would be allocated to coal-burning power plants. It also shows that the current level of NOx emissions far exceeds the amount of allocations provided by the CAIR program. Most of the large, uncontrolled coal-burning power plants have indicated that they intend to install NOx control equipment in response to CAIR by or near 2009. The department estimates that these NOx emission reductions will be near 100,000 tons per year, which will make up most, but not all, of the necessary reductions.

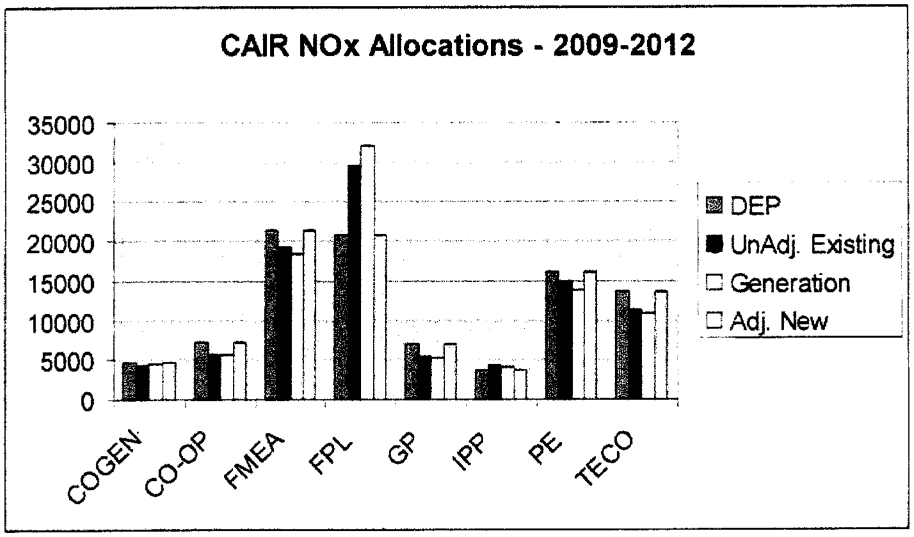
Comparing the Department's Proposal to Other Methodologies

For comparison purposes, the department has calculated CAIR NOx allocations for four alternative allocation methodologies. Of particular interest is the comparison between the department's proposed method and the unadjusted heat input method, since the latter is the approach being advocated by FPL. The generation (output-based) method and adjusted new method reflect other proposals that arose during the workshop process.

1. Department's Proposal: This method allocates NOx allowances based on fuel-adjusted heat input for existing units and converted heat input (based on generation output data) for new units. It is the basic methodology used in the EPA model rule.
2. Unadjusted Heat Input: This method follows the department's proposal, except that there is no fuel adjustment applied to the heat input data for existing sources.
3. Generation (output-based): This method allocates NOx allowances based on gross electrical output for both existing and new units.
4. Adjusted New: This method allocates NOx allowances exactly the same as the department's proposal for existing sources, but uses a fuel-adjusted, alternative

converted heat input method for new sources. Under this method, existing sources retain more allowances and new sources receive fewer allowances than with the other methods, as new sources come into the program.

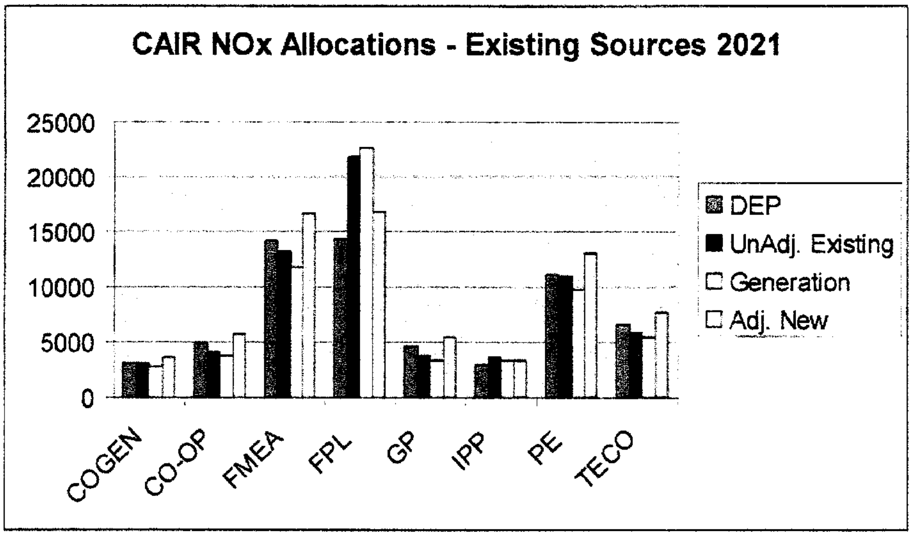
The following three charts show how the annual NOx allocations would be distributed to utility companies and selected utility groups under the four different allocation methods. Units are tons per year.

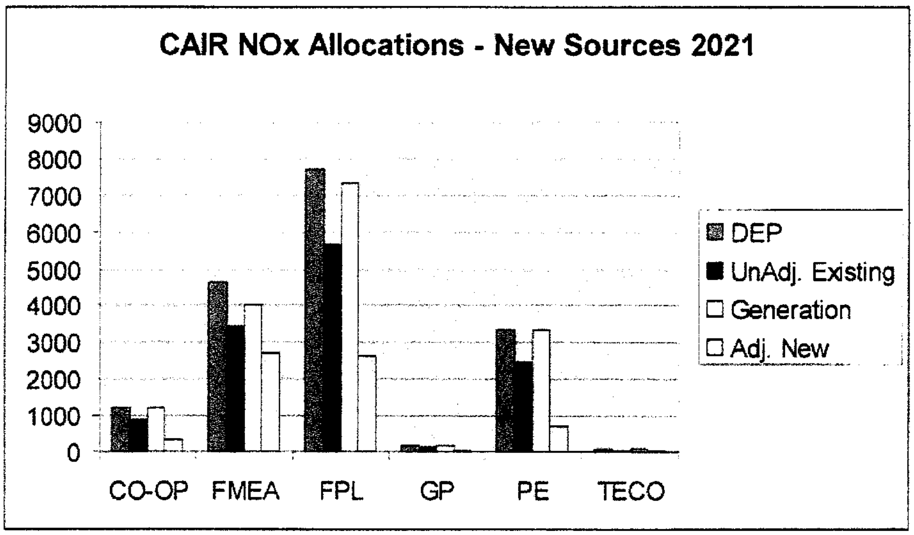


The companies/groups are:
COGEN: Cogeneration units
CO-OP: Co-operative facilities (Seminole Electric)
FMEA: Municipal power generating facilities
FPL: Florida Power and Light
GP: Gulf Power
IPP: Independent power producers
PE: Progress Energy
TECO: Tampa Electric Company

The above chart shows how the respective companies and groups fare according to the different allocation methods for the 2009-2012 allocation. The largest difference in methods occurs for FPL. Both the generation output-based method and the unadjusted heat input method (no fuel factors) provide FPL with significantly more allowances than the department's proposal. Most of the other companies and groups, particularly FMEA and TECO, would correspondingly receive fewer allowances under these two methods.

A look at estimated future allocations, using information on proposed new power plants obtained from the Public Service Commission and the utilities themselves, is provided in the following charts for control year 2021.





Variation among methods in future years for existing sources is similar to 2009-2012, with the exception that the adjusted new method provides more allowances to existing units, and fewer to new units, than the department's proposed method. By 2021, a significant number of new units are included in the baseline allocation (i.e., units coming on-line from 2007 through 2012). The department's proposed method always (at least through 2021) provides new units with sufficient allocations to cover their expected NOx emissions.

Economic Analysis

The department secured the services of Dr. Paul M. Sotkiewcz, Director of Energy Studies with the Public Utilities Research Center (PURC) at the University of Florida, to help the department analyze the economic issues associated with this rulemaking project and to assist in the preparation of a Statement of Estimated Regulatory Cost (SERC). His work is the basis of the following analysis.

Defining Compliance Costs for the CAIR NOx Cap-and-Trade Program

Compliance costs for the CAIR NOx cap-and-trade program are defined to be the costs incurred by utilities that they would otherwise not incur in the absence of the program. Compliance costs include:

1. The purchase or sale of NOx allowances;
2. The installation of NOx control equipment at units in existence at the time of announcement of the CAIR NOx program; and
3. Fuel switching and/or repowering of existing units in response to the CAIR NO_x program.

Utilities will make expenditures on pollution control equipment for other purposes that have nothing to do with CAIR. For example, new units coming into service following the announcement of CAIR must still conform to the best available control technology (BACT) standard which requires installation of NOx control equipment. While BACT compliance may help in CAIR NOx compliance, it would be done regardless and, thus, is not included as a CAIR compliance cost. Additionally, the TECO Big Bend units must, by 2009, install selective catalytic reduction (SCR) systems as part of the department/EPA new source review settlement. These retrofits would have taken place in the absence of the CAIR NOx program and thus are not included as compliance costs.

Given the definition of compliance costs, there are different ways to compare the cost impacts on utilities and their customers. The most obvious is the actual compliance cost incurred. This simple metric does not account for utility size as a measured by kilowatt-hour (kWh) sales. Consequently, the costs per kWh can be used to account for utility size and also provide a measure of the utility customer impact of different allocation schemes.

Defining the Concept of Least-Cost for the CAIR NO_x Program

Cap-and-trade emissions programs such as the CAIR NOx program have the desirable property that they can achieve a given level of emissions reductions at the lowest cost *in aggregate, accounting for all sources.* Least-cost does not necessarily imply that the lowest cost is achieved for any one source or group of sources (utility), but lowest overall. The biggest factor affecting which sources bear the costs of compliance is the *gratis* allocation of allowances because, as will be explained below, the method of allowance allocation has no effect on least-cost compliance behavior.

Allocation Methodology Does Not Affect Least-Cost Compliance Decisions

Contrary to what intuition may indicate, least-cost compliance decisions are not affected by the allocation of allowances. And, by extension, the allocation method for allowances does not affect the overall least-cost for the program accounting for all sources.

Suppose the allowance price is $2,500/ton of NOx as it is in our analysis. And further suppose a source is not allocated any allowances. How would it proceed? The source should install any control technology that results in an abatement cost (*$A*/ton) less than $2,500/ton. Not only will the source reduce the number of allowances it needs by the level of NOx reduction, but it will also save the difference between $2,500/ton and *$A*/ton. Any technologies with a cost of greater than $2,500/ton will not be installed as it is simply less expensive to buy allowances than to install the technology.

Let us now assume that the source is allocated allowances well in excess of its emissions. The source should still install any abatement technology that results in an abatement cost (*$A*/ton) less than $2,500/ton. The source can then sell allowances at $2,500/ton that only cost *$A*/ton to free up to sell. As before, any technologies with a cost of greater than $2,500/ton will not be installed as the cost of freeing up allowances is greater than the revenue from selling them.

Since the allowance allocation does not affect compliance decisions, and the number of allowances is fixed, changing the allocation method such that allowances are transferred from one source to another simply increases the compliance cost by the cost of the allowances in one place, and reduces the compliance cost by the very same amount in the other place. For example, suppose we are allocating 100 allowances between two sources. In one allocation scheme, each source gets 50 allowances. Under a second scheme, one source receives 20 allowances and the other 80. Suppose the allowance price is $2,000. This transfer of 30 allowances increases the costs of one source by $60,000 but decreases the costs of the other source by $60,000, resulting in no net change overall. The only change was in the "burden" of compliance cost across sources.

Model Runs Defining the Upper Bound Cost and Least Cost

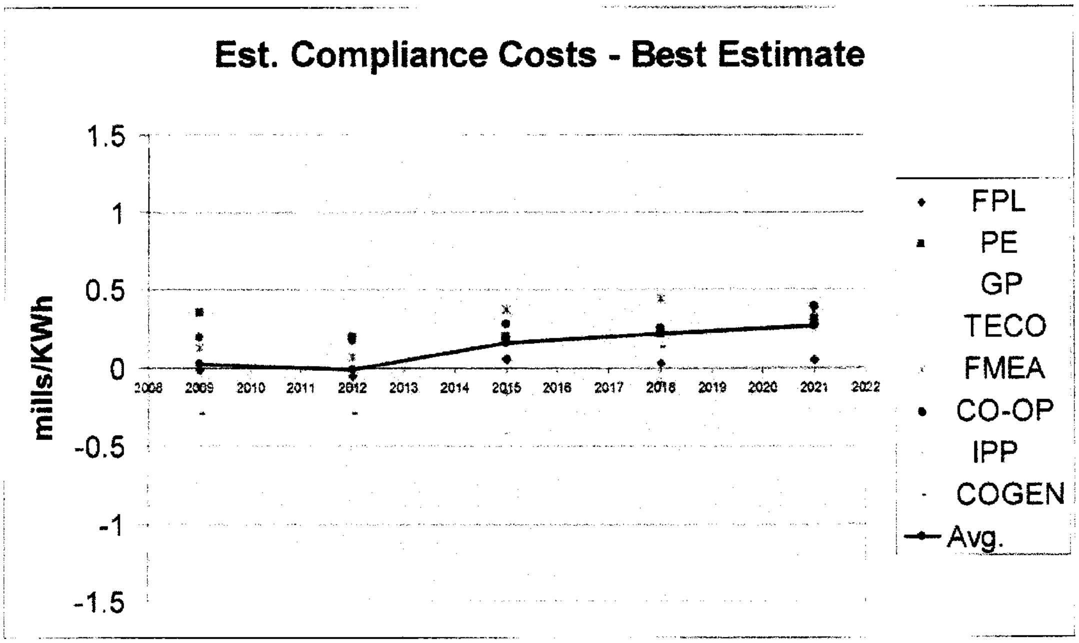
Modeling has been done to determine the upper-bound cost and a least-cost solution for compliance with the CAIR NOx program. In the model runs defining the upper-bound cost for a given allowance price (in this case $2,500/ton), we assume that utilities do not retrofit any of their facilities for NOx control equipment and simply buy allowances from the market to meet their compliance obligations. The reason this model run provides an upper bound is that it is highly likely that utilities will be able to install control equipment that is less costly than buying allowances in the market. The least-cost, or "best estimate," model runs factor in control equipment retrofit decisions that appear economically viable.

The modeling results are summarized below. The first table shows the estimated statewide average compliance cost in mills/kWh for the best estimate and the upper bound. While the specific assumptions used in the best-estimate analysis may be argued, variations of these assumptions in a reasonable manner would still result in compliance costs much closer to the best estimate than to the upper bound. Statewide averages in the near years are actually negative in the best estimate. This means that more allocations are provided than are needed. This is due to new, cleaner and more efficient power coming on-line, replacing some of the older, dirtier units. The cost of these newer units is not considered CAIR-related because the units were planned or built prior to CAIR in response to the growth in demand for generation. Costs increase abruptly in 2015 because the cap is lowered and additional reductions are needed.

Estimated Statewide Average NOx Compliance Costs (mills/kWh)

	Best Estimate	**Upper Bound**
2009	0.024	0.667
2010	-0.006	0.580
2011	-0.013	0.493
2012	-0.010	0.468
2013	-0.021	0.387
2014	-0.024	0.348
2015	0.159	0.530
2016	0.195	0.593
2017	0.190	0.650
2018	0.220	0.662
2019	0.251	0.702
2020	0.239	0.756
2021	0.262	0.786

If a residential customer uses 1,000 kWh/month of electricity and the customer is served by a utility which has a CAIR compliance cost close to the statewide average, the compliance cost to such customer reaches \$0.26/month in 2021 under the best estimate (0.262 mill/kWh x 1000 kWh x .001\$/mill). Compliance costs for individual utilities, or groups, will of course vary around the statewide average. The chart below shows this variation using the department's allocation method for the best estimate.



The least cost is to TECO (in the near years), a consequence of the company having recently reduced emissions significantly at its Gannon/Bayside facility and committed to controls on its Big Bend facility, while being allocated allowances based on operations prior to these changes. TECO would have more allowances than it needs and could sell its excess allowances in the market. The co-generators (COGEN) group, independent power producers (IPP) group, and Florida Power and Light (FPL) would have the next lowest costs. Gulf Power (GP) has the highest estimated costs of compliance.

Below is a cost comparison between the department's proposed allocation method and the unadjusted heat input method favored by FPL. FPL would benefit the most from the unadjusted heat input methodology and Gulf Power would experience the largest disbenefit. While FPL and the IPP group would benefit from the unadjusted heat input method, they are both starting from a relatively low cost of compliance. Some of the companies or groups (GP, CO-OP, FMEA, and PE) have substantially higher CAIR compliance costs than either FPL or the IPP group, which would only become higher under the unadjusted heat input method.

NOx Compliance Cost Comparison
DEP Method vs. Unadjusted Heat Input Method
(Units = mills/kWh)

	2009			2021		
	DEP	**UnAdj.**	**Diff.**	**DEP**	**UnAdj.**	**Diff.**
FPL	-0.01	-0.34	-0.33	0.05	-0.05	-0.10
IPP	-0.12	-0.29	-0.17	0.06	0.02	-0.04
PE	0.35	0.43	0.08	0.31	0.35	0.04
COGEN	-0.29	-0.19	0.10	0.27	0.23	-0.04
FMEA	0.13	0.28	0.15	0.36	0.43	0.07
CO-OP	0.20	0.48	0.28	0.39	0.49	0.10
TECO	-0.97	-0.68	0.29	0.14	0.16	0.02
GP	0.81	1.12	0.31	1.29	1.39	0.10

In summary, the different allocation methods provide for relatively small differences in compliance costs to the different companies or groups (no more than 0.33 mills/kWh), and the statewide average costs of these methods are the same. Further, these differing costs among companies or groups decrease in time and will converge to zero when all existing units are retired.

Proposed Rule Amendments

The department is proposing amendments in three Florida Administrative Code rule chapters to implement the requirements of CAIR:

- Chapter 62-204, Air Pollution Control – General Requirements (OGC No. 06-0327)
- Chapter 62-210, Stationary Sources – General Requirements (OGC No. 06-0193)
- Chapter 62-296, Stationary Sources – Emission Standards (OGC No. 06-0195)

Brief summaries of the proposed amendments are provided below.

Rule 62-204.800, F.A.C., Federal Regulations Adopted by Reference

Rule 62-204.800, F.A.C, is amended to adopt and incorporate by reference the EPA CAIR model rules at 40 CFR Part 96 and related EPA regulations at 40 CFR Parts 72, 73, 77, and 78. As stated in the lead-in text of the rule, the purpose and effect of each federal regulation adopted by reference in this rule section is determined by the context in which it is cited. The new and amended federal regulations adopted by reference in Rule 62-204.800, F.A.C., as part of the CAIR rulemaking project are cited and given context in the department's related proposed amendments to Chapters 62-210 and 62-296, F.A.C. Any substantive modifications to the effects of such federal regulations are also set forth in the proposed amendments to Chapters 62-210 and 62-296, F.A.C.

An underlined, coded copy of the proposed amendments to this rule section can be found at Attachment A.

Rule 62-210.200, F.A.C., Definitions

Rule 62-210.200, F.A.C, is amended to add sixteen new definitions and revise two existing definitions. Some of these definitions are used in Chapter 62-296, F.A.C., in provisions that are not part of the EPA CAIR regulation adopted by reference as part of this rulemaking project. Others are used in proposed CAIR-related amendments to the department's permitting rules for which a notice of proposed rulemaking has not yet been published. The permitting rule amendments will be proposed for Secretarial adoption following adoption of this set of rule amendments.

An underlined, coded copy of the proposed amendments to this rule section can be found at Attachment B.

Rule 62-296.470, F.A.C., Implementation of Federal Clean Air Interstate Rule

New Rule 62-296.470, F.A.C., is the heart of the department's overall rulemaking project related to CAIR implementation. In this rule section, the department sets forth its alternative methodology for distributing NOx allowance allocations to electric generating units. It does so by adopting "substitute language" to be used in applying the EPA CAIR model rules adopted and incorporated by reference at Rule 62-204.800, F.A.C. The substitute language modifies the EPA example allocation method as allowed pursuant to 40 CFR 51.123(o)(2) and (aa)(2).

A state's methodology for allocating NOx allowances to electric generating units is approvable by EPA as long as the state allocates its allowances by certain prescribed dates and imposes no restrictions on their use for trading or banking within the EPA-administered system. EPA does not require the state to allocate a minimum number of allowances to any electric generating unit or to allocate allowances based on fuel usage, electrical output, or any other such system. Therefore, the department's proposed alternative allocation method is not more stringent than any federal standard.

An underlined, coded copy of the proposed amendments to this rule section can be found at Attachment C. A copy of the EPA annual and ozone season NOx allowance allocation rule showing the department's substitute language can be found at Attachment D.

Recommendation

The department recommends approval of the amendments to all three rule chapters as noticed on May 26, 2006.

EXECUTIVE SUMMARY
SIP SUBMITTAL NUMBER 2007-01

IMPLEMENTATION OF CLEAN AIR INTERSTATE RULE

Contents of Executive Summary

Introduction

This proposed revision to Florida's State Implementation Plan (SIP) consists of amendments to Florida Administrative Code (F.A.C.) rule Chapters 62-204, 62-210, and 62-296, F.A.C., The adopted rules enable the Florida Department of Environmental Protection (DEP) to implement the U.S. Environmental Protection Agency's (EPA's) Clean Air Interstate Rule (CAIR); specifically, the cap-and-trade provisions of 40 CFR Part 96, Subparts AA-HH, AAA-HHH, and AAAA-HHHH, as applicable to electric generating units (EGUs) in Florida. This SIP revision is intended to satisfy EPA's April 25, 2005, finding (70 FR 21147) that Florida must revise its SIP to address the contribution of its emissions to fine particle (PM2.5) and ground-level ozone concentrations in downwind states.

Background

The federal Clean Air Act gives EPA the authority to require submission of an appropriate SIP revision from any state that contributes to a violation of the National Ambient Air Quality Standards (NAAQS) in any other state. Using this authority, EPA promulgated the CAIR regulations on May 12, 2005. The purpose of CAIR is to reduce emissions of precursor pollutants in upwind states that contribute to violations of the NAAQS for PM2.5 and ground-level ozone in downwind states in the eastern United States. Twenty-eight (28) states and the District of Columbia are required to comply with

CAIR. Each such state must revise its SIP to implement the emissions reduction requirements of CAIR.

Florida currently meets all NAAQS. However, air quality modeling performed by EPA shows that Florida's emissions of two PM2.5 precursor pollutants, sulfur dioxide (SO_2) and nitrogen oxides (NOx), contribute to violations of the annual PM2.5 air quality standard in Birmingham, Alabama, and Macon & Atlanta, Georgia. The modeling also shows that Florida's ozone-season (May through September) emissions of NOx contribute to violations of the 8-hour ozone air quality standard in Atlanta. In all cases, the contributions are small, but still greater than EPA-defined significance levels. As a result, Florida is required to adopt rules to implement CAIR, both for PM2.5 and ground-level ozone. By adopting such rules and submitting this proposed SIP revision to EPA, Florida is taking action to comply with CAIR and thereby satisfy the EPA finding of April 25, 2005.

Basic CAIR Requirements

In developing CAIR, EPA determined that large reductions in SO_2 and NOx emissions could be obtained from EGUs in a highly cost-effective manner. For each state that was determined to contribute to a PM2.5 or ozone nonattainment area in a downwind state, EPA established emissions caps on precursor emissions in the state based on the application of cost-effective emissions controls on EGUs. Finally, EPA provided that the caps be implemented in two phases.

States that contribute to a PM2.5 violation in a downwind state must comply with caps on *annual* EGU emissions of both SO_2 and NOx. The Phase 1 caps take effect in 2009 for NOx and 2010 for SO_2. Beginning in 2015, both caps are reduced in size and become permanent. States that contribute to an ozone violation in a downwind state must comply with a cap on *ozone-season* EGU emissions of NOx, where "ozone season" is defined as May through September. The Phase 1 ozone-season cap takes effect in 2009 and steps down in 2015, becoming permanent thereafter. The ozone-season cap on NOx emissions is separate from the annual NOx cap; Florida must comply with both independently.

Cap-and-Trade Compliance Option

While the CAIR emissions caps are based on the application of cost-effective controls on EGUs, a state may elect to control other source categories, either in addition to or in lieu of EGUs, to comply with its emissions caps. If a state chooses to require control of EGU emissions only, EPA gives the state the option of participating in a multi-state emissions cap-and-trade program administered by EPA. EPA actually administers three separate cap-and-trade programs, one for each of the three possible emissions caps: annual SO_2, annual NOx, and ozone-season NOx. Through application of the rules comprising this proposed SIP revision, Florida is electing to control EGUs only, and to do so by opting-in to the EPA-administered cap-and-trade programs for all three emissions caps. A state that elects to control only EGUs may nonetheless allow non-EGUs to voluntarily opt-in to its CAIR program under 40 CFR 96, Subparts II and IIII. Florida is electing not to allow non-EGUs opt-ins.

EPA has developed CAIR "model rules" for each of the three CAIR cap-and-trade programs (annual SO_2, annual NOx, and ozone season NOx). By choosing to opt-in to the cap-and-trade programs, Florida must adopt by reference or otherwise adhere to the model rules with only such limited modifications as are allowed by EPA under 40 CFR 51.123(o)(2) and (aa)(2). The principle modifications allowed by EPA relate to the methodology for allocating annual and ozone-season NOx allowances to individual EGUs. While the CAIR model rules provide a suggested methodology, EPA allows a participating state to allocate annual and ozone-season NOx allowances to its EGUs in any manner of its choosing as long as the state caps are not exceeded and certain other conditions are met. Florida has taken advantage of this flexibility to develop an allocation methodology in Rule 62-296.470, F.A.C., which is similar to the model rule but includes certain changes to address Florida-specific issues.

The following two tables show the EPA-projected EGU emission reductions that Florida is expected to realize by opting-in to the CAIR cap-and trade programs for annual SO2, annual NOx, and ozone season NOx emissions. As can be seen from the tables, participation in the cap-and-trade programs is expected to result in significant emission reductions: 65 percent for SO_2 and 76 percent for NOx by 2015. Similar, large EGU emission reductions are also projected for nearby states.

CAIR Annual Emission Caps and Projected Emission Reductions for Florida

	Current (2003) Power Plant Emissions (tons/year)	CAIR Phase 1 Emission Cap (tons/year)	EPA-Projected Phase 1 Emissions (tons/year)	CAIR Phase 2 Emission Cap (tons/year)	EPA-Projected Phase 2 Emissions (tons/year)
		2010 – 2014		*2015-on*	
SO_2	**475,000**	**253,450**	**218,000** *(54% reduction)*	**177,415**	**167,000** *(65% reduction)*
		2009 – 2014		*2015-on*	
NOx	**253,000**	**99,445**	**69,000** *(73% reduction)*	**82,871**	**61,000** *(76% reduction)*

CAIR Ozone Season (May through September) Emission Caps and Projected Emission Reductions for Florida

	Current (2003) Power Plant Emissions (tons/season)	CAIR Phase 1 Emission Cap (tons/season)	EPA-Projected Phase 1 Emissions (tons/season)	CAIR Phase 2 Emission Cap (tons/season)	EPA-Projected Phase 2 Emissions (tons/season)
		2009 - 2014		*2015-on*	
NOx	**119,000**	**47,912**	**33,000** *(72% reduction)*	**39,926**	**29,000** *(76% reduction)*

<u>State Rule Development Process</u>

The DEP Division of Air Resource Management held two conceptual workshops (November 29, 2005, and March 2, 2006) and one official rulemaking workshop (April 13, 2006) to present options for implementing CAIR in Florida and to provide opportunities for public comment. Following each workshop, comments received by the division were posted on its website for review by all participants in the rulemaking process and other interested parties.

The focus of the workshops was on development of a Florida methodology for allocating annual and ozone-season NOx allowances to the state's EGUs, the principle area of flexibility provided to the state under the EPA cap-and-trade model rules. Even though the statewide NOx caps are fixed, different allocation methods give rise to different allowance amounts for individual units and utilities. Since allowances have monetary value, each utility tended to favor the allocation method that provided it with the greatest number of allowances.

While all Florida utilities supported the DEP's proposal to opt-in to the CAIR cap-and-trade programs for annual and ozone season NOx emissions, the utilities were unable to reach agreement among themselves on a preferred methodology for allocating NOx allowances to individual EGUs. During the course of the rule development process, several different methodologies for allocating NOx allowances were put forward by the various stakeholders. The major issues were:

- Allocation methodology for existing units: fuel-neutral vs. fuel-adjusted
- Allocation methodology for new units: input-based vs. output-based
- Baseline period for allocations: updating vs. fixed

Each of these issues is summarized below.

Allocation Methodology for Existing Units

Under the EPA model rules, existing units are allocated NOx allowances in proportion to their "fuel-adjusted heat input" during the baseline period. Fuel adjustment factors of 1.0, 0.6, and 0.4 are applied for coal, oil, and gas, respectively. Gas-fired turbines are more efficient than coal-fired boilers and emit less NOx per unit of heat input than a coal-fired boiler. Therefore, if NOx allowances are allocated on a "fuel-neutral heat input" basis (no fuel adjustment), an existing gas-fired turbine would receive more allowances relative to its actual NOx emissions than an existing coal-fired boiler. By design, the fuel adjustment factors shift some of a state's NOx allowances from existing oil and gas-fired units to existing coal-fired units in order to provide more allowances to units that face the greater burden in reducing emissions.

Utilities with mostly coal-fired plants argued that the additional allowances they would receive as a result of the fuel adjustment factors are appropriate to mitigate the costs of retrofitting their older ("grandfathered") units with modern air pollution control equipment—costs the gas-fired plants would not incur. On the other hand, utilities with mostly oil-fired and gas-fired plants argued that their customers are already paying for cleaner generation and should not lose the economic benefit of the additional allowances they would receive if no fuel factors were used.

Having considered these opposing points of view, the DEP decided to follow the EPA model rule approach of allocating NOx allowances to existing units on a fuel-adjusted heat input basis. In addition, the DEP developed a separate fuel factor of 1.5 for existing biomass-fired units that, despite use of the "best available control technology," would otherwise receive substantially fewer allowances than needed.

Allocation Methodology for New Units

As stated above, with a heat-input-based system, allowances are allocated in proportion to a unit's fuel usage during its baseline period. With an output-based system, allowances are allocated in proportion to a unit's gross electrical output during its baseline period. The output approach is "fuel neutral" and does not adjust allowances based on the type of fuel used to generate the electrical power.

The EPA model rules allocate allowances to new units using a "modified output" approach (also referred to as the "converted input" method). Under this approach, a unit's electrical output is converted to a nominal heat input value using factors that are designed to reward the use of more efficient technologies within fuel types; for example, it provides more NOx allowances to a new combined-cycle gas unit than to a new simple-cycle gas unit and more allowances to a new integrated gasification combined cycle (IGCC) coal unit than to a new pulverized coal unit. The conversion from output to heat input is necessary to allow new units, once they have established a baseline, to join the existing-unit pool and receive an appropriate pro-rata share of allowances.

The argument for an output-based system is that it favors construction of newer, more efficient units over continued operation of older, less-efficient units. However, some utilities argued that an output-based system inappropriately favors new gas units over new coal units because gas units receive more allowances than needed under the fuel-neutral, output-based approach.

To promote efficiency in the design and operation of future power plants, notwithstanding the choice of fuel, the DEP decided to follow the EPA model rule approach of allocating allowances to new units using the modified output methodology. However, to eliminate an unnecessary shift of allowances from pre-2001 units to already existing pre-2007 units, the DEP changed the definition of "existing unit" to include units commencing operation prior to 2007, rather than 2001 as proposed by EPA.

Updating vs. Fixed Baseline Period

With a fixed baseline period, the number of allowances a unit receives in future years will always be proportional to its level of operations over a fixed historical baseline period (e.g., 2000-2004), even if the unit is later operated at a higher or lower rate, or retired. An updating baseline system keeps the distribution of allowances more closely aligned with actual plant operations in future years by resetting the baseline period for all units on a periodic basis.

Some utilities favored an updating system to prevent inequities in the distribution of future allowances from developing between utilities that experience different rates of demand growth in their respective service areas. Other utilities argued that a fixed baseline provides more certainty for future planning and also encourages early retirement of older units since the utility would continue to receive allowances for such units indefinitely.

To provide more certainty for planning, the DEP decided to follow the EPA model rule approach of using a fixed baseline period. However, to provide a somewhat more equitable distribution of future allowances, the DEP adopted a provision that allows retired units to receive allowances for 10-12 years after they cease operation, after which their allowances will be redistributed to active units.

After considering the stakeholder input received during the workshop process, DEP developed proposed rules for implementing CAIR in Florida. By state law, the proposed rules were required to be approved by Florida's Environmental Regulation Commission (ERC) in a public hearing. The DEP briefed the ERC on the proposed rules on May 25, 2006, published notices of proposed rulemaking in the Florida Administrative Weekly on May 26, 2006, and presented the rules to the ERC at a public hearing held June 29, 2006, in Tallahassee.

The ERC public hearing also served as the public hearing required by 40 CFR 51.102 for a proposed SIP revision. Accordingly, DEP complied with all pre-hearing notification requirements of 40 CFR 51.102 prior to the ERC hearing. For details, see the "Response to 40 CFR 51.102 Requirements" section of this SIP submittal.

Response to EPA and Public Comments

Comments on the DEP's proposed rules to implement CAIR were received into the hearing record from EPA Region 4, Florida Power & Light Company (FPL), Cedar Bay Generating Company, and Indiantown Cogeneration. EPA and FPL included specific recommendations for rule language changes. Copies of these comment letters are provided in the "Public Comments" section of this submittal. DEP responded to all of the comments in its rule adoption memo to the ERC (see "Public Hearing" section of this submittal). The responses are summarized below.

EPA Comments and DEP Response

EPA offered several rule language changes to improve clarity. EPA also recommended that the citation to federal rules adopted by reference not include the Federal Register cover page.

In all other adoptions by reference, it has been DEP's practice to cite to the cover page, so no change was made in response to this comment. DEP concurred with all of the remaining changes recommended by EPA and offered them to the ERC as proposed amendments to the rules as noticed. The DEP's proposed rule amendment forms are included in the "Public Hearing" section of this submittal.

FPL Comments and DEP Response

FPL asked the ERC to reject the DEP proposal that fuel factors be used for allocating NOx allowances to existing coal, oil, and gas-fired EGUs. Instead, FPL offered a proposed rule amendment that would base the NOx allocation methodology for existing fossil-fuel fired EGUs on the units' unadjusted baseline heat inputs.

While understanding FPL's position, DEP defended its proposal on the basis that the state's existing coal-fired units will bear the brunt of the emission reductions needed for Florida to comply with CAIR and, therefore, should receive more allowances to help defray the costs of upgrading their units to achieve the needed NOx reductions. In taking this position, the DEP acknowledged that it was giving more weight to the costs that utilities must incur to comply with CAIR than to any technology or fuel-related decisions utilities may have made prior to CAIR and independent of its requirements.

Cedar Bay Generating and Indiantown Cogeneration Comments and DEP Response

Both companies recommended that the baseline period be updated on a regular basis (e.g., every five years), rather than fixed permanently, so that allocations more accurately reflect current operations.

DEP defended its proposal on the basis that the greater certainty provided by a fixed baseline period is important in the early years of the program. A decision to move to an updating baseline approach could be made at a later time, if the need to do so becomes more apparent.

Rule Adoption

At the June 29, 2006, public hearing, the ERC approved the proposed CAIR implementation rules as noticed by DEP on May 26, 2006, with the rule language amendments recommended by EPA and concurred with by DEP as noted above. The ERC did not act on the FPL proposed amendments or on the comments offered by Cedar Bay Generation and Indiantown Cogeneration. Details of the hearing are located in the "Public Hearing" section of this submittal under the "Excerpt of ERC Hearing Minutes" tab. On July 21, 2006, DEP published "Notices of Change," showing the rule language amendments approved by the ERC at the public hearing

On August 10, 2006, FPL filed a petition challenging DEP's proposed adoption of the rules approved by the ERC, to the extent such rules employed fuel adjustment factors to allocate annual and ozone-season NOx allowances to existing fossil-fuel fired EGUs. The section of the rule related to the NOx allowance allocation methodology could not be adopted until the rule challenge was resolved. As a result, the department adopted the remaining rule sections, effective September 4, 2006, and proceeded to an administrative hearing on the challenged portions on November 14, 2006.

On March 1, 2007, the administrative law judge entered a final order on the case, upholding the DEP rule as approved by the ERC. Subsequently, DEP adopted the challenged portions of the rule, effective April 1, 2007, completing its adoption of the rule amendments comprising this proposed SIP revision.

Summary of Rules

Coded (underline/strike-through) copies of the adopted DEP rules may be found at the "Materials to be Incorporated into SIP" section of this submittal. Complete rule chapters, as amended, may be found at the "Rule Chapters as Amended" section. The amendments to each rule chapter are summarized below.

Rule 62-204.800, F.A.C., Federal Regulations Adopted by Reference

Rule 62-204.800, F.A.C, is amended to adopt and incorporate by reference the EPA CAIR model rules at 40 CFR Part 96 and related EPA regulations at 40 CFR Parts 72, 73, 77, and 78. As stated in the lead-in text of the rule section, the purpose and effect of each federal regulation adopted by reference is determined by the context in which it is cited elsewhere in the rules. The federal regulations adopted by reference in Rule 62-204.800, F.A.C., as part of the CAIR rulemaking project are cited and given context in the CAIR-related amendments to Chapters 62-210 and 62-296, F.A.C. The DEP-adopted changes to the EPA model-rule allowance allocation methodology are set forth in the amendments to Chapter 62-296, F.A.C.

Rule 62-210.200, F.A.C., Definitions

Rule 62-210.200, F.A.C, is amended to add 16 new definitions and revise two existing definitions. Some of these definitions are used in Chapter 62-296, F.A.C., in provisions that are not part of the DEP changes to the EPA CAIR model rules. Others will be used in proposed CAIR-related amendments to the state's Title V permitting rules for which a notice of proposed rulemaking has not yet been published. The Title V rule amendments will be adopted following submission of this SIP revision.

Rule 62-296.470, F.A.C., Implementation of Federal Clean Air Interstate Rule

New Rule 62-296.470, F.A.C., is the heart of the DEP's rulemaking project related to CAIR implementation. In this rule section, the state sets forth its alternative methodology for distributing NOx allowances to its EGUs. It does so by adopting "substitute language" to be used in applying the EPA CAIR model rules in Florida. The substitute language modifies the EPA model-rule allocation method as allowed pursuant to 40 CFR 51.123(o)(2) and (aa)(2). A copy of the text of 40 CFR Part 96, Subparts EE and EEEE, showing how it would read with the DEP substitute language is provided in Exhibit 2 to this Executive Summary.

Statutory Authority

Section 403.061(35), Florida Statutes, authorizes the DEP to "exercise the duties, powers, and responsibilities required of the state under the federal Clean Air Act." These duties and responsibilities include the development and periodic updating of Florida's SIP. The rule amendments to implement CAIR were adopted pursuant to this specific statutory authority.

Nitrogen Oxides Allowance Allocations

Rule 62-296.470, F.A.C., requires the department to issue a state administrative order allocating annual and ozone-season NOx allowances to EGUs prior to transmitting such allocations to EPA for recordation in the utilities' trading accounts. After April 1, 2007, the department plans to issue its initial administrative order allocating NOx allowances to the state's CAIR-affected EGUs for the control years 2009, 2010, 2011, and 2012. A copy of this draft administrative order is provided in Exhibit 3 to this Executive Summary.

A state's methodology for distributing NOx allowances is approvable by EPA as long as the state allocates its allowances by certain prescribed dates and imposes no restrictions on their use for trading or banking within the EPA-administered system. EPA does not require the state to allocate a minimum number of allowances to any EGU or to allocate allowances based on fuel usage, electrical output, or any other such system. Therefore, the department believes its allocation method, as implemented through the rules comprising this SIP revision, and demonstrated in practice at Exhibit 3, is fully approvable.

As additional information, Exhibit 4 to this Executive Summary provides an analysis of alternative NOx allocation methodologies that were examined by DEP during the CAIR rule development process.

Subpart EE – CAIR NOx Allowance Allocations

§ 96.140 State trading budgets.

The State trading budgets for annual allocations of CAIR NOx allowances for the control periods in 2009 through 2014 and in 2015 and thereafter are respectively as follows:

	State trading budget for 2009-2014 (tons)	State trading budget for 2015 and thereafter (tons)
Florida	99,445	82,871

§ 96.141 Timing requirements for CAIR NOx allowance allocations.

(a) By October 31, 2006, the permitting authority will submit to the Administrator the CAIR NOx allowance allocations, in a format prescribed by the Administrator and in accordance with sections 96.142(a) and (b), for the control periods in 2009, 2010, 2011, and 2012.

(b) By October 31, 2009, and October 31 of each third year thereafter, the permitting authority will submit to the Administrator the CAIR NOx allowance allocations, in a format prescribed by the Administrator and in accordance with sections 96.142(a) and (b), for the control periods in the fourth, fifth, and sixth years after the year of the applicable deadline for submission under this paragraph.

(c) By October 31, 2009, and October 31 of each year thereafter, the permitting authority will submit to the Administrator the CAIR NOx allowance allocations, in a format prescribed by the Administrator and in accordance with sections 96.142(a), (c), and (d), for the control period in the year of the applicable deadline for submission under this paragraph.

§ 96.142 CAIR NOx allowance allocations.

(a)(1) The baseline heat input (in MMBtu) used with respect to CAIR NOx allowance allocations under paragraph (b) of this section for each CAIR NOx unit will be:

(i) For units commencing operation before January 1, 2000: the average of the 3 highest amounts of the unit's adjusted control period heat input for 2000 through 2004; for units commencing operation on or after January 1, 2000, and before January 1, 2007, and operating for at least one full calendar year: the average of the 3 highest amounts of the unit's adjusted control period heat input over the unit's first 5 full years of operation, or the average of the 2 highest amounts of the unit's adjusted control period heat input over its first 4 full years of operation, or the maximum adjusted control period heat input over the unit's first 1 to 3 full years of operation, depending on the number of full years of operating data available to the permitting authority for determination of allowance allocations pursuant to sections 96.141(a) or 96.141(b)(1); with the adjusted control period heat input for each year calculated as follows:

(A) If the unit is 85 percent or more (on a Btu basis) biomass-fired during the year and is subject to best available control technology (BACT) for NOx emissions, the unit's control period heat input for such year is multiplied by 150 percent;

(B) If the unit is coal-fired during the year, the unit's control period heat input for such year is multiplied by 100 percent;

(C) 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

(D) If the unit is not subject to paragraph (a)(1)(i)(A), (B), or (C) 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, 2007, and operating for at least one full calendar year: the average of the 3 highest amounts of the unit's total converted control period heat input over the unit's first 5 full years of operation, or the average of the 2 highest amounts of the unit's total converted control period heat input over its first 4 full years of operation, or the maximum total converted control period heat input over the unit's first 1 to 3 full years of operation, depending on the number of full years of operating data available to the permitting authority for determination of allowance allocations pursuant to sections 96.141(a) or 96.141(b)(1).

(iii) For any unit that is permanently retired and has not operated during the most recent five-year period for which the permitting authority has data upon which to base allocations: zero (0).

(2)(i) A unit's control period heat input, and a unit's status as biomass-fired, coal-fired or oil-fired, for a calendar year under paragraph (a)(1)(i) of this section, and a unit's total tons of NOx 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 biomass-fired (85 percent or more on a Btu basis) for the year, 7,900 Btu/kWh if the unit is coal-fired for the year, or 6,675 Btu/kWh if the unit is not biomass-fired or 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 3,413 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 NOx units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of CAIR NOx allowances equal to 95 percent of the tons of NOx emissions in the State trading budget under section 96.140 (except as provided in paragraph (d) of this section).

(2) The permitting authority will allocate CAIR NOx allowances to each CAIR NOx unit under paragraph (b)(1) of this section in an amount determined by multiplying the total amount of CAIR NOx allowances allocated under paragraph (b)(1) of this section by the ratio of the baseline heat input of such CAIR NOx unit to the total amount of baseline heat input of all such CAIR NOx 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 NOx allowances to CAIR NOx units in a State that are not allocated CAIR NOx allowances under paragraph (b) of this section because the units do not yet have a baseline heat input under paragraph (a) of this section or because the units have a baseline heat input but all CAIR NOx allowances available under paragraph (b) of this section for the control period are already allocated, in accordance with the following procedures:

(1) <u>The permitting authority will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated CAIR NOx allowances equal to 5 percent of the amount of tons of NOx emissions in the State trading budget under section 96.140, adjusted as necessary to ensure that the sum of all allocations made by the permitting authority does not exceed the State trading budget.</u>

(2) The CAIR designated representative of such a CAIR NOx unit may submit to the permitting authority a request, in a format specified by the permitting authority, to be allocated CAIR NOx allowances, starting with the later of the control period in 2009 or the first control period after the control period in which the CAIR NOx unit commences commercial operation and until the first control period for which the unit is allocated CAIR NOx allowances under paragraph (b) of this section. A separate CAIR NOx allowance allocation request for each control period for which CAIR NOx allowances are sought must be submitted on or before May 1 of such control period; and after the date on which the CAIR NOx unit commences commercial operation.

(3) In a CAIR NOx allowance allocation request under paragraph (c)(2) of this section, the CAIR designated representative may request for a control period CAIR NOx allowances in an amount not exceeding the CAIR NOx unit's total tons of NOx emissions during the calendar year immediately before such control period.

(4) The permitting authority will review each CAIR NOx allowance allocation request under paragraph (c)(2) of this section and will allocate CAIR NOx 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 May 1 of the control period, the permitting authority will determine the sum of the CAIR NOx 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 NOx 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 NOx allowances requested (as adjusted under paragraph (c)(4)(i) of this section) to each CAIR NOx unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section.

(iv) If the amount of CAIR NOx 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 NOx unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the CAIR NOx allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of CAIR NOx 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 using such rounding convention that results in allocation of the precise number of allowances in the set-aside.

(v) The permitting authority will notify each CAIR designated representative that submitted an allowance allocation request of the amount of CAIR NOx allowances (if any) allocated for the control period to the CAIR NOx 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 NOx allowances remain in the new unit set-aside for the control period, the permitting authority will allocate to each CAIR NOx unit that was allocated CAIR NOx allowances under paragraph (b) of this section an amount of CAIR NOx allowances equal to the total amount of such remaining unallocated CAIR NOx allowances, multiplied by the unit's allocation under paragraph (b) of this section, divided by 95 percent of the amount of tons of NOx emissions in the State trading budget under section 96.140, and rounded to the nearest whole allowance using such rounding convention that results in allocation of the precise number of allowances remaining in the set-aside.

§ 96.143 Compliance supplement pool.

(a) The permitting authority will establish a separate compliance supplement pool for the control period in 2009 and will allocate CAIR NOx allowances equal to 8,335 tons to such pool. These allowances are in addition to the CAIR NOx allowances allocated under section 96.142.

(b) For any CAIR NOx unit in the State, if the unit's average annual NOx emission rate for 2007 or 2008 is less than 0.25 lb/mmBtu and, where such unit is included in a NOx averaging plan under section 76.11 of the chapter under the Acid Rain Program for such year, the unit's NOx averaging plan has an actual weighted average NOx emission rate for such year equal to or less than the actual weighted average NOx emission rate for the year before such year and if the unit achieves NOx emission reductions in 2007 and 2008, the CAIR designated representative of the unit may request early reduction credits, and allocation of CAIR NOx 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 NOx unit shall monitor and report the NOx 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 NOx unit shall submit to the permitting authority by May 1, 2009, a request, in a format specified by the permitting authority, for allocation of an amount of CAIR NOx allowances from the compliance supplement pool not exceeding the sum of the unit's heat input for the control period in 2007 multiplied by the difference (if any greater than zero) between 0.25 lb/mmBtu and the unit's NOx emission rate for the control period in 2007 plus the unit's heat input for the control period in 2008 multiplied by

the difference (if any greater than zero) between 0.25 lb/mmBtu and the unit's NOx emission rate for the control period in 2008, determined in accordance with subpart HH of this part and with the sum divided by 2,000 lb/ton and rounded to the nearest whole number of tons as appropriate.

(c) For any CAIR NOx unit in the State whose compliance with CAIR NOx 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 NOx 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 NOx unit shall submit to the permitting authority by May 1, 2009, a request, in a format specified by the permitting authority, for allocation of an amount of CAIR NOx allowances from the compliance supplement pool not exceeding the minimum amount of CAIR NOx allowances necessary to remove such undue risk to the reliability of electric supply.

(2) In the request under paragraph (c)(1) of this section, the CAIR designated representative of such CAIR NOx unit shall demonstrate that, in the absence of allocation to the unit of the amount of CAIR NOx allowances requested, the unit's compliance with CAIR NOx 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 NOx 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 NOx allowances to prevent such undue risk.

(d) The permitting authority will review each request under paragraph (b) or (c) of this section submitted by May 1, 2009 and will allocate CAIR NOx allowances for the control period in 2009 to CAIR NOx 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 NOx 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 NOx allowances not less than the total amount of CAIR NOx allowances in all such requests (as adjusted under paragraph (d)(1) of this section), the permitting authority will allocate to each CAIR NOx unit covered by such requests the amount of CAIR NOx 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 NOx allowances than the total amount of CAIR NOx allowances in all such requests (as adjusted under paragraph (d)(1) of this section), the permitting authority will allocate CAIR NOx allowances to each CAIR NOx 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 amount of CAIR NOx allowances allocated to the unit from the State's compliance supplement pool. "Unit's adjusted allocation" is the amount of CAIR NOx 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 NOx 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) (2) or (3) of this section.

(5) By January 1, 2010, the Administrator will record the allocations under paragraph (d) (4) of this section.

Subpart EEEE – CAIR NOx 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 NOx Ozone Season allowances for the control periods in 2009 through 2014 and in 2015 and thereafter are respectively as follows:

	State trading budget for 2009-2014 (tons)	State trading budget for 2015 and thereafter (tons)
Florida	47,912	39,926

(b) If a permitting authority issues additional CAIR NOx 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 NOx Ozone Season allowance allocations issued under § 51.123 (aa)(2)(iii)(A) of this chapter for the year.

§ 96.341 Timing requirements for CAIR NOx Ozone Season allowance allocations.

(a) By October 31, 2006, the permitting authority will submit to the Administrator the CAIR NOx Ozone Season allowance allocations, in a format prescribed by the Administrator and in accordance with sections 96.342(a) and (b), for the control periods in 2009, 2010, 2011, and 2012.

(b) By October 31, 2009, and October 31 of each third year thereafter, the permitting authority will submit to the Administrator the CAIR NOx Ozone Season allowance allocations, in a format prescribed by the Administrator and in accordance with sections 96.342(a) and (b), for the control periods in the fourth, fifth, and sixth years after the year of the applicable deadline for submission under this paragraph.

(c) By July 1, 2009, and July 31 of each year thereafter, the permitting authority will submit to the Administrator the CAIR NOx Ozone Season allowance allocations, in a format prescribed by the Administrator and in accordance with sections 96.342(a), (c), and (d), for the control period in the year of the applicable deadline for submission under this paragraph.

§ 96.342 CAIR NOx Ozone Season allowance allocations.

(a)(1) The baseline heat input (in mmBtu) used with respect to CAIR NOx Ozone Season allowance allocations under paragraph (b) of this section for each CAIR NOx Ozone Season unit will be:

(i) For units commencing operation before January 1, 2000: the average of the 3 highest amounts of the unit's adjusted control period heat input for 2000 through 2004; for units commencing operation on or after January 1, 2000, and before January 1, 2007, and operating for at least one full calendar year: the average of the 3 highest amounts of the unit's adjusted control period heat input over the unit's first 5 full years of operation, or the average of the 2 highest amounts of the unit's adjusted control period heat input over its first 4 full years of operation, or the maximum adjusted control period heat input over the unit's first 1 to 3 full years of operation, depending on the number of full years of operating data available to the permitting authority for determination of allowance allocations pursuant to sections 96.341(a) or 96.341(b)(1); with the adjusted control period heat input for each year calculated as follows:

(A) If the unit is 85 percent or more (on a Btu basis) biomass-fired during the year and is subject to best available control technology (BACT) for NOx emissions, the unit's control period heat input for such year is multiplied by 150 percent;

(B) If the unit is coal-fired during the year, the unit's control period heat input for such year is multiplied by 100 percent;

(C) 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

(D) If the unit is not subject to paragraph (a)(1)(i)(A), (B), or (C) 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, 2007, and operating for at least one full calendar year: the average of the 3 highest amounts of the unit's total converted control period heat input over the unit's first 5 full years of operation, or the average of the 2 highest amounts of the unit's total converted control period heat input over its first 4 full years of operation, or the maximum total converted control period heat input over the unit's first 1 to 3 full years of operation, depending on the number of full years of operating data available to the permitting authority for determination of allowance allocations pursuant to sections 96.341(a) or 96.341(b)(1).

(iii) For any unit that is permanently retired and has not operated during the most recent five-year period for which the permitting authority has data upon which to base allocations: zero (0).

(2)(i) A unit's control period heat input, and a unit's status as biomass-fired, coal-fired or oil-fired, for a calendar year under paragraph (a)(1)(i) of this section, and a unit's total tons of NOx emissions during a control period in 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 biomass-fired (85 percent or more on a Btu basis) for the year, 7,900 Btu/kWh if the unit is coal-fired for the year, or 6,675 Btu/kWh if the unit is not biomass-fired or 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 3,413 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 NOx 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 NOx allowances equal to 95 percent of the tons of NOx emissions in the State trading budget under section 96.340 (except as provided in paragraph (d) of this section).

(2) The permitting authority will allocate CAIR NOx Ozone Season allowances to each CAIR NOx Ozone Season unit under paragraph (b)(1) of this section in an amount determined by multiplying the total amount of CAIR NOx Ozone Season allowances allocated under paragraph (b)(1) of this section by the ratio of the baseline heat input of such CAIR NOx Ozone Season unit to the total amount of baseline heat input of all such CAIR NOx 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 NOx Ozone Season allowances to CAIR NOx Ozone Season units in a State that are not allocated CAIR NOx Ozone Season allowances under paragraph (b) of this section because the units do not yet have a baseline heat input under paragraph (a) of this section or because the units have a baseline heat input but all CAIR NOx Ozone Season allowances available under paragraph (b) of this section for the control period are already allocated, 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 NOx Ozone Season allowances equal to 5 percent of the amount of tons of NOx emissions in the State trading budget under section 96.340, adjusted as necessary to ensure that the sum of all allocations made by the permitting authority does not exceed the State trading budget.

(2) The CAIR designated representative of such a CAIR NOx Ozone Season unit may submit to the permitting authority a request, in a format specified by the permitting authority, to be allocated CAIR NOx 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 NOx Ozone Season unit commences commercial operation and until the first control period for which the unit is allocated CAIR NOx Ozone Season allowances under paragraph (b) of this section. A separate CAIR NOx Ozone Season allowance allocation request for each control period for which CAIR NOx allowances are sought must be submitted on or before February 1 of such control period. and after the date on which the CAIR NOx Ozone Season unit commences commercial operation.

(3) In a CAIR NOx Ozone Season allowance allocation request under paragraph (c)(2) of this section, the CAIR designated representative may request for a control period CAIR NOx Ozone Season allowances in an amount not exceeding the CAIR NOx Ozone Season unit's total tons of NOx emissions during the control period immediately before such control period.

(4) The permitting authority will review each CAIR NOx Ozone Season allowance allocation request under paragraph (c)(2) of this section and will allocate CAIR NOx 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 February 1 before the control period, the permitting authority will determine the sum of the CAIR NOx 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 NOx 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 NOx Ozone Season allowances requested (as adjusted under paragraph (c)(4)(i) of this section) to each CAIR NOx Ozone Season unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section.

(iv) <u>If the amount of CAIR NOx 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</u>

permitting authority will allocate to each CAIR NOx Ozone Season unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the CAIR NOx Ozone Season allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of CAIR NOx 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 using such rounding convention that results in allocation of the precise number of allowances in the set-aside.

(v) The permitting authority will notify each CAIR designated representative that submitted an allowance allocation request of the amount of CAIR NOx Ozone Season allowances (if any) allocated for the control period to the CAIR NOx 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 NOx Ozone Season allowances remain in the new unit set-aside for the control period, the permitting authority will allocate to each CAIR NOx Ozone Season unit that was allocated CAIR NOx Ozone Season allowances under paragraph (b) of this section an amount of CAIR NOx Ozone Season allowances equal to the total amount of such remaining unallocated CAIR NOx Ozone Season allowances, multiplied by the unit's allocation under paragraph (b) of this section, divided by 95 percent of the amount of tons of NOx emissions in the State trading budget under section 96.340, and rounded to the nearest whole allowance using such rounding convention that results in allocation of the precise number of allowances remaining in the set-aside.

62-210.200 Definitions. The following words and phrases when used in this chapter and in Chapters 62-212, 62-213, 62-214, 62-296, and 62-297, F.A.C., shall, unless content clearly indicates otherwise, have the following meanings:

(1) through (23) No change.

(24) "Alternate Designated Representative" –

(a) For the purposes of the Acid Rain Program, alternate designated representative shall mean "alternate designated representative" as described in 40 CFR 72.22, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(b) For the purposes of the CAIR Program, alternate designated representative shall mean "alternate CAIR designated representative" as defined in 40 CFR 96.102, 96.202, or 96.302, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(24) through (40) renumbered as (25) through (41) No change.

(42) "Biomass" – Vegetative matter and untreated wood.

(41) through (48) renumbered as (43) through (50) No change.

(51) "CAIR" – Abbreviation for federal Clean Air Interstate Rule.

(52) "CAIR NOx Allowance" - A limited authorization issued by the Department pursuant to Rule 62-296.470, F.A.C., 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 NOx Annual Trading Program.

(53) "CAIR NOx Annual Trading Program" – The program implemented at subsection 62-296.470(3), F.A.C., which, upon approval by the U.S. Environmental Protection Agency, requires CAIR NOx units in Florida to participate in the multi-state air pollution control and emission reduction program administered by the U.S. Environmental Protection Agency pursuant to 40 CFR Part 96, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(54) "CAIR NOx Ozone Season Allowance" - A limited authorization issued by the Department pursuant to Rule 62-296.470, F.A.C., 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 NOx Ozone Season Trading Program.

(55) "CAIR NOx Ozone Season Trading Program" – The program implemented at subsection 62-296.470(5), F.A.C., which, upon approval by the U.S. Environmental Protection Agency, requires CAIR NOx Ozone Season units in Florida to participate in the multi-state air pollution control and emission reduction program administered by the U.S. Environmental Protection Agency pursuant to 40 CFR Part 96, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(56) "CAIR NOx Ozone Season Unit" – A unit that is subject to the CAIR NOx Ozone Season Trading Program pursuant to 40 CFR 96.304, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(57) "CAIR NOx Unit" – A unit that is subject to the CAIR NOx Annual Trading Program pursuant to 40 CFR 96.104, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(58) "CAIR Part or CAIR Permit" – That portion of the Title V source permit specifying the CAIR Program requirements applicable to a CAIR source, to each CAIR unit at the source, and to the owners and operators and the CAIR designated representative of the CAIR source and each such CAIR unit.

(59) "CAIR Program" – Any or all of the following:

(a) CAIR NOx Annual Trading Program;

(b) CAIR SO_2 Trading Program; or

(c) CAIR NOx Ozone Season Trading Program

(60) "CAIR SO_2 Allowance" - A limited authorization issued by the Administrator under the Acid Rain Program 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.

(61) "CAIR SO_2 Trading Program" – The program implemented at subsection 62-296.470(4), F.A.C., which, upon approval by the U.S. Environmental Protection Agency, requires CAIR SO_2 units in Florida to participate in the multi-state air pollution control and emission reduction program administered by the U.S. Environmental Protection Agency pursuant to 40 CFR Part 96, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(62) "CAIR SO_2 Unit" – A unit that is subject to the CAIR SO_2 Trading Program pursuant to 40 CFR 96.204, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(63) "CAIR Source" – A facility that includes one or more CAIR units.

(64) "CAIR Unit" –

(a) A CAIR NOx unit;

(b) A CAIR SO_2 unit; or

(c) A CAIR NOx Ozone Season unit.

(49) through (71) renumbered as (65) through (87) No change.

(88)~~(72)~~ "Commence Operation" –

(a) No change.

(b) For the purposes of the CAIR Program, commence operation shall mean "commence operation" as defined in 40 CFR 96.102, 96.202, or 96.302, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(c)~~(b)~~ Otherwise, to set into operation any emissions unit for any purpose.

(73) through (94) renumbered as (89) through (110) No change.

(111)~~(95)~~ "Designated Representative" –

(a) For the purposes of the Acid Rain Program, a~~A~~ responsible natural person authorized, by the owners and operators of an Acid Rain source and of all Acid Rain units at the source, in accordance with 40 C.F.R. Part 72, Subpart B, adopted and incorporated by reference in ~~into~~ Rule 62-204.800, F.A.C., to represent and legally bind each owner and operator, as a matter of federal law, in matters pertaining to the Acid Rain Program.

(b) For the purposes of the CAIR Program, designated representative shall mean "CAIR designated representative" as defined in 40 CFR 96.102, 96.202, or 96.302, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(96) through (296) renumbered as (112) through (312) No change.

Specific Authority 403.061, 403.8055, FS. Law Implemented 403.031, 403.061, 403.087, 403.8055, FS. History-Formerly 17-2.100; Amended 2-9-93, 11-28-93, Formerly 17-210.200, Amended 11-23-94, 4-18-95, 1-2-96, 3-13-96, 3-21-96, 8-15-96, 10-7-96, 10-15-96, 5-20-97, 11-13-97, 2-5-98, 2-11-99, 4-16-01, 2-19-03,4-1-05, 7-6-05, 2-2-06, 4-1-06, ________.

Florida Department of
Environmental Protection
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

March 16, 2007

Mr. James I. Palmer, Jr.
Regional Administrator
United States Environmental
Protection Agency - Region 4
61 Forsyth Street, SW
Atlanta, Georgia 30303-8909

Re: Air Program: Proposed Revision to State Implementation Plan (SIP) – Implementation of Clean Air Interstate Rule (CAIR)

Dear Mr. Palmer:

In accordance with the requirements of 40 CFR 51.103 and 51.104, and on behalf of the Governor of Florida, I am pleased to submit the subject proposed revision to Florida's State Implementation Plan (SIP) under the Clean Air Act. The proposed SIP revision consists of amendments to Florida Administrative Code Chapters 62-204, 62-210, and 62-296. The rule amendments are intended to implement the U.S. Environmental Protection Agency (EPA) Clean Air Interstate Rule (CAIR) as it applies to electric generating units (EGUs) in Florida. One hard copy and one electronic copy (compact disk) of the complete submittal package have been sent directly to the Air Planning Branch.

The state rules comprising this submittal were approved by Florida's Environmental Regulation Commission (ERC) at a public hearing in Tallahassee, Florida, on June 29, 2006. On August 10, 2006, a petition challenging certain portions of these rules was filed by a Florida utility. On March 1, 2007, the rules as originally approved by the ERC were upheld by a state Administrative Law Judge, thus clearing the way for the Department of Environmental Protection (DEP) to complete its adoption of the CAIR-related rules comprising this proposed SIP revision. I hereby certify that the public notice and hearing requirements of all applicable state and federal regulations have been satisfied with respect to this submittal.

In the interest of expediting approval of this proposed SIP revision and enabling Florida to allocate vintage-2009 and later nitrogen oxides (NOx) allowances to its EGUs in accordance with the methodology contained in the state's rules, we respectfully request that the DEP rules set forth in the table below initially be approved pursuant to EPA's abbreviated SIP approval process. We further request that these and all remaining rules comprising this SIP submittal ultimately be approved as a full SIP revision, replacing the initially approved abbreviated SIP. The DEP rules listed in the table implement the EPA CAIR model rules at 40 CFR Part 96, either verbatim or with only such changes as are allowed pursuant to 40 CFR 51.123(o)(2) and (aa)(2).

Mr. James I. Palmer, Jr.
Page 2
March 16, 2007

Florida Rules Submitted for Approval Pursuant to Abbreviated SIP Process.

Rule Citation	Description
62-204.800(25), F.A.C.	Adopts and incorporates by reference all applicable provisions of 40 CFR Part 96, as amended up to April 28, 2006. Note: DEP is in process of adopting by reference the December 13, 2006, amendments, to be effective April 1, 2007.
62-296.470(1), F.A.C.	Definitions. Clarifies that all provisions of 40 CFR Part 96 cited within Rule 62-296.470, F.A.C., are adopted and incorporated by reference at Rule 62-204.800, F.A.C. Clarifies that the definitions contained within 40 CFR Part 96, Subparts AA, AAA, & AAAA shall apply for purposes of the verbatim application of the cited provisions of 40 CFR Part 96.
62-296.470(3), F.A.C.	CAIR NO_X Annual Trading Program. Requires the verbatim application of all provisions of 40 CFR Part 96, Subparts AA through HH, except that DEP "substitute language" is inserted in Subpart EE, as allowed pursuant to 40 CFR 51.123(o)(2).
62-296.470(4), F.A.C.	CAIR SO_2 Trading Program. Requires the verbatim application of all provisions of 40 CFR Part 96, Subparts AAA through HHH.
62-296.470(5), F.A.C.	CAIR NO_X Ozone Season Trading Program. Requires the verbatim application of all provisions of 40 CFR Part 96, Subparts AAAA through HHHH, except that DEP "substitute language" is inserted in Subpart EEEE, as allowed pursuant to 40 CFR 51.123(aa)(2).

Thank you for your continued support of our efforts to fully implement CAIR in Florida.

Sincerely,

Joseph Kahn, Director
Division of Air Resource Management

JK/ls

cc: Mimi Drew, Deputy Secretary, DEP (letter only)
Kay Prince, Chief, Air Planning Branch, EPA Region 4 (with enclosures)

62-204.800 Federal Regulations Adopted by Reference. All federal regulations cited throughout the air pollution rules of the Department are adopted and incorporated by reference in this rule. The purpose and effect of each such federal regulation is determined by the context in which it is cited. Procedural and substantive requirements in the incorporated federal regulations are binding as a matter of state law only where the context so provides.

(1) through (15) No change.

(16) Chapter 40, Code of Federal Regulations, Part 72, Permits Regulation.

(a) The following subparts of 40 CFR Part 72, revised as of July 1, 2005 ~~July 1, 2001~~, or later as specifically indicated, are adopted and incorporated by reference:

1. 40 CFR 72, Subpart A, Acid Rain Program General Provisions; amended April 28, 2006, at 71 FR 25327 ~~August 15, 2001, at 66 FR 42761; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503 amended May 18, 2005, at 70 FR 28605~~.

2. 40 CFR 72, Subpart B, Designated Representative; amended April 28, 2006, at 71 FR 25327.

3. 40 CFR 72, Subpart C, Acid Rain Permit Applications.

4. 40 CFR 72, Subpart D, Acid Rain Compliance Plan and Compliance Options.

5. 40 CFR 72, Subpart E, Acid Rain Permit Contents.

6. 40 CFR 72, Subpart F, Federal Acid Rain Permit Issuance Procedures.

7. 40 CFR 72, Subpart G, Acid Rain Phase II Implementation.

8. 40 CFR 72, Subpart H, Permit Revisions.

9. 40 CFR 72, Subpart I, Compliance Certification.

(b) The following appendices of 40 CFR Part 72, revised as of July 1, 2005 ~~July 1, 2001~~, or later as specifically indicated, are adopted and incorporated by reference:

1. Appendix A, Methodology for Annualization of Emissions Limits.

2. Appendix B, Methodology for Conversion of Emissions Limits.

3. Appendix C, Actual 1985 Yearly SO2 Emissions Calculation.

4. Appendix D, Calculation of Potential Electric Output Capacity.

(17) Chapter 40, Code of Federal Regulations, Part 73, Sulfur Dioxide Allowance System. The following subparts of 40 CFR Part 73, revised as of July 1, 2005 ~~July 1, 2001~~, or later as specifically indicated, are adopted and incorporated by reference:

(a) 40 CFR 73, Subpart A, Background and Summary.

(b) 40 CFR 73, Subpart B, Allowance Allocations.

(c) 40 CFR 73, Subpart C, Allowance Tracking System; amended April 28, 2006, at 71 FR 25327.

(d) 40 CFR 73, Subpart D, Allowance Transfers.

(e) 40 CFR 73, Subpart E, Auctions, Direct Sales, and Independent Power Producers Written Guarantee.

(f) 40 CFR 73, Subpart F, Energy Conservation and Renewable Energy Reserve.

(g) 40 CFR 73, Subpart G, Small Diesel Refineries.

(18) through (19) No change.

(20) Chapter 40, Code of Federal Regulations, Part 77, Excess Emissions. The provisions of 40 CFR Part 77, Sections 77.1 through 77.6, revised as of July 1, 2005 ~~July 1, 2001~~, are adopted and incorporated by reference.

(21) Chapter 40, Code of Federal Regulations, Part 78, Appeal Procedures for Acid Rain Program. The provisions of 40 CFR Part 78, Sections 78.1 through 78.20, revised as of July 1, 2005; ~~July 1, 2001,~~ amended April 28, 2006, at 71 FR 25327, are adopted and incorporated by reference.

(22) through (24) No change.

(25) Chapter 40, Code of Federal Regulations, Part 96, NOx Budget Trading Program for State Implementation Plans. The following subparts of 40 CFR Part 96, revised as of July 1, 2005, or later as specifically indicated, are adopted and incorporated by reference.

(a) Subpart AA, CAIR NOX Annual Trading Program General Provisions; amended April 28, 2006, at 71 FR 25327.

(b) Subpart BB, CAIR Designated Representative for CAIR NOX Sources; amended April 28, 2006, at 71 FR 25327.

(c) Subpart CC, Permits; amended April 28, 2006, at 71 FR 25327.

(d) Subpart EE, CAIR NOX Allowance Allocations; amended April 28, 2006, at 71 FR 25327.

(e) Subpart FF, CAIR NOX Allowance Tracking System; amended April 28, 2006, at 71 FR 25327.

(f) Subpart GG, CAIR NOX Allowance Transfers.

(g) Subpart HH, Monitoring and Reporting; amended April 28, 2006, at 71 FR 25327.

(h) Subpart AAA, CAIR SO_2 Trading Program General Provisions; amended April 28, 2006, at 71 FR 25327.

(i) Subpart BBB, CAIR Designated Representative for CAIR SO_2 Sources; amended April 28, 2006, at 71 FR 25327.

(j) Subpart CCC, Permits; amended April 28, 2006, at 71 FR 25327.

(k) Subpart FFF, CAIR SO_2 Allowance Tracking System; amended April 28, 2006, at 71 FR 25327.

(l) Subpart GGG, CAIR SO_2 Allowance Transfers; amended April 28, 2006, at 71 FR 25327.

(m) Subpart HHH, Monitoring and Reporting; amended April 28, 2006, at 71 FR 25327.

(n) Subpart AAAA, CAIR NOx Ozone Season Trading Program General Provisions; amended April 28, 2006, at 71 FR 25327.

(o) Subpart BBBB, CAIR Designated Representative for CAIR NOX Ozone Season Sources; amended April 28, 2006, at 71 FR 25327.

(p) Subpart CCCC, Permits; amended April 28, 2006, at 71 FR 25327; amended April 28, 2006, at 71 FR 25327.

(q) Subpart EEEE, CAIR NOX Ozone Season Allowance Allocations; amended April 28, 2006, at 71 FR 25327.

(r) Subpart FFFF, CAIR NOX Ozone Season Allowance Tracking System; amended April 28, 2006, at 71 FR 25327.

(s) Subpart GGGG, CAIR NOX Ozone Season Allowance Transfers.

(t) Subpart HHHH, Monitoring and Reporting; amended April 28, 2006, at 71 FR 25327.

Specific Authority 403.061, 403.8055 FS. Law Implemented 403.031, 403.061, 403.087, 403.8055 FS. History–New 3-13-96, Amended 6-25-96, 10-7-96, 10-17-96, 12-20-96, 4-18-97, 6-18-97, 7-7-97, 10-3-97, 12-10-97, 3-2-98, 4-7-98, 5-20-98, 6-8-98, 10-19-98, 4-1-99, 7-1-99, 9-1-99, 10-1-99, 4-1-00, 10-1-00, 1-1-01, 8-1-01, 10-1-01, 4-1-02, 7-1-02, 10-1-02, 1-1-03, 4-1-03, 10-1-03, 1-1-04, 4-1-04, 7-1-04, 10-1-04, 1-1-05, 4-1-05, 7-1-05, 10-1-05, 1-1-06, 4-1-06, ________.

62-296.470 Implementation of Federal Clean Air Interstate Rule.

(1) Definitions. For purposes of this rule, the terms "CAIR," "CAIR NOx allowance," "CAIR NOx Annual Trading Program," "CAIR NOx Ozone Season allowance," "CAIR NOx Ozone Season Trading Program," "CAIR NOx Ozone Season unit," "CAIR NOx unit," "CAIR SO_2 allowance," "CAIR SO_2 Trading Program," "CAIR source," and "CAIR unit," shall have the meanings given at Rule 62-210.200, F.A.C. All provisions of 40 CFR Part 96 cited within this rule are adopted and incorporated by reference in Rule 62-204.800, F.A.C. Notwithstanding the first sentence of this paragraph, for purposes of the verbatim application of the cited subparts of 40 CFR Part 96, as modified by the substitute language set forth in this rule, the definitions contained within 40 CFR Part 96, Subparts AA, AAA, and AAAA, shall apply, with the understanding that the term "permitting authority" shall mean the Department, the term "State" shall mean the State of Florida, the phrase "permitting authority's title V operating permits regulations" shall mean Chapter 62-213, F.A.C., and the terms "best available control technology (BACT)" and "biomass" shall have the meanings given at Rule 62-210.200, F.A.C.

(2) Orders.

(a) Prior to submitting any CAIR NOx allowance allocations to the Administrator pursuant to 40 CFR 96.141(a), (b), or (c), or 40 CFR 96.143, the Department shall issue an administrative order pursuant to Chapter 120, F.S., to all CAIR NOx sources giving notice and opportunity for hearing with regard to the amount of CAIR NOx allowances the Department intends to submit to the Administrator for each CAIR NOx unit.

(b) Prior to submitting any CAIR NOx Ozone Season allowance allocations to the Administrator pursuant to 40 CFR 96.341(a), (b), or (c), the Department shall issue an administrative order to all CAIR NOx sources giving notice and opportunity for hearing with regard to the amount of CAIR NOx Ozone Season allowances the Department intends to submit to the Administrator for each CAIR NOx Ozone Season unit.

(3) CAIR NOx Annual Trading Program. Except as otherwise provided herein, all provisions of the following subparts of 40 CFR Part 96 shall apply verbatim. The provisions of Subpart II, CAIR NOx Opt-In Units, shall not apply.

(a) Subpart AA, CAIR NOx Annual Trading Program General Provisions.

(b) Subpart BB, CAIR Designated Representative for CAIR NOx Sources.

(c) Subpart CC, Permits.

(d) (Reserved).

(e) Subpart FF, CAIR NOx Allowance Tracking System.

(f) Subpart GG, CAIR NOx Allowance Transfers.

(g) Subpart HH, Monitoring and Reporting

(4) CAIR SO_2 Trading Program. All provisions of the following subparts of 40 CFR Part 96 shall apply verbatim. The provisions of Subpart III, CAIR SO_2 Opt-In Units, shall not apply.

(a) Subpart AAA, CAIR SO_2 Trading Program General Provisions.

(b) Subpart BBB, CAIR Designated Representative for CAIR SO_2 Sources.

(c) Subpart CCC, Permits.

(d) Subpart FFF, CAIR SO_2 Allowance Tracking System.

(e) Subpart GGG, CAIR SO_2 Allowance Transfers.

(f) Subpart HHH, Monitoring and Reporting

(5) CAIR NOx Ozone Season Trading Program. Except as otherwise provided herein, all provisions of the following subparts of 40 CFR Part 96 shall apply verbatim. The provisions of Subpart IIII, CAIR NOx Ozone Season Opt-In Units, shall not apply.

(a) Subpart AAAA, CAIR NOx Ozone Season Trading Program General Provisions.

(b) Subpart BBBB, CAIR Designated Representative for CAIR NOx Ozone Season Sources.

(c) Subpart CCCC, Permits.

(d) (Reserved).

(e) Subpart FFFF, CAIR NOx Ozone Season Allowance Tracking System.

(f) Subpart GGGG, CAIR NOx Ozone Season Allowance Transfers.

(g) Subpart HHHH, Monitoring and Reporting.

Specific Authority 403.061, 403.087 FS. Law Implemented 403.031, 403.061, 403.087 FS. History – New ________.

62-296.470 Implementation of Federal Clean Air Interstate Rule.

(1) through (2) No change.

(3) CAIR NOx Annual Trading Program. Except as otherwise provided herein, all provisions of the following subparts of 40 CFR Part 96 shall apply verbatim. The provisions of Subpart II, CAIR NOx Opt-In Units, shall not apply.

(a) through (c) No change.

(d) Subpart EE, CAIR NOx Allowance Allocations, provided that substitute language, as set forth below, shall apply in lieu of the indicated provisions ~~(Reserved)~~.

1. In lieu of the language at 40 CFR 96.141(a), substitute:

"By October 31, 2006, the permitting authority will submit to the Administrator the CAIR NOx allowance allocations, in a format prescribed by the Administrator and in accordance with sections 96.142(a) and (b), for the control periods in 2009, 2010, 2011, and 2012."

2. In lieu of the language at 40 CFR 96.141(b), substitute:

"By October 31, 2009, and October 31 of each third year thereafter, the permitting authority will submit to the Administrator the CAIR NOx allowance allocations, in a format prescribed by the Administrator and in accordance with sections 96.142(a) and (b), for the control periods in the fourth, fifth, and sixth years after the year of the applicable deadline for submission under this paragraph."

3. In lieu of the language at 40 CFR 96.142(a)(1), substitute:

"The baseline heat input (in mmBtu) used with respect to CAIR NOx allowance allocations under paragraph (b) of this section for each CAIR NOx unit will be:

(i) For units commencing operation before January 1, 2000: the average of the 3 highest amounts of the unit's adjusted control period heat input for 2000 through 2004; for units commencing operation on or after January 1, 2000, and before January 1, 2007: the average of the 3 highest amounts of the unit's adjusted control period heat input over the first 5 calendar years following the year in which the unit commenced operation, or the average of the 2 highest amounts of the unit's adjusted control period heat input over the first 4 calendar years following the year in which the unit commenced operation, or the maximum adjusted control period heat input over the first 1 to 3 calendar years following the year in which the unit commenced operation, depending on the maximum number (1 to 5) of such calendar years of data available to the permitting authority for determination of allowance allocations pursuant to sections 96.141(a) or 96.141(b); with the adjusted control period heat input for each year calculated as follows:

(A) If the unit is 85 percent or more (on a Btu basis) biomass-fired during the year and is subject to best available control technology (BACT) for NOx emissions, the unit's control period heat input for such year is multiplied by 150 percent;

(B) If the unit is coal-fired during the year, and not subject to paragraph (a)(1)(i)(A) of this section for the year, the unit's control period heat input for such year is multiplied by 100 percent;

(C) 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

(D) If the unit is not subject to paragraph (a)(1)(i)(A), (B), or (C) 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, 2007: the average of the 3 highest amounts of the unit's total converted control period heat input over the first 5 calendar years following the year in which the unit commenced operation, or the average of the 2 highest amounts of the unit's total converted control period heat input over the first 4 calendar years following the year in which the unit commenced operation, or the maximum total converted control period heat input over the first 1 to 3 calendar years following the year in which the unit commenced operation, depending on the maximum number (1 to 5) of such calendar years of data available to the permitting authority for determination of allowance allocations pursuant to section 96.141(b).

(iii) Notwithstanding paragraphs (a)(1)(i) and (ii) of this section, for any unit that is permanently retired and has not operated during the most recent five-year period for which the permitting authority has data upon which to base allocations: zero (0)."

4. In lieu of the language at 40 CFR 96.142(a)(2)(i), substitute:

"A unit's control period heat input, and a unit's status as biomass-fired, coal-fired or oil-fired, for a calendar year under paragraph (a)(1)(i) of this section, and a unit's total tons of NOx 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."

5. In lieu of the language at 40 CFR 96.142(a)(2)(ii)(A), substitute:

"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 biomass-fired (85 percent or more on a Btu basis) for the year, 7,900 Btu/kWh if the unit is coal-fired for the year, or 6,675 Btu/kWh if the unit is not biomass-fired or 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;"

6. In lieu of the language at 40 CFR 96.142(b)(1), substitute:

"For each control period in 2009 and thereafter, the permitting authority will allocate to all CAIR NOx units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of CAIR NOx allowances equal to 95 percent of the tons of NOx emissions in the State trading budget under section 96.140 (except as provided in paragraph (d) of this section)."

7. In lieu of the language at 40 CFR 96.142(c)(1), substitute:

"The permitting authority will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated CAIR NOx allowances equal to 5 percent of the amount of tons of NOx emissions in the State tradin budget under section 96.140, adjusted as necessary to ensure that the sum of all allocations made by the permitting authority does not exceed the State trading budget."

8. In lieu of the language at 40 CFR 96.142(c)(4)(iv), substitute:

"If the amount of CAIR NOx 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 NOx unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the CAIR NOx allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of CAIR NOx 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 using such rounding convention that results in allocation of the precise number of allowances in the new unit set-aside."

9. In lieu of the language at 40 CFR 96.142(d), substitute:

"If, after completion of the procedures under paragraph (c)(4) of this section for a control period, any unallocated CAIR NOx allowances remain in the new unit set-aside for the control period, the permitting authority will allocate to each CAIR NOx unit that was allocated CAIR NOx allowances under paragraph (b) of this section an amount of CAIR NOx allowances equal to the total amount of such remaining unallocated CAIR NOx allowances, multiplied by the unit's allocation under paragraph (b) of this section, divided by 95 percent of the amount of tons of NOx emissions in the State trading budget under section 96.140, and rounded to the nearest whole allowance using such rounding convention that results in allocation of the precise number of allowances remaining in the new unit set-aside."

10. In lieu of the language at 40 CFR 96.143(a), substitute:

"The permitting authority will establish a separate compliance supplement pool for the control period in 2009 and will allocate CAIR NOx allowances equal to 8,335 tons to such pool. These allowances are in addition to the CAIR NOx allowances allocated under section 96.142."

11. In lieu of the language at 40 CFR 96.143(b), substitute:

"For any CAIR NOx unit in the State, if the unit's average annual NOx emission rate for 2007 or 2008 is less than 0.25 lb/mmBtu and, where such unit is included in a NOx averaging plan under section 76.11 of the chapter under the Acid Rain Program for such year, the unit's NOx averaging plan has an actual weighted average NOx emission rate for such year equal to or less than the actual weighted average NOx emission rate for the year before such year and if the unit achieves NOx emission reductions in 2007 and 2008, the CAIR designated representative of the unit may request early reduction credits, and allocation of CAIR NOx allowances from the compliance supplement pool under paragraph (a) of this section for such early reduction credits, in accordance with the following:"

12. In lieu of the language at 40 CFR 96.143(b)(2), substitute:

"The CAIR designated representative of such CAIR NOx unit shall submit to the permitting authority by May 1, 2009, a request, in a format specified by the permitting authority, for allocation of an amount of CAIR NOx allowances from the compliance supplement pool not exceeding the sum of the unit's heat input for the control period in 2007 multiplied by the difference (if any greater than zero) between 0.25 lb/mmBtu and the unit's NOx emission rate for the control period in 2007 plus the unit's heat input for the control period in 2008 multiplied by the difference (if any greater than zero) between 0.25 lb/mmBtu and the unit's NOx emission rate for the control period in 2008, determined in accordance with subpart HH of this part and with the sum divided by 2,000 lb/ton and rounded to the nearest whole number of tons as appropriate."

(e) through (g) No change.

(4) No change.

(5) CAIR NOx Ozone Season Trading Program. Except as otherwise provided herein, all provisions of the following subparts of 40 CFR Part 96 shall apply verbatim. The provisions of Subpart IIII, CAIR NOx Ozone Season Opt-In Units, shall not apply.

(a) through (c) No change.

(d) Subpart EEEE, CAIR NOx Ozone Season Allowance Allocations, provided that substitute language, as set forth below, shall apply in lieu of the indicated provisions ~~(Reserved)~~.

1. In lieu of the language at 40 CFR 96.341(a), substitute:

"By October 31, 2006, the permitting authority will submit to the Administrator the CAIR NOx Ozone Season allowance allocations, in a format prescribed by the Administrator and in accordance with sections 96.342(a) and (b), for the control periods in 2009, 2010, 2011, and 2012."

2. In lieu of the language at 40 CFR 96.341(b), substitute:

"By October 31, 2009, and October 31 of each third year thereafter, the permitting authority will submit to the Administrator the CAIR NOx Ozone Season allowance allocations, in a format prescribed by the Administrator and in accordance with sections 96.342(a) and (b), for the control periods in the fourth, fifth, and sixth years after the year of the applicable deadline for submission under this paragraph."

3. In lieu of the language at 40 CFR 96.342(a)(1), substitute:

"The baseline heat input (in mmBtu) used with respect to CAIR NOx Ozone Season allowance allocations under paragraph (b) of this section for each CAIR NOx Ozone Season unit will be:

(i) For units commencing operation before January 1, 2000: the average of the 3 highest amounts of the unit's adjusted control period heat input for 2000 through 2004; for units commencing operation on or after

January 1, 2000, and before January 1, 2007: the average of the 3 highest amounts of the unit's adjusted control period heat input over the first 5 calendar years following the year in which the unit commenced operation, or the average of the 2 highest amounts of the unit's adjusted control period heat input over the first 4 calendar years following the year in which the unit commenced operation, or the maximum adjusted control period heat input over the first 1 to 3 calendar years following the year in which the unit commenced operation, depending on the maximum number (1 to 5) of such calendar years of data available to the permitting authority for determination of allowance allocations pursuant to sections 96.341(a) or 96.341(b); with the adjusted control period heat input for each year calculated as follows:

(A) If the unit is 85 percent or more (on a Btu basis) biomass-fired during the year and is subject to best available control technology (BACT) for NOx emissions, the unit's control period heat input for such year is multiplied by 150 percent;

(B) If the unit is coal-fired during the year, and not subject to paragraph (a)(1)(i)(A) of this section for the year, the unit's control period heat input for such year is multiplied by 100 percent;

(C) 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

(D) If the unit is not subject to paragraph (a)(1)(i)(A), (B), or (C) 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, 2007: the average of the 3 highest amounts of the unit's total converted control period heat input over the first 5 calendar years following the year in which the unit commenced operation, or the average of the 2 highest amounts of the unit's total converted control period heat input over the first 4 calendar years following the year in which the unit commenced operation, or the maximum total converted control period heat input over the first 1 to 3 calendar years following the year in which the unit commenced operation, depending on the maximum number (1 to 5) of such calendar years of data available to the permitting authority for determination of allowance allocations pursuant to section 96.341(b).

(iii) Notwithstanding paragraphs (a)(1)(i) and (ii) of this section, for any unit that is permanently retired and has not operated during the most recent five-year period for which the permitting authority has data upon which to base allocations: zero (0)."

4. In lieu of the language at 40 CFR 96.342(a)(2)(i), substitute:

"A unit's control period heat input, and a unit's status as biomass-fired, coal-fired or oil-fired, for a calendar year under paragraph (a)(1)(i) of this section, and a unit's total tons of NOx emissions during a control period in 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."

5. In lieu of the language at 40 CFR 96.342(a)(2)(ii)(A), substitute:

"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 biomass-fired (85 percent or more on a Btu basis) for the year, 7,900 Btu/kWh if the unit is coal-fired for the year, or 6,675 Btu/kWh if the unit is not biomass-fired or 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;"

6. In lieu of the language at 40 CFR 96.342(b)(1), substitute:

"For each control period in 2009 and thereafter, the permitting authority will allocate to all CAIR NOx 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 NOx allowances equal to 95 percent of the tons of NOx emissions in the State trading budget under section 96.340 (except as provided in paragraph (d) of this section)."

7. In lieu of the language at 40 CFR 96.342(c)(1), substitute:

"The permitting authority will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated CAIR NOx Ozone Season allowances equal to 5 percent of the amount of tons of NOx emissions in the State trading budget under section 96.340, adjusted as necessary to ensure that the sum of all allocations made by the permitting authority does not exceed the State trading budget."

8. In lieu of the language at 40 CFR 96.342(c)(4)(iv), substitute:

"If the amount of CAIR NOx 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 NOx Ozone Season unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the CAIR NOx Ozone Season allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of CAIR NOx 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 using such rounding convention that results in allocation of the precise number of allowances in the new unit set-aside."

9. In lieu of the language at 40 CFR 96.342(d), substitute:

"If, after completion of the procedures under paragraph (c)(4) of this section for a control period, any unallocated CAIR NOx Ozone Season allowances remain in the new unit set-aside for the control period, the permitting authority will allocate to each CAIR NOx Ozone Season unit that was allocated CAIR NOx Ozone Season allowances under paragraph (b) of this section an amount of CAIR NOx Ozone Season allowances equal to the total amount of such remaining unallocated CAIR NOx Ozone Season allowances, multiplied by the unit's allocation under paragraph (b) of this section, divided by 95 percent of the amount of tons of NOx emissions in the State trading budget under section 96.340, and rounded to the nearest whole allowance using such rounding convention that results in allocation of the precise number of allowances remaining in the new unit set-aside."

(e) through (g) No change.

Specific Authority 403.061, 403.087 FS. Law Implemented 403.031, 403.061, 403.087 FS. History – New 9-4-06, Amended ______.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
**************DRAFT**************

In Re: **In the Matter of Nitrogen Oxides (NOx) Annual and Ozone Season Allowance Allocations for Calendar Years 2009, 2010, 2011, and 2012 Pursuant to Implementation of the Federal Clean Air Interstate Rule (CAIR)**

ORDER ALLOCATING CAIR NOx ALLOWANCES AND CAIR NOx OZONE SEASON ALLOWANCES PURSUANT TO FLORIDA ADMINISTRATIVE CODE RULE 62-296.470 AND TITLE 40, CODE OF FEDERAL REGULATIONS, PART 96, SUBPARTS EE AND EEEE, FOR CALENDAR YEARS 2009, 2010, 2011, AND 2012

The Department of Environmental Protection (Department) takes agency action to allocate CAIR NOx allowances and CAIR NOx ozone season allowances, in tons per year, for calendar years 2009, 2010, 2011, and 2012 to CAIR Units (CAIR NOx units and CAIR NOx Ozone Season units) as set forth in Exhibit A.

The Department's proposed agency action shall become final unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, Florida Statutes (F.S.), before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed agency action may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida, 32399-3000.

Petitions filed by the owners or operators of CAIR Units must be filed within twenty-one days of receipt of this notice of intent. Petitions filed by other persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within twenty-one days of publication of the public notice or within twenty-one days of receipt of this notice, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within twenty-one days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the owners or operators of CAIR Units at the addresses indicated below (Exhibit B attached) at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the discretion of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information:

(a) The name and address of the Department and the Department's file or identification number, if known.
(b) The name, address, and telephone number of the petitioner; the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding;
(c) A statement of when and how petitioner received notice of the agency action or proposed action;
(d) An explanation of how the petitioner's substantial interests will be affected by the agency action or proposed action;
(e) A statement of all disputed issues of material facts. If there are none, the petition must so indicate;
(f) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action;
(g) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action, including an explanation of how the alleged facts relate to the specific rules or statutes; and
(h) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts on which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the Position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available in this proceeding.

NOTICE OF APPEAL RIGHTS

Any party to this order has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

DONE AND ORDERED this ______ day of ________________, 2007 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

JOSEPH KAHN, Director
Division of Air Resource Management
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 488-0114

FILING AND ACKNOWLEDGMENT

FILED, on this date, pursuant to §120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged. All copies were mailed before the close of business on the date below to the persons listed.

______________________ ________________
Clerk (or Deputy Clerk) Date

Copies furnished to the persons listed at Exhibit B.

Exhibit A

CAIR NOx Annual & CAIR NOx Ozone Season Allowance Allocations

************DRAFT************

Owner/Company Name	Facility Name (CAIR Source)	Federal Facility ID	ARMS Facility ID	CAIR Unit Federal Unit ID	CAIR Unit ARMS Unit ID	NOx Allowance per Year: 2009 - 2012 Annual (tons)	NOx Allowance per Year: 2009 - 2012 Ozone Season (tons)
Calpine Corporation	Santa Rosa Energy	55242	1130168	380	1	28	29
Calpine/Auburndale Power Partners, LP	Auburndale	54658	1050221	CT, ST	1	233	102
Calpine/Auburndale Power Partners, LP	Auburndale	54658	1050221		6	11	8
Cedar Bay Cogeneration, Inc.	Cedar Bay Generating Co.	10672	0310337	GEN1	1	518	243
Cedar Bay Cogeneration, Inc.	Cedar Bay Generating Co.	10672	0310337	GEN1	2	495	234
Cedar Bay Cogeneration, Inc.	Cedar Bay Generating Co.	10672	0310337	GEN1	3	502	241
City of Lake Worth Utilities	Tom G. Smith	673	0990045	GT1	6	2	1
City of Lake Worth Utilities	Tom G. Smith	673	0990045	S-3	9	18	8
City of Lake Worth Utilities	Tom G. Smith	673	0990045		10	0	0
City of Tallahassee	Arvah B. Hopkins	688	0730003	1	1	71	33
City of Tallahassee	Arvah B. Hopkins	688	0730003	CT2	3	4	3
City of Tallahassee	Arvah B. Hopkins	688	0730003	2	4	294	156
City of Tallahassee	Sam O. Purdom	689	1290001	7	7	22	13
City of Tallahassee	Sam O. Purdom	689	1290001	8	14	325	147
City of Vero Beach	Vero Beach Municipal	693	0610029	3	3	6	4
City of Vero Beach	Vero Beach Municipal	693	0610029	4	4	22	15
City of Vero Beach	Vero Beach Municipal	693	0610029	**5	5	33	21
Desoto County Generating Co., LLC	Desoto County Plant	55422	0270016	CT1	1	74	53
Desoto County Generating Co., LLC	Desoto County Plant	55422	0270016	CT2	2	85	53
Florida Crushed Stone Co., Inc.	Central Power And Lime, Inc.	10333	0530021	GEN1	18	702	321
Florida Power & Light	Cape Canaveral	609	0090006	PCC1	1	714	370
Florida Power & Light	Cape Canaveral	609	0090006	PCC2	2	692	361
Florida Power & Light	Cutler	610	0250001	PCU5	3	37	31
Florida Power & Light	Cutler	610	0250001	PCU6	4	80	62
Florida Power & Light	Fort Myers	612	0710002	PFM1	1	114	70
Florida Power & Light	Fort Myers	612	0710002	PFM2	2	470	245
Florida Power & Light	Fort Myers	612	0710002	GT1	3	5	4
Florida Power & Light	Fort Myers	612	0710002	GT2	4	5	4
Florida Power & Light	Fort Myers	612	0710002	3	5	5	4
Florida Power & Light	Fort Myers	612	0710002	4	6	5	4
Florida Power & Light	Fort Myers	612	0710002	5	7	5	4
Florida Power & Light	Fort Myers	612	0710002	6	8	5	4
Florida Power & Light	Fort Myers	612	0710002	7	9	5	4
Florida Power & Light	Fort Myers	612	0710002	8	10	5	4
Florida Power & Light	Fort Myers	612	0710002	9	11	5	4
Florida Power & Light	Fort Myers	612	0710002	G10	12	5	4
Florida Power & Light	Fort Myers	612	0710002	11	13	5	4
Florida Power & Light	Fort Myers	612	0710002	12	14	5	4
Florida Power & Light	Fort Myers	612	0710002	FMCT2A	18	309	140
Florida Power & Light	Fort Myers	612	0710002	FMCT2B	19	305	139
Florida Power & Light	Fort Myers	612	0710002	FMCT2C	20	311	144
Florida Power & Light	Fort Myers	612	0710002	FMCT2D	21	327	145
Florida Power & Light	Fort Myers	612	0710002	FMCT2E	22	327	145
Florida Power & Light	Fort Myers	612	0710002	FMCT2F	23	322	140
Florida Power & Light	Fort Myers	612	0710002	FMCT3A	27	68	51
Florida Power & Light	Fort Myers	612	0710002	FMCT3B	28	81	59
Florida Power & Light	Lauderdale	613	0110037	1	3	4	3
Florida Power & Light	Lauderdale	613	0110037	2	3	4	3
Florida Power & Light	Lauderdale	613	0110037	3	3	4	3
Florida Power & Light	Lauderdale	613	0110037	4	3	4	3
Florida Power & Light	Lauderdale	613	0110037	5	3	4	3
Florida Power & Light	Lauderdale	613	0110037	6	3	4	3
Florida Power & Light	Lauderdale	613	0110037	7	3	4	3
Florida Power & Light	Lauderdale	613	0110037	8	3	4	3
Florida Power & Light	Lauderdale	613	0110037	9	3	4	3
Florida Power & Light	Lauderdale	613	0110037	10	3	4	3
Florida Power & Light	Lauderdale	613	0110037	11	3	4	3
Florida Power & Light	Lauderdale	613	0110037	12	3	4	3

Owner/Company Name	Facility Name (CAIR Source)	Federal Facility ID	ARMS Facility ID	CAIR Unit		NOx Allowance per Year: 2009 - 2012	
				Federal Unit ID	ARMS Unit ID	Annual (tons)	Ozone Season (tons)
Florida Power & Light	Lauderdale	613	0110037	13	15	4	2
Florida Power & Light	Lauderdale	613	0110037	14	15	4	2
Florida Power & Light	Lauderdale	613	0110037	15	15	4	2
Florida Power & Light	Lauderdale	613	0110037	16	15	4	2
Florida Power & Light	Lauderdale	613	0110037	17	15	4	2
Florida Power & Light	Lauderdale	613	0110037	18	15	4	2
Florida Power & Light	Lauderdale	613	0110037	19	15	4	2
Florida Power & Light	Lauderdale	613	0110037	20	15	4	2
Florida Power & Light	Lauderdale	613	0110037	21	15	4	2
Florida Power & Light	Lauderdale	613	0110037	22	15	4	2
Florida Power & Light	Lauderdale	613	0110037	23	15	4	2
Florida Power & Light	Lauderdale	613	0110037	24	15	4	2
Florida Power & Light	Lauderdale	613	0110037	4GT1	35	323	148
Florida Power & Light	Lauderdale	613	0110037	4GT2	36	323	146
Florida Power & Light	Lauderdale	613	0110037	5GT1	37	330	147
Florida Power & Light	Lauderdale	613	0110037	5GT2	38	316	142
Florida Power & Light	Port Everglades	617	0110036	PPE1	1	285	185
Florida Power & Light	Port Everglades	617	0110036	PPE2	2	319	188
Florida Power & Light	Port Everglades	617	0110036	PPE3	3	690	353
Florida Power & Light	Port Everglades	617	0110036	PPE4	4	699	368
Florida Power & Light	Port Everglades	617	0110036	GT1	5	3	2
Florida Power & Light	Port Everglades	617	0110036	GT2	6	3	2
Florida Power & Light	Port Everglades	617	0110036	GT3	7	3	2
Florida Power & Light	Port Everglades	617	0110036	GT4	8	3	2
Florida Power & Light	Port Everglades	617	0110036	GT5	9	3	2
Florida Power & Light	Port Everglades	617	0110036	6	10	3	2
Florida Power & Light	Port Everglades	617	0110036	7	11	3	2
Florida Power & Light	Port Everglades	617	0110036	8	12	3	2
Florida Power & Light	Port Everglades	617	0110036	9	13	3	2
Florida Power & Light	Port Everglades	617	0110036	10	14	3	2
Florida Power & Light	Port Everglades	617	0110036	11	15	3	2
Florida Power & Light	Port Everglades	617	0110036	12	16	3	2
Florida Power & Light	Riviera	619	0990042	PRV3	3	522	270
Florida Power & Light	Riviera	619	0990042	PRV4	4	559	274
Florida Power & Light	Sanford	620	1270009	PSN3	1	167	101
Florida Power & Light	Sanford	620	1270009	PSN4	2	538	287
Florida Power & Light	Sanford	620	1270009	PSN5	3	385	209
Florida Power & Light	Sanford	620	1270009	SNCT4A	5	327	145
Florida Power & Light	Sanford	620	1270009	SNCT4B	6	327	148
Florida Power & Light	Sanford	620	1270009	SNCT4C	7	333	147
Florida Power & Light	Sanford	620	1270009	SNCT4D	8	338	143
Florida Power & Light	Sanford	620	1270009	SNCT5A	9	321	144
Florida Power & Light	Sanford	620	1270009	SNCT5B	10	326	145
Florida Power & Light	Sanford	620	1270009	SNCT5C	11	335	147
Florida Power & Light	Sanford	620	1270009	SNCT5D	12	312	137
Florida Power & Light	Turkey Point	621	0250003	PTP1	1	644	351
Florida Power & Light	Turkey Point	621	0250003	PTP2	2	660	347
Florida Power & Light	Manatee	6042	0810010	PMT1	1	1,271	626
Florida Power & Light	Manatee	6042	0810010	PMT2	2	1,313	682
Florida Power & Light	Martin	6043	0850001	PMR1	1	1,234	699
Florida Power & Light	Martin	6043	0850001	PMR2	2	1,298	652
Florida Power & Light	Martin	6043	0850001	HRSG3A, 3ST	3	331	145
Florida Power & Light	Martin	6043	0850001	HRSG3B, 3ST	4	347	146
Florida Power & Light	Martin	6043	0850001	HRSG4A, 4ST	5	338	154
Florida Power & Light	Martin	6043	0850001	HRSG4B, 4ST	6	337	152
Florida Power & Light	Martin	6043	0850001	PMR8A	11	76	48
Florida Power & Light	Martin	6043	0850001	PMR8B	12	114	76

Owner/Company Name	Facility Name (CAIR Source)	Federal Facility ID	ARMS Facility ID	CAIR Unit		NOx Allowance per Year: 2009 - 2012	
				Federal Unit ID	ARMS Unit ID	Annual (tons)	Ozone Season (tons)
Florida Power & Light	Putnam	6246	1070014	1GT1/ HRSG11	3,7	140	69
Florida Power & Light	Putnam	6246	1070014	1GT2/ HRSG12	4,8	139	68
Florida Power & Light	Putnam	6246	1070014	2GT1/ HRSG21	5,9	132	65
Florida Power & Light	Putnam	6246	1070014	2GT2/ HRSG22	6,10	133	66
Ft. Pierce Utilities Authority	H.D. King	658	1110003	7	7	7	4
Ft. Pierce Utilities Authority	H.D. King	658	1110003	8	8	12	9
Gainesville Regional Utilities	Deerhaven	663	0010006	B1	3	106	57
Gainesville Regional Utilities	Deerhaven	663	0010006	B2	5	1,040	508
Gainesville Regional Utilities	Deerhaven	663	0010006	CT3	6	24	16
Gainesville Regional Utilities	J. R. Kelly	664	0010005	JRK8	8	7	6
Gainesville Regional Utilities	J. R. Kelly	664	0010005	CC1	10	81	37
Gulf Power Company	Crist	641	0330045	1	1	8	7
Gulf Power Company	Crist	641	0330045	2	2	8	7
Gulf Power Company	Crist	641	0330045	3	3	14	11
Gulf Power Company	Crist	641	0330045	4	4	369	172
Gulf Power Company	Crist	641	0330045	5	5	406	182
Gulf Power Company	Crist	641	0330045	6	6	1,224	570
Gulf Power Company	Crist	641	0330045	7	7	2,319	1,136
Gulf Power Company	Scholz	642	0630014	1	1	156	76
Gulf Power Company	Scholz	642	0630014	2	2	181	84
Gulf Power Company	Lansing Smith	643	0050014	1	1	830	378
Gulf Power Company	Lansing Smith	643	0050014	2	2	964	433
Gulf Power Company	Lansing Smith	643	0050014	4	4	233	122
Gulf Power Company	Lansing Smith	643	0050014	5	5	230	122
Hardee Power Partners	Hardee Power Station	50949	0490015	CT1A	1	121	58
Hardee Power Partners	Hardee Power Station	50949	0490015	CT1B	2	121	59
Hardee Power Partners	Hardee Power Station	50949	0490015	CT2A	3	45	25
Hardee Power Partners	Hardee Power Station	50949	0490015	CT2B	5	31	16
Indiantown Cogeneration, LP	Indiantown Cogeneration Facility	50976	0850102	GEN1	1	1,562	709
JEA	St Johns River Power Park	207	0310045	1	16	3,676	1,630
JEA	St Johns River Power Park	207	0310045	2	17	3,453	1,490
JEA	Kennedy	666	0310047	GT3	3	7	4
JEA	Kennedy	666	0310047	GT4	4	8	4
JEA	Kennedy	666	0310047	GT5	5	7	3
JEA	Kennedy	666	0310047	10	9	2	0
JEA	Kennedy	666	0310047	GT37	15	73	49
JEA	Northside	667	0310045	1	1	272	152
JEA	Northside	667	0310045	3	3	849	463
JEA	Northside	667	0310045	GT3	6	9	5
JEA	Northside	667	0310045	4	7	7	3
JEA	Northside	667	0310045	5	8	7	3
JEA	Northside	667	0310045	6	9	8	5
JEA	Northside	667	0310045	2A	26	1,161	546
JEA	Northside	667	0310045	1A	27	1,198	509
JEA	Southside	668	0310046	4	4	58	39
JEA	Southside	668	0310046	5	5	99	51
JEA	Brandy Branch	7846	0310485	1	1	106	54
JEA	Brandy Branch	7846	0310485	2	2	98	53
JEA	Brandy Branch	7846	0310485	3	3	97	51
Kissimmee Utility Authority	Hansel	672	0970001	21,22,23	1	25	12
Kissimmee Utility Authority	Cane Island	7238	0970043	1	1	9	6
Kissimmee Utility Authority	Cane Island	7238	0970043	2, 2A	2	148	78
Kissimmee Utility Authority	Cane Island	7238	0970043	134, 135	3	277	137
Lake Investment, LP	Lake Cogeneration	54423	0694801	GT1, ST1	3	72	30
Lake Investment, LP	Lake Cogeneration	54423	0694801	GT2, ST1	4	74	32
Lakeland Electric	Larsen Memorial	675	1050003	7	4	39	23
Lakeland Electric	Larsen Memorial	675	1050003	**8	8	91	49
Lakeland Electric	C.D. Mclintosh Jr.	676	1050004	1	1	122	73
Lakeland Electric	C.D. Mclintosh Jr.	676	1050004	2	5	116	63
Lakeland Electric	C.D. Mclintosh Jr.	676	1050004	3	6	1,961	904
Lakeland Electric	C.D. Mclintosh Jr.	676	1050004	5CT, 289	28	291	171

Owner/Company Name	Facility Name (CAIR Source)	Federal Facility ID	ARMS Facility ID	CAIR Unit		NOx Allowance per Year: 2009 - 2012	
				Federal Unit ID	ARMS Unit ID	Annual (tons)	Ozone Season (tons)
New Hope Power Partnership	Okeelanta Cogeneration	54627	0990332	GEN1	1	404	145
New Hope Power Partnership	Okeelanta Cogeneration	54627	0990332	GEN1	2	394	142
New Hope Power Partnership	Okeelanta Cogeneration	54627	0990332	GEN1	3	414	159
Oleander Power Project, LP	Oleander Power	55286	0090180	314	1	107	30
Oleander Power Project, LP	Oleander Power	55286	0090180	315	2	66	19
Oleander Power Project, LP	Oleander Power	55286	0090180	316	3	63	14
Oleander Power Project, LP	Oleander Power	55286	0090180	317	4	59	26
Orange Cogeneration, LP	Orange Cogeneration	54365	1050231	1	1	47	21
Orange Cogeneration, LP	Orange Cogeneration	54365	1050231	2	2	47	20
Orlando Cogen Limited, LP	Orlando Cogen	54466	0950203	GEN1	1,2	196	85
Orlando Utilities Commission	Stanton Energy Center	564	0950137	1	1	2,159	1,007
Orlando Utilities Commission	Stanton Energy Center	564	0950137	2	2	2,139	1,009
Orlando Utilities Commission	Stanton Energy Center	564	0950137		25	277	143
Orlando Utilities Commission	Stanton Energy Center	564	0950137		26	274	140
Orlando Utilities Commission	OUC Indian River	683	0090008	A	4	3	2
Orlando Utilities Commission	OUC Indian River	683	0090008	**C	5	14	9
Orlando Utilities Commission	OUC Indian River	683	0090008	**D	6	16	10
Orlando Utilities Commission	OUC Indian River	683	0090008	B	7	3	2
Pasco Cogen Limited	Pasco Cogeneration	54424	1010071	GT1/ST1	1	69	29
Pasco Cogen Limited	Pasco Cogeneration	54424	1010071	GT2/ST1	2	70	28
Polk Power Partners, LP	Mulberry Cogen	54426	1050217	GT1/ST1	1	97	40
Progress Energy Florida, Inc.	Avon Park	624	0550003	P1	3	9	7
Progress Energy Florida, Inc.	Avon Park	624	0550003	P2	4	4	3
Progress Energy Florida, Inc.	Bayboro	627	1030013	P1	1	13	9
Progress Energy Florida, Inc.	Bayboro	627	1030013	P2	2	12	9
Progress Energy Florida, Inc.	Bayboro	627	1030013	P3	3	16	12
Progress Energy Florida, Inc.	Bayboro	627	1030013	P4	4	17	13
Progress Energy Florida, Inc.	Crystal River	628	0170004	1	1	1,571	705
Progress Energy Florida, Inc.	Crystal River	628	0170004	2	2	2,024	937
Progress Energy Florida, Inc.	Crystal River	628	0170004	5	3	3,526	1,560
Progress Energy Florida, Inc.	Crystal River	628	0170004	4	4	3,577	1,645
Progress Energy Florida, Inc.	G.E. Turner	629	1270020	P3	9	12	8
Progress Energy Florida, Inc.	G.E. Turner	629	1270020	P4	10	11	8
Progress Energy Florida, Inc.	Higgins	630	1030012		1	0	0
Progress Energy Florida, Inc.	Higgins	630	1030012		2	0	0
Progress Energy Florida, Inc.	Higgins	630	1030012		3	0	0
Progress Energy Florida, Inc.	Higgins	630	1030012	P1	4	6	5
Progress Energy Florida, Inc.	Higgins	630	1030012	P2	5	5	4
Progress Energy Florida, Inc.	Higgins	630	1030012	P3	6	12	8
Progress Energy Florida, Inc.	Higgins	630	1030012	P4	7	12	8
Progress Energy Florida, Inc.	Bartow	634	1030011	1	1	282	143
Progress Energy Florida, Inc.	Bartow	634	1030011	2	2	286	148
Progress Energy Florida, Inc.	Bartow	634	1030011	3	3	510	265
Progress Energy Florida, Inc.	Bartow	634	1030011	P1	5	8	5
Progress Energy Florida, Inc.	Bartow	634	1030011	P2	6	17	12
Progress Energy Florida, Inc.	Bartow	634	1030011	P3	7	8	5
Progress Energy Florida, Inc.	Bartow	634	1030011	P4	8	14	10
Progress Energy Florida, Inc.	Suwannee River	638	1210003	1	1	62	47
Progress Energy Florida, Inc.	Suwannee River	638	1210003	2	2	61	45
Progress Energy Florida, Inc.	Suwannee River	638	1210003	3	3	98	74
Progress Energy Florida, Inc.	Suwannee River	638	1210003	P1	4	19	14
Progress Energy Florida, Inc.	Suwannee River	638	1210003	P2	5	14	10
Progress Energy Florida, Inc.	Suwannee River	638	1210003	P3	6	23	18
Progress Energy Florida, Inc.	Debary	6046	1270028	P1	3	11	7
Progress Energy Florida, Inc.	Debary	6046	1270028	2	5	9	6
Progress Energy Florida, Inc.	Debary	6046	1270028	3	7	10	7
Progress Energy Florida, Inc.	Debary	6046	1270028	4	9	10	7
Progress Energy Florida, Inc.	Debary	6046	1270028	5	11	10	7
Progress Energy Florida, Inc.	Debary	6046	1270028	6	13	8	6
Progress Energy Florida, Inc.	Debary	6046	1270028	**7	15	52	33
Progress Energy Florida, Inc.	Debary	6046	1270028	**8	16	55	34
Progress Energy Florida, Inc.	Debary	6046	1270028	**9	17	58	37
Progress Energy Florida, Inc.	Debary	6046	1270028	**10	18	30	20

Owner/Company Name	Facility Name (CAIR Source)	Federal Facility ID	ARMS Facility ID	CAIR Unit		NOx Allowance per Year: 2009 - 2012	
				Federal Unit ID	ARMS Unit ID	Annual (tons)	Ozone Season (tons)
Progress Energy Florida, Inc.	Hines Energy Complex	7302	1050234	1A	1	276	132
Progress Energy Florida, Inc.	Hines Energy Complex	7302	1050234	1B	2	280	131
Progress Energy Florida, Inc.	Hines Energy Complex	7302	1050234	2A	14	229	140
Progress Energy Florida, Inc.	Hines Energy Complex	7302	1050234	2B	15	254	148
Progress Energy Florida, Inc.	Univ. of Florida	7345	0010001	P1	1,5	89	41
Progress Energy Florida, Inc.	Tiger Bay Cogen	7699	1050223	CT1/CW1	1	473	296
Progress Energy Florida, Inc.	Anclote	8048	1010017	1	1	1,056	561
Progress Energy Florida, Inc.	Anclote	8048	1010017	2	2	1,068	546
Progress Energy Florida, Inc.	Intercession City	8049	0970014	P1	1	6	4
Progress Energy Florida, Inc.	Intercession City	8049	0970014	P2	2	9	7
Progress Energy Florida, Inc.	Intercession City	8049	0970014	P3	3	8	6
Progress Energy Florida, Inc.	Intercession City	8049	0970014	P4	4	10	8
Progress Energy Florida, Inc.	Intercession City	8049	0970014	P5	5	10	7
Progress Energy Florida, Inc.	Intercession City	8049	0970014	P6	6	8	6
Progress Energy Florida, Inc.	Intercession City	8049	0970014	**7	7	37	23
Progress Energy Florida, Inc.	Intercession City	8049	0970014	**8	8	39	24
Progress Energy Florida, Inc.	Intercession City	8049	0970014	**9	9	33	23
Progress Energy Florida, Inc.	Intercession City	8049	0970014	**10	10	38	24
Progress Energy Florida, Inc.	Intercession City	8049	0970014	**11	11	36	14
Progress Energy Florida, Inc.	Intercession City	8049	0970014	**12	18	39	25
Progress Energy Florida, Inc.	Intercession City	8049	0970014	**13	19	44	29
Progress Energy Florida, Inc.	Intercession City	8049	0970014	**14	20	42	25
Reliant Energy Florida, LLC	REI Indian River	55318	0090196	1	1	60	43
Reliant Energy Florida, LLC	REI Indian River	55318	0090196	2	2	183	122
Reliant Energy Florida, LLC	REI Indian River	55318	0090196	3	3	318	203
Reliant Energy Florida, LLC	Osceola	55192	0970071	CTG1	1	74	44
Reliant Energy Florida, LLC	Osceola	55192	0970071	CTG2	2	68	43
Reliant Energy Florida, LLC	Osceola	55192	0970071	357	3	29	19
Seminole Electric Cooperative, Inc.	Seminole Generating Station	136	1070025	1	1	3,255	1,561
Seminole Electric Cooperative, Inc.	Seminole Generating Station	136	1070025	2	2	3,454	1,548
Seminole Electric Cooperative, Inc.	Payne Creek	7380	0490340	CT1A/ST1	1	245	124
Seminole Electric Cooperative, Inc.	Payne Creek	7380	0490340	CT1B/ST1	2	240	117
Shady Hills Power Company, LLC	Shady Hills Generation	55414	1010373	GT101	1	90	54
Shady Hills Power Company, LLC	Shady Hills Generation	55414	1010373	GT201	2	105	62
Shady Hills Power Company, LLC	Shady Hills Generation	55414	1010373	GT301	3	95	63
Tampa Electric Company	Big Bend Station	645	0570039	BB01	1	1,737	725
Tampa Electric Company	Big Bend Station	645	0570039	BB02	2	1,770	785
Tampa Electric Company	Big Bend Station	645	0570039	BB03	3	1,644	735
Tampa Electric Company	Big Bend Station	645	0570039	BB04	4	2,205	975
Tampa Electric Company	Big Bend Station	645	0570039	GT2	5	20	12
Tampa Electric Company	Big Bend Station	645	0570039	GT3	6	14	8
Tampa Electric Company	Gannon Station	646	0570040	GB01	1	429	205
Tampa Electric Company	Gannon Station	646	0570040	GB02	2	405	179
Tampa Electric Company	Gannon Station	646	0570040	GB03	3	545	265
Tampa Electric Company	Gannon Station	646	0570040	GB04	4	588	297
Tampa Electric Company	Gannon Station	646	0570040	GB05	5	692	370
Tampa Electric Company	Gannon Station	646	0570040	GB06	6	1,205	630
Tampa Electric Company	Hookers Point Station	647	0570038	HB01	1	2	2
Tampa Electric Company	Hookers Point Station	647	0570038	HB02	2	2	2
Tampa Electric Company	Hookers Point Station	647	0570038	HB03	3	6	5
Tampa Electric Company	Hookers Point Station	647	0570038	HB04	4	8	7
Tampa Electric Company	Hookers Point Station	647	0570038	HB05	5	13	10
Tampa Electric Company	Hookers Point Station	647	0570038	HB06	6	9	8
Tampa Electric Company	Polk Power Station	7242	1050233	1	1	847	370
Tampa Electric Company	Polk Power Station	7242	1050233	2	9	78	45
Tampa Electric Company	Polk Power Station	7242	1050233	3	10	71	56
Tampa Electric Company	Bayside Station	7873	0570040	CT1A	20	182	121
Tampa Electric Company	Bayside Station	7873	0570040	CT1B	21	190	112
Tampa Electric Company	Bayside Station	7873	0570040	CT1C	22	188	116
Tampa Electric Company	Bayside Station	7873	0570040	CT2A	23	186	98
Tampa Electric Company	Bayside Station	7873	0570040	CT2B	24	179	103
Tampa Electric Company	Bayside Station	7873	0570040	CT2C	25	185	93
Tampa Electric Company	Bayside Station	7873	0570040	CT2D	26	197	106

Owner/Company Name	Facility Name (CAIR Source)	Federal Facility ID	ARMS Facility ID	CAIR Unit		NOx Allowance per Year: 2009 - 2012	
				Federal Unit ID	ARMS Unit ID	Annual (tons)	Ozone Season (tons)
Vandolah Power Company, LLC	Vandolah Power Co.	55415	0490043	GT101	1	30	21
Vandolah Power Company, LLC	Vandolah Power Co.	55415	0490043	GT201	2	29	18
Vandolah Power Company, LLC	Vandolah Power Co.	55415	0490043	GT301	3	19	13
Vandolah Power Company, LLC	Vandolah Power Co.	55415	0490043	GT401	4	26	14
Walt Disney World Company	Walt Disney World Resort	7254	0950111	32432	88	53	28
Wheelabrator Ridge Energy, Inc.	Ridge Generating Station	54529	1050216		1	106	46
Total for CAIR Units						**94,455**	**45,519**
New Unit Set Aside						**4,990**	**2,393**
Grand Total						**99,445**	**47,912**

Mississippi's Adoption of CAIR

SECTION 14. PROVISIONS FOR THE CLEAN AIR INTERSTATE RULE

1. The provisions of this paragraph apply to Electric Generating Units subject to the Clean Air Interstate Rule (CAIR) as set forth in 40 CFR 51.123, 40 CFR 51.124, and 40 CFR 96.102 through 40 CFR 96.388 as amended and promulgated by the U.S. Environmental Protection Agency as of September 15, 2006. All such requirements are incorporated herein and adopted by reference by the Mississippi Commission on Environmental Quality as official regulations of the State of Mississippi and shall hereafter be enforceable as such except as follows:

(a) The term Apermitting authority@ shall mean the "Mississippi Environmental Quality Permit Board" except when used in the definitions of "Allocate or allocation" and "CAIR NO_X allowance" in 40 CFR 96.102, the definitions of "Allocate or allocation" and "CAIR SO2 allowance" in 40 CFR 96.202, and the definitions of "Allocate or allocation" and "CAIR NO_X Ozone Season allowance" in 40 CFR 96.302.

(b) Unit specific nitrogen oxides (NO_X) annual and ozone season allowances shall be established by the Commission in accordance with the procedures outlined in 40 CFR 96.142 and 40 CFR 96.342 and will be assigned to each unit by the dates specified in 40 CFR 96.141 and 40 CFR 96.341.

APPENDIX E

State of Florida and State of Mississippi CAMR Rules

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen Castille
Secretary

To: Chairman and Members
Environmental Regulation Commission

From: Mike Sole, Deputy Secretary *M W Sole*
Regulatory Programs and Energy

Date: June 21, 2006

Subject: June 29, 2006, Rule Adoption Hearing
Rulemaking to Implement the Federal Clean Air Mercury Rule (CAMR)
Amendments to Chapters 62-204, 62-210, and 62-296, F.A.C.,

Purpose

The purpose of this rulemaking is to implement the requirements of the federal Clean Air Mercury Rule as it applies to coal-fired electric power plants in Florida.

Section 111 of the federal Clean Air Act requires the United States Environmental Protection Agency (EPA) to adopt and periodically update technology-based emissions limiting standards for certain pollutants on an industry-specific basis. Under this section of the Act, EPA develops new source performance standards (NSPS) for new sources and, in some cases, "emission guidelines" for existing sources in the same industry category. The NSPS are EPA rules typically delegated to the states for enforcement. The "emission guidelines" must be adopted as state rules and submitted to EPA for approval. The state submittal is referred to as a "111(d) plan," after the paragraph of the Clean Air Act from which it derives.

On May 18, 2005, EPA promulgated the Clean Air Mercury Rule (CAMR), which includes NSPS and emission guidelines for mercury (Hg) emissions from coal-fired electric generating units (EGUs) nationwide. Each state must submit a 111(d) plan to EPA by November17, 2006, demonstrating that the state has adopted all necessary rules to implement the requirements of CAMR. Florida is subject to CAMR because the state has 32 coal-fired EGUs at 15 separate facilities.

The Department of Environmental Protection's (department) proposed amendments to Chapters 62-204, 62-210, and 62-296, Florida Administrative Code (F.A.C), are intended to satisfy the requirements of CAMR. If approved by the Environmental Regulation Commission (ERC), the department will submit the amendments to EPA for approval as Florida's required 111(d) plan for mercury. In addition to satisfying the public hearing requirements of section 120.54, Florida Statutes (F.S), the June 29, 2006, ERC rule

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adoption hearing is intended to satisfy the public hearing requirements of 40 CFR 60.23 for development of state 111(d) plans.

Summary

CAMR Compliance Options

CAMR establishes an annual Hg emissions budget or "cap" for each state to be implemented in two phases: 2010 through 2017, and 2018-on. The first phase Hg cap, 2,464 pounds per year for Florida, is designed to be achieved by taking advantage of "co-benefit" reductions; i.e., mercury reductions achieved by the control equipment installed to reduce sulfur dioxide (SO_2) and nitrogen oxides (NOx) emissions under the Clean Air Interstate Rule (CAIR). In the second phase, beginning in 2018, Florida's Hg cap declines to 974 pounds per year and becomes permanent thereafter. Mercury-specific emission control technologies may be needed to comply with the second-phase cap.

States may comply with the Hg emissions caps under CAMR by adopting unit-specific Hg emissions limiting standards or by opting-in to an EPA-administered national "cap-and-trade" program. The department considered the emission limiting standard approach for the first phase of CAMR, but through this rulemaking, is proposing that Florida opt-in to the national cap-and-trade program for both phases. The department's rulemaking proposal is structured such that the Hg reduction advantages of the emission limiting standard approach are still achieved, while the administrative and compliance flexibility advantages of the cap and trade program are also realized.

Mechanics of CAMR Cap-and-Trade Program

Under the Hg cap-and-trade program, EPA provides annual emissions allowances for Hg to each participating state in an amount equal to the state's cap for each year. The state, in turn, allocates all or part of those allowances to its coal-fired EGUs. The number of Hg allowances received by any EGU for a given year depends on the allocation system employed by the state. The Hg allowances allocated to EGUs by the state are deposited into a compliance account established by EPA for each affected unit. Each unit must ensure that at the end of each control year it holds enough eligible allowances in its compliance account to cover its Hg emissions for the year. EPA then deducts, or retires, from each unit's compliance account an amount of allowances equal to the unit's reported Hg emissions. A unit can only use allowances allocated for the control year or any previous year to satisfy its annual compliance requirement; it cannot use any future-year allowances it may hold.

Like the CAIR cap-and-trade programs, allowances may be traded with sources in other participating states or "banked" for future use. As a result, EGUs are able to choose from many compliance alternatives including installing pollution control equipment or buying excess allowances from other sources that have "over-controlled" their emissions. Because each unit must hold sufficient allowances to cover its Hg emissions each year, the limited number of allowances available ensures that emission reductions are achieved.

The mandatory emissions caps, along with stringent emissions monitoring and reporting requirements and significant EPA-imposed automatic penalties for noncompliance, ensure that human health and environmental goals are achieved and sustained.

Details of Opting-in to CAMR Cap-and-Trade Program

EPA has developed a "CAMR model rule" for the Hg cap-and-trade program. A state that opts-in to the national cap-and-trade program must adopt by reference or otherwise adhere to the model rule with only such limited modifications as are allowed by EPA. The only modifications allowed by EPA relate to the methodology for allocating Hg allowances to individual EGUs. While the CAMR model rule provides a suggested methodology, EPA allows each participating state to allocate Hg allowances to its EGUs in any manner of its choosing as long as the state cap is not exceeded and certain other conditions are met. The department has taken advantage of this flexibility to develop an allocation methodology that is similar to the model rule approach but includes certain changes to address Florida-specific issues and to effect a smoother administration of the program.

If the department's proposed allocation methodology is approved by the ERC through this rulemaking, the department will, as soon as possible thereafter, issue an administrative order setting forth the Hg allowances determined for each coal-fired EGU for control years 2010 through 2012 based on the adopted methodology. These allocations must be submitted to EPA by November 17, 2006, for recordation in the EPA compliance account of each affected EGU.

It should be noted that if a state fails to timely submit an approvable CAMR 111(d) plan, it will lose the flexibility to allocate Hg allowances as it sees fit. Instead, EPA has indicated its intention to impose the model rule methodology on such state by default and allocate allowances to the state's coal-fired EGUs accordingly. Given this reality, the department used the model rule as its starting point for developing Florida's proposed allocation methodology. In most respects, the department's proposed methodology for allocating Hg allowances under CAMR is the same as its proposed methodology for allocating NOx allowances under CAIR. The primary difference is the creation under CAMR of a "compliance set-aside," which will be discussed later in this memo.

<u>Statutory Authority</u>

Section 403.061(35), F.S., authorizes the department to "exercise the duties, powers, and responsibilities required of the state under the federal Clean Air Act." These duties and responsibilities include the development and periodic updating of 111(d) plans as required by EPA. The rule amendments to implement CAMR are being proposed pursuant to this specific statutory authority.

Department's Rule Development Process

The department's Division of Air Resource Management held two conceptual workshops (November 29, 2005, and March 2, 2006) and one rulemaking workshop (April 13, 2006) to present options for implementing CAMR in Florida and to provide opportunities for public comment. Following each workshop, comments received by the division were posted on its website for review by all participants in the rulemaking process and other interested parties. See: http://www.dep.state.fl.us/Air/rules/regulatory.htm.

Department's Concern

In the first conceptual workshop, the department raised a concern with the cap-and-trade approach. Florida's Phase 1 cap on Hg emissions under CAMR is 2,464 pounds per year; yet, by EPA's estimation, actual Hg emissions from Florida's coal-fired plants in 1999 were 1,923 pounds per year. Furthermore, actual Hg emissions are expected to decline significantly during Phase 1 of CAMR due to the co-benefits of CAIR. While the department is pleased that these reductions are expected to occur, the concern is that the Phase 1 cap is too high, thus permitting a large number of surplus allowances to be "banked" during the early years of the program and used to delay by several years the further Hg emission reductions designed to occur during Phase 2 of the program.

The following table shows the department-projected Hg emission reductions that Florida may realize through the co-benefits of CAIR. As can be seen from the table, the department is projecting a 46 percent reduction in Hg emissions during Phase 1 of the program as a result of the CAIR-related control equipment Florida's utilities have indicated they plan to install by 2010 or shortly thereafter. If, like CAIR, a 5 percent new-unit set aside is established and 95 percent of the Phase 1 cap (2,343 pounds per year) is allocated to the state's current coal-fired power plants, approximately 1,300 pounds per year of surplus Hg allowances could become available for banking during Phase 1 of the program. (Note: The projected 46 percent reduction is based on the emissions factors developed by EPA as part of its 1999 estimate. Actual reductions may vary.)

CAMR Statewide Annual Emission Caps and Projected Emission Reductions

	Current (1999) Coal-Fired Power Plant Emissions (pounds/year)	**CAMR Phase 1 Emission Cap (pounds/year)**	**DEP-Projected Phase 1 Emissions due to CAIR co-benefit (pounds/year)**	**CAMR Phase 2 Emission Cap (pounds/year)**	**DEP-Projected Phase 2 Emissions (pounds/year)**
Hg	**1,923**	*2010 - 2017* **2,464**	**1,033** *(46% reduction from 1999)*	*2018-on* **974**	**?**

Workshop Proposals

Initially, the department proposed that, instead of opting-in to the cap-and-trade program during Phase 1 of CAMR, all but the very smallest coal-fired EGUs be required to comply with NSPS-equivalent Hg emission limiting standards. These limits would likely be met as a co-benefit of the control equipment expected to be installed for CAIR and would result in total allowable Hg emissions from Florida's current coal-fired power plants of 1,761 pounds per year. Under this proposal, there would be no banking or trading of allowances during Phase 1. The department would opt-in to the EPA-administered Hg cap-and-trade program at the beginning of Phase 2 in 2018.

Subsequently, the department invited comment on an alternative proposal whereby, in lieu of adopting emission limiting standards, the state would opt-in to the EPA-administered Hg cap-and-trade program from the beginning, with the proviso that, for the Phase 1 control years 2010-2017, the department would allocate a reduced percentage of the state's 2,464-pound annual Hg budget to EGUs eligible to receive allowances. During those years, the department would establish, in a general account, a "compliance set-aside" equal to the unallocated percentage of the state's annual Hg cap. If a unit operated its control equipment at all times yet still exceeded its allowance for a given year, the department would transfer allowances from the compliance set-aside to the unit during the end-of-year true-up period in sufficient quantity to cover its shortfall (but not to exceed a total amount equal to what the unit would have received absent the compliance set-aside). Beginning with control year 2018, the compliance set-aside would be discontinued, and units would be allocated 95 percent of the state's 974-pound Hg budget. A 5 percent new-unit set-aside would be established for all control periods.

Rulemaking Proposal

Based on its consideration of these implementation options and comments received from the workshops, the department has determined that the Hg cap-and-trade program is the best option for Florida because it provides the state's coal-fired EGUs access to the national allowance market and the flexibilities it is expected to provide. To address the banking concern, the department is proposing to allocate only 70 percent of the CAMR Phase 1 allowances to existing EGUs and hold back 25 percent of the allowances for each year 2010 through 2017 in a compliance set-aside as described above. Allowances in the compliance set-aside would be made available during Phase 1 for distribution to those units that install control equipment but, for unforeseen reasons, fail to attain the degree of Hg emissions reduction expected as a co-benefit of those controls. The proposed 70 percent allocation equates to 1,725 pounds per year—roughly the same as the 1,761 pounds per year of total allowable emissions under the NSPS-equivalent approach. Attachment E to this memo lists the 2010-2012 Hg allocations that the department expects to make to individual facilities using the allocation methodology proposed in this rulemaking.

Also as described above, the department is proposing to establish a 5 percent new-unit set aside for both Phase 1 and Phase 2 of the program. Since it is possible that the new-unit set aside will be insufficient to cover all new units in some years, the department is further proposing to make unused Hg allowances in the compliance set-aside available to new units to cover any shortfall of new-unit set aside allowances that may arise in a given year. Allowances from the compliance set-aside pool would be available for this purpose in both Phase 1 and Phase 2 of the program, as long as such allowances remain available.

The rulemaking issues under CAIR that revolve around the treatment of natural gas-fired units versus coal-fired units do not arise under CAMR since only coal-fired units are affected. Therefore, the Florida Electric Power Coordinating Group (FCG) is able to present a consensus position to the department on its CAMR rulemaking proposal. The FCG supports the proposal to opt-in to the CAMR cap-and-trade program and is accepting of the compliance set-aside during Phase 1. *However, the FCG is recommending that the compliance set-aside be established beginning 2012, rather than 2010, to account for questions regarding the initial reliability and accuracy of continuous emissions monitors; difficulties in completing the installation of control equipment by 2010; and potential unavailability and cost of any needed allowances.*

As of the date of this memo, the department is considering the FCG recommendation and will be prepared to respond to it at the June 29, 2006, hearing.

<u>Proposed Rule Amendments</u>

The department is proposing amendments in three Florida Administrative Code rule chapters to implement the requirements of CAMR:

- Chapter 62-204, Air Pollution Control – General Requirements (OGC No. 06-0328)
- Chapter 62-210, Stationary Sources – General Requirements (OGC No. 06-0197)
- Chapter 62-296, Stationary Sources – Emission Standards (OGC No. 06-0198)

Brief summaries of the proposed amendments are provided below.

Rule 62-204.800, F.A.C., Federal Regulations Adopted by Reference

Rule 62-204.800, F.A.C, is amended to adopt and incorporate by reference the EPA CAMR model rule at 40 CFR Part 60, Subpart HHHH, and related EPA regulations at 40 CFR Part 75. As stated in the lead-in text of the rule, the purpose and effect of each federal regulation adopted by reference in this rule section is determined by the context in which it is cited. The new and amended federal regulations adopted by reference in Rule 62-204.800, F.A.C., as part of the CAMR rulemaking project are cited and given context in the department's related proposed amendments to Chapters 62-210 and 62-296, F.A.C. Any substantive modifications to the effects of such federal regulations are also set forth in the proposed amendments to Chapters 62-210 and 62-296, F.A.C.

An underlined, coded copy of the proposed amendments to Rule 62-204.800, F.A.C, can be found at Attachment A.

Rule 62-210.200, F.A.C., Definitions

Rule 62-210.200, F.A.C, is amended to add six new definitions and revise two existing definitions. Some of these definitions are used in Chapter 62-296, F.A.C., in provisions that are not part of the EPA CAMR regulation adopted by reference as part of this rulemaking project. Others are used in proposed CAMR-related amendments to the department's permitting rules for which a notice of proposed rulemaking has not yet been published. The permitting rule amendments will be proposed for Secretarial adoption following adoption of this set of rule amendments.

An underlined, coded copy of the proposed amendments to this rule section can be found at Attachment B.

Rule 62-296.800, F.A.C., Implementation of Federal Clean Air Mercury Rule

New Rule 62-296.480, F.A.C., is the heart of the department's overall rulemaking project related to CAMR implementation. In this rule section, the department sets forth its alternative methodology for distributing Hg allowance allocations to coal-fired EGUs. It does so by adopting "substitute language" to be used in applying the EPA CAMR model rule adopted and incorporated by reference at Rule 62-204.800, F.A.C. The substitute language modifies the EPA example allocation method as allowed pursuant to 40 CFR 60.24(h)(6)(ii) .

A state's methodology for allocating Hg allowances is approvable by EPA as long as the state allocates its allowances by certain prescribed dates and imposes no restrictions on their use for trading or banking within the EPA-administered system. EPA does not require the state to allocate a minimum number of allowances to any electric generating unit or to allocate allowances based on fuel usage, electrical output, or any other such system. Therefore, the department's proposed alternative allocation method is not more stringent than any federal standard.

An underlined, coded copy of the proposed amendments to this rule section can be found at Attachment C. A copy of the EPA Hg allowance allocation rule showing the DEP substitute language can be found at Attachment D.

Recommendation

The department recommends approval of the amendments to all three rule chapters as noticed on May 26, 2006.

Hg Allowance Allocations

§ 60.4140 State trading budgets.

The State trading budgets for annual allocations of Hg allowances for the control periods in 2010 through 2017 and in 2018 and thereafter are respectively as follows:

	State trading budget (tons)	
	2010-2017	2018 and thereafter
Florida	1.233	0.487

§ 60.4141 Timing requirements for Hg allowance allocations.

(a) By October 31, 2006, the permitting authority will submit to the Administrator the Hg allowance allocations, in a format prescribed by the Administrator and in accordance with sections 60.4142(a) and (b), for the control periods in 2010, 2011, and 2012.

(b)(1) By October 31, 2009, and October 31 of each third year thereafter, the permitting authority will submit to the Administrator the Hg allowance allocations, in a format prescribed by the Administrator and in accordance with sections 60.4142(a) and (b), for the control periods in the fourth, fifth, and sixth years after the year of the applicable deadline for submission under this paragraph.

(2) If the permitting authority fails to submit to the Administrator the Hg allowance allocations in accordance with paragraph (b)(1) of this section, the Administrator will assume that the allocations of Hg 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 2018, the Administrator will assume that the allocations equal the allocations for the control period in 2017, multiplied by the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the applicable State trading budget under §60.4140 for 2018 and thereafter and divided by such amount of ounces of Hg emissions for 2010 through 2017.

(c)(1) By October 31, 2010, and October 31 of each year thereafter, the permitting authority will submit to the Administrator the Hg allowance allocations, in a format prescribed by the Administrator and in accordance with sections 60.4142(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 Hg allowance allocations in accordance with paragraph (c)(1) of this section, the Administrator will assume that the allocations of Hg 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 2018, the Administrator will assume that the allocations equal the allocations for the control period in 2017, multiplied by the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the applicable State trading budget under § 60.4140 for 2018 and thereafter and divided by such amount of ounces of Hg emissions for 2010 through 2017 and except that any Hg Budget unit that would otherwise be allocated Hg allowances under § 60.4142(a) and (b), as well as under § 60.4142(a), (c), and (d), for the applicable control period will be assumed to be allocated no Hg allowances under § 60.4142(a), (c), and (d) for the applicable control period.

§ 60.4142 Hg allowance allocations.

(a)(1) The baseline heat input (in MMBtu) used with respect to Hg allowance allocations under paragraph (b) of this section for each Hg Budget unit will be:

(i) For units commencing operation before January 1, 2000: the average of the 3 highest amounts of the unit's adjusted control period heat input for 2000 through 2004; for units commencing operation on or after January 1, 2000, and before January 1, 2007: the average of the 3 highest amounts of the unit's adjusted control period heat input over the first 5 calendar years following the year in which the unit commenced operation, or the average of the 2 highest amounts of the unit's adjusted control period heat input over the first 4 calendar years following the year in which the unit commenced operation, or the maximum adjusted control period heat input over the first 1 to 3 calendar years following the year in which the unit commenced operation, depending on the maximum number (1 to 5) of such calendar years of data available to the permitting authority for determination of allowance allocations pursuant to sections

60.4141(a) or 60.4141(b)(1); with the adjusted control period heat input for each year calculated as the sum of the following:

(A) Any portion of the unit's control period heat input for the year that results from the unit's combustion of lignite, multiplied by 3.0;

(B) Any portion of the unit's control period heat input for the year that results from the unit's combustion of subbituminous coal, multiplied by 1.25; and

(C) Any portion of the unit's control period heat input for the year that is not covered by paragraph (a)(1)(i)(A) or (B) of this section, multiplied by 1.0.

(ii) For units commencing operation on or after January 1, 2007: the average of the 3 highest amounts of the unit's total converted control period heat input over the first 5 calendar years following the year in which the unit commenced operation, or the average of the 2 highest amounts of the unit's total converted control period heat input over the first 4 calendar years following the year in which the unit commenced operation, or the maximum total converted control period heat input over the first 1 to 3 calendar years following the year in which the unit commenced operation, depending on the maximum number (1 to 5) of such calendar years of data available to the permitting authority for determination of allowance allocations pursuant to section 60.4141(b)(1).

(iii) Notwithstanding paragraphs (a)(1)(i) and (ii) of this section, for any unit that is permanently retired and has not operated during the most recent five-year period for which the permitting authority has data upon which to base allowance allocations: zero (0).

(2)(i) A unit's control period heat input for a calendar year under paragraphs (a)(1)(i) of this section, and a unit's total ounces of Hg 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. The unit's types and amounts of fuel combusted, under paragraph (a)(1)(i) of this section, will be based on the best available data reported to the permitting authority for the unit.

(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 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 3,413 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) <u>For each control period in 2012 through 2017, the permitting authority will allocate to all Hg Budget units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of Hg allowances equal to 70 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under section 60.4140 (except as provided in paragraph (d) of this section). For each control period in 2010, 2011, and 2018 and thereafter, the permitting authority will allocate to all Hg Budget units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of Hg allowances equal to 95 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under section 60.4140 (except as provided in paragraph (d) of this section).</u>

(2) The permitting authority will allocate Hg allowances to each Hg Budget unit under paragraph (b)(1) of this section in an amount determined by multiplying the total amount of Hg allowances allocated under paragraph (b)(1) of this section by the ratio of the baseline heat input of such Hg Budget unit to the total amount of baseline heat input of all such Hg Budget units in the State and rounding to the nearest whole allowance as appropriate.

(c) <u>For each control period in 2010 and thereafter, the permitting authority will allocate Hg allowances to Hg Budget units in a State that are not allocated Hg allowances under paragraph (b) of this section because the units do not yet have a baseline heat input under paragraph (a) of this section or because the units have a baseline heat input but all Hg allowances available under paragraph (b) of this section for the control period are already allocated, in accordance with the following procedures:</u>

(1) <u>The permitting authority will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated Hg allowances equal to 5 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under section 60.4140, adjusted as necessary to ensure that the sum of all allocations made by the permitting authority does not exceed the State trading budget.</u>

(2) <u>The Hg designated representative of such a Hg Budget unit may submit to the permitting authority a request, in a format specified by the permitting authority, to be allocated Hg allowances, starting with the later of the control period in 2010 or the first control period after the control period in which the Hg Budget unit commences commercial operation and until the first control period for which the unit is allocated Hg allowances under paragraph (b) of this section. The Hg allowance allocation request must be submitted on or before May 1 of the first control period for which the Hg allowances are requested and after the date on which the Hg Budget unit commences commercial operation.</u>

(3) In a Hg allowance allocation request under paragraph (c)(2) of this section, the Hg designated representative may request for a control period Hg allowances in an amount not exceeding the Hg Budget unit's total ounces of Hg emissions during the control period immediately before such control period.

(4) The permitting authority will review each Hg allowance allocation request under paragraph (c)(2) of this section and will allocate Hg 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 May 1 of the control period, the permitting authority will determine the sum of the Hg 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 Hg 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 Hg allowances requested (as adjusted under paragraph (c)(4)(i) of this section) to each Hg Budget unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section.

(iv) If the amount of Hg 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 Hg Budget unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the Hg allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of Hg 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 using such rounding convention that results in allocation of the precise number of allowances in the set-aside.

(v) The permitting authority will notify each Hg designated representative that submitted an allowance allocation request of the amount of Hg allowances (if any) allocated for the control period to the Hg Budget 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 Hg allowances remain in the new unit set-aside for the control period, the permitting authority will allocate to each Hg unit that was allocated Hg allowances under paragraph (b) of this section an amount of Hg allowances equal to the total amount of such remaining unallocated Hg allowances, multiplied by the unit's allocation under paragraph (b) of this section, divided by 70 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under section 60.4140 for control periods 2012 through 2017, or 95 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under section 60.4140 for control periods 2010, 2011, and 2018 and thereafter, and rounded to the nearest whole allowance using such rounding convention that results in allocation of the precise number of allowances remaining in the set-aside.

62-204.800 Federal Regulations Adopted by Reference. All federal regulations cited throughout the air pollution rules of the Department are adopted and incorporated by reference in this rule. The purpose and effect of each such federal regulation is determined by the context in which it is cited. Procedural and substantive requirements in the incorporated federal regulations are binding as a matter of state law only where the context so provides.

(1) through (8) No change.

(9) Chapter 40, Code of Federal Regulations, Part 60, ~~Subpart C,~~ Emission Guidelines and Compliance Times.

(a) through (f) No change.

(g) Reserved.

(h) Coal-Fired Electric Steam Generating Units. 40 CFR 60, Subpart HHHH, Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units, revised as of July 1, 2005, amended June 9, 2006, at 71 FR 33388, is hereby adopted and incorporated by reference, subject to the provisions set forth at Rule 62-296.480, F.A.C.

(10) through (17) No change.

(18) Chapter 40, Code of Federal Regulations, Part 75, Continuous Emission Monitoring.

(a) The following subparts of 40 CFR Part 75, revised as of July 1, 2005 ~~July 1, 2001~~, or later as specifically indicated, are adopted and incorporated by reference:

1. 40 CFR 75, Subpart A, General~~; amended June 12, 2002, at 67 FR 40393; amended August 30, 2005, at 70 FR 51266~~.

2. 40 CFR 75, Subpart B, Monitoring Provisions~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503~~.

3. 40 CFR 75, Subpart C, Operation and Maintenance Requirements~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503~~.

4. 40 CFR 75, Subpart D, Missing Data Substitution Procedures~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002; at 67 FR 53503; amended September 9, 2002, at 67 FR 57274~~.

5. 40 CFR 75, Subpart E, Alternative Monitoring Systems~~; amended June 12, 2002, at 67 FR 40393~~.

6. 40 CFR 75, Subpart F, Recordkeeping Requirements~~; amended June 12, 2002, at 67 FR 40393; amended September 9, 2002, at 67 FR 57274~~.

7. 40 CFR 75, Subpart G, Reporting Requirements~~; amended June 12, 2002, at 67 FR 40393~~.

8. 40 CFR 75, Subpart H, NOx Mass Emissions Provisions~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503; amended September 9, 2002; at 67 FR 57274~~.

9. 40 CFR 75, Subpart I, Hg Mass Emission Provisions~~; promulgated May 18, 2005, at 70 FR 28605.~~

(b) The following appendices of 40 CFR Part 75, revised as of July 1, 2005 ~~July 1, 2001~~, or later as specifically indicated, are adopted and incorporated by reference:

1. Appendix A, Specifications and Test Procedures~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503; amended May 18, 2005, at 70 FR 28605~~.

2. Appendix B, Quality Assurance and Quality Control Procedures~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503; amended September 9, 2002, at 67 FR 57274; amended May 18, 2005, at 70 FR 28605~~.

3. Appendix C, Missing Data Estimation Procedures~~; amended June 12, 2002, at 67 FR 40393~~.

4. Appendix D, Optional SO2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503; amended September 9, 2002, at 67 FR 57274~~.

5. Appendix E, Optional NOx Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503~~.

6. Appendix F, Conversion Procedures~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503; amended May 18, 2005, at 70 FR 28605~~.

7. Appendix G, Determination of CO2 Emissions~~; amended June 12, 2002, at 67 FR 40393; amended September 9, 2002, at 67 FR 57274~~.

8. Appendix H, Revised Traceability Protocol No. 1.

9. Appendix I, Optional F-Factor/Fuel Flow Method.

10. Appendix J, Compliance Dates for Revised Recordkeeping Requirements and Missing Data Procedures.

11. Appendix K, Quality Assurance and Operating Procedures for Sorbent Trap Monitoring Systems~~; promulgated May 18, 2005, at 70 FR 28605~~.

(19) through (25) No change.

Specific Authority 403.061, 403.8055 FS. Law Implemented 403.031, 403.061, 403.087, 403.8055 FS. History–New 3-13-96, Amended 6-25-96, 10-7-96, 10-17-96, 12-20-96, 4-18-97, 6-18-97, 7-7-97, 10-3-97, 12-10-97, 3-2-98, 4-7-98, 5-20-98, 6-8-98, 10-19-98, 4-1-99, 7-1-99, 9-1-99, 10-1-99, 4-1-00, 10-1-00, 1-1-01, 8-1-01, 10-1-01, 4-1-02, 7-1-02, 10-1-02, 1-1-03, 4-1-03, 10-1-03, 1-1-04, 4-1-04, 7-1-04, 10-1-04, 1-1-05, 4-1-05, 7-1-05, 10-1-05, 1-1-06, 4-1-06, 9-4-06, ________.

62-210.200 Definitions. The following words and phrases when used in this chapter and in Chapters 62-212, 62-213, 62-214, 62-296, and 62-297, F.A.C., shall, unless content clearly indicates otherwise, have the following meanings:

(1) through (23) No change.

(24) "Alternate Designated Representative" –

(a) through (b) No change.

(c) For the purposes of the Hg Budget Trading Program, alternate designated representative shall mean "alternate Hg designated representative" as defined in 40 CFR 60.4102, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(25) through (87) No change.

(88) "Commence Operation" –

(a) through (b) No change.

(c) For the purposes of the Hg Budget Trading Program, commence operation shall mean "commence operation" as defined in 40 CFR 60.4102, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(d)~~(c)~~ Otherwise, to set into operation any emissions unit for any purpose.

(89) through (110) No change.

(111) "Designated Representative" –

(a) through (b) No change.

(c) For the purposes of the Hg Budget Trading Program, designated representative shall mean "Hg designated representative" as defined in 40 CFR 60.4102, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(112) through (149) No change.

(150) "Hg" – The regulated air pollutant mercury.

(151) "Hg Allowance" – A limited authorization issued by the Department to emit one ounce of mercury during a control period of the specified calendar year for which the authorization is allocated, or of any calendar year thereafter, under the Hg Budget Trading Program.

(152) "Hg Budget Source" – A facility that includes one or more Hg Budget units.

(153) "Hg Budget Trading Program" – The program implemented at Rule 62-296.480, F.A.C., which, upon approval by the U.S. Environmental Protection Agency, requires Hg Budget units in Florida to participate in the

multi-state air pollution control and emission reduction program administered by the U.S. Environmental Protection Agency pursuant to 40 CFR Part 60, Subpart HHHH, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(154) "Hg Budget Unit" – A unit that is subject to the Hg Budget Trading Program pursuant to 40 CFR 60.4104, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(150) through (312) renumbered (155) through (317) No change.

Specific Authority 403.061, 403.8055, FS. Law Implemented 403.031, 403.061, 403.087, 403.8055, FS. History-Formerly 17-2.100; Amended 2-9-93, 11-28-93, Formerly 17-210.200, Amended 11-23-94, 4-18-95, 1-2-96, 3-13-96, 3-21-96, 8-15-96, 10-7-96, 10-15-96, 5-20-97, 11-13-97, 2-5-98, 2-11-99, 4-16-01, 2-19-03,4-1-05, 7-6-05, 2-2-06, 4-1-06, 9-4-06, ______.

62-296.480 Implementation of Federal Clean Air Mercury Rule.

(1) Definitions. For purposes of this rule, the terms "Hg," "Hg allowance," "Hg Budget Trading Program," "Hg Budget source," and "Hg Budget unit" shall have the meanings given at Rule 62-210.200, F.A.C. All provisions of 40 CFR Part 60 cited within this rule are from 40 CFR Part 60, Subpart HHHH, adopted and incorporated by reference in Rule 62-204.800, F.A.C. Notwithstanding the first sentence of this paragraph, for purposes of the verbatim application of the cited provisions of 40 CFR Part 60, Subpart HHHH, as modified by the substitute language set forth in this rule, the definitions contained within such subpart shall apply, with the understanding that the term "permitting authority" shall mean the Department, the term "State" shall mean the State of Florida, and the phrase "permitting authority's title V operating permits regulations" shall mean Chapter 62-213, F.A.C.

(2) Orders. Prior to submitting any Hg allowance allocations to the Administrator pursuant to 40 CFR 60.4141(a), (b), or (c), the Department shall issue an administrative order pursuant to Chapter 120, F.S., to all Hg Budget sources giving notice and opportunity for hearing with regard to the amount of Hg allowances the Department intends to submit to the Administrator for each Hg Budget unit.

(3) Hg Allowance Transfers from the Department.

(a) Pursuant to the provisions of 40 CFR 60.4151(b), the Department shall establish a general account in its name and, for control periods 2012 through 2017, allocate to such account Hg allowances equal to 25 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under 40 CFR 60.4140, rounded to the nearest whole allowance.

(b) If, at the end of any of the control periods 2012 through 2017, a Hg Budget unit equipped with add-on Hg emission controls, a flue gas desulfurization system, or a combination flue gas desulfurization/selective catalytic reduction system reports Hg emissions in excess of the Hg allowances it was allocated for the control period in accordance with 40 CFR 60.4142(a) and (b), the Department, pursuant to the provisions of 40 CFR 60.4160 and by the allowance transfer deadline for the control period, shall transfer Hg allowances from its general account to the compliance account of the Hg budget unit in the amount by which the Hg emissions reported by the reporting deadline in accordance with 40 CFR 60.4170 through 60.4176 exceed the Hg allowances the unit was allocated for the control period in accordance with 40 CFR 60.4142(a) and (b), provided that:

1. The designated representative of the Hg Budget unit requests such transfer and certifies that during such control period the add-on Hg emission control equipment, flue gas desulfurization system, or combination flue gas

desulfurization/selective catalytic reduction system was operated at all times except for periods of unit or emission control equipment outage necessitated by maintenance operations or emergency conditions; and

2. The sum of the Hg allowances transferred from the Department's general account plus the Hg allowances allocated to the unit in accordance with 40 CFR 60.4142(a) and (b) for the control period shall not exceed the lesser of the Hg emissions reported by the reporting deadline in accordance with 40 CFR 60.4170 through 60.4176 or 1.35 times the amount of Hg allowances allocated to the unit in accordance with 40 CFR 60.4142(a) and (b), rounded to the nearest whole allowance.

(c) On or after May 1 of each control period, the Department shall determine how many Hg allowances of prior control period vintage remain in its general account. The Department shall make these allowances available to new Hg Budget units in accordance with the following procedure:

1. If the Department allocates allowances for the control period pursuant to 40 CFR 60.4142 (c)(4)(iv), the Department shall compute, for each Hg Budget unit that receives Hg allowances pursuant to such paragraph and for all such units in total, the shortfall between the number of Hg allowances requested, as determined pursuant to 40 CFR 60.4142(c)(4)(i), and the number of Hg allowances allocated pursuant to 40 CFR 60.4142(c)(4)(iv).

2. If the number of Hg allowances of prior control period vintage in the Department's general account is greater than the total shortfall of Hg allowances for all applicable Hg Budget units as computed in subparagraph 62-296.480(3)(c)1, F.A.C., the Department, pursuant to the provisions of 40 CFR 60.4160, shall transfer from its general account to the compliance account of each such unit an amount of Hg allowances equal to the unit's shortfall.

3. If the number of Hg allowances of prior control period vintage in the Department's general account is less than the total shortfall of Hg allowances for all applicable Hg Budget units as computed in subparagraph 62-296.480(3)(c)1, F.A.C., the Department, pursuant to the provisions of 40 CFR 60.4160, shall transfer from its general account to the compliance account of each such unit an amount of Hg allowances equal to the number of Hg allowances of prior control period vintage in the Department's general account times the unit's shortfall divided by the total shortfall, rounded to the nearest whole allowance using such rounding convention that results in allocation of the precise number of Hg allowances of prior control period vintage in the general account.

4. The Department shall submit all Hg allowance transfers required by this paragraph to the Administrator between October 31 of each control period and the allowance transfer deadline for the control period.

(d) The Department shall not transfer any Hg Budget allowances from its general account except as provided at paragraphs 62-296.480(3)(b) and (c), F.A.C.

(4) Hg Budget Trading Program. Except as otherwise provided herein, all provisions of the following sections of 40 CFR Part 60, Subpart HHHH, shall apply verbatim.

(a) Hg Budget Trading Program General Provisions, 40 CFR 60.4101 through 60.4108.

(b) Hg Designated Representative for Hg Budget Sources, 40 CFR 60.4110 through 60.4114.

(c) Permits, 40 CFR 60.4120 through 60.4130.

(d) Hg Allowance Allocations, 40 CFR 60.4140 through 60.4142, provided that substitute language, as set forth below, shall apply in lieu of the indicated provisions.

1. In lieu of the language at 40 CFR 60.4141(a), substitute:

"By October 31, 2006, the permitting authority will submit to the Administrator the Hg allowance allocations, in a format prescribed by the Administrator and in accordance with sections 60.4142(a) and (b), for the control periods in 2010, 2011, and 2012."

2. In lieu of the language at 40 CFR 60.4141(b)(1), substitute:

"By October 31, 2009, and October 31 of each third year thereafter, the permitting authority will submit to the Administrator the Hg allowance allocations, in a format prescribed by the Administrator and in accordance with sections 60.4142(a) and (b), for the control periods in the fourth, fifth, and sixth years after the year of the applicable deadline for submission under this paragraph."

3. In lieu of the language at 40 CFR 60.4142(a)(1), substitute:

"The baseline heat input (in MMBtu) used with respect to Hg allowance allocations under paragraph (b) of this section for each Hg Budget unit will be:

(i) For units commencing operation before January 1, 2000: the average of the 3 highest amounts of the unit's adjusted control period heat input for 2000 through 2004; for units commencing operation on or after January 1, 2000, and before January 1, 2007: the average of the 3 highest amounts of the unit's adjusted control period heat input over the first 5 calendar years following the year in which the unit commenced operation, or the average of the 2 highest amounts of the unit's adjusted control period heat input over the first 4 calendar years following the year in which the unit commenced operation, or the maximum adjusted control period heat input over the first 1 to 3 calendar years following the year in which the unit commenced operation, depending on the maximum number (1 to 5) of such calendar years of data available to the permitting authority for determination of allowance allocations pursuant to sections 60.4141(a) or 60.4141(b)(1); with the adjusted control period heat input for each year calculated as the sum of the following:

(A) Any portion of the unit's control period heat input for the year that results from the unit's combustion of lignite, multiplied by 3.0;

(B) Any portion of the unit's control period heat input for the year that results from the unit's combustion of subbituminous coal, multiplied by 1.25; and

(C) Any portion of the unit's control period heat input for the year that is not covered by paragraph (a)(1)(i)(A) or (B) of this section, multiplied by 1.0.

(ii) For units commencing operation on or after January 1, 2007: the average of the 3 highest amounts of the unit's total converted control period heat input over the first 5 calendar years following the year in which the unit commenced operation, or the average of the 2 highest amounts of the unit's total converted control period heat input over the first 4 calendar years following the year in which the unit commenced operation, or the maximum total converted control period heat input over the first 1 to 3 calendar years following the year in which the unit commenced operation, depending on the maximum number (1 to 5) of such calendar years of data available to the permitting authority for determination of allowance allocations pursuant to section 60.4141(b)(1).

(iii) Notwithstanding paragraphs (a)(1)(i) and (ii), for any unit that is permanently retired and has not operated during the most recent five-year period for which the permitting authority has data upon which to base allowance allocations: zero (0)."

4. In lieu of the language at 40 CFR 60.4142(b)(1), substitute:

"For each control period in 2012 through 2017, the permitting authority will allocate to all Hg Budget units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of Hg allowances equal to 70 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under section 60.4140 (except as provided in paragraph (d) of this section). For each control period in 2010, 2011, and 2018 and thereafter, the permitting authority will allocate to all Hg Budget units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of Hg allowances equal to 95 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under section 60.4140 (except as provided in paragraph (d) of this section)."

5. In lieu of the language at 40 CFR 60.4142(c), substitute:

"For each control period in 2010 and thereafter, the permitting authority will allocate Hg allowances to Hg Budget units in a State that are not allocated Hg allowances under paragraph (b) of this section because the units do not yet have a baseline heat input under paragraph (a) of this section or because the units have a baseline heat input but all Hg allowances available under paragraph (b) of this section for the control period are already allocated, in accordance with the following procedures:"

6. In lieu of the language at 40 CFR 60.4142(c)(1), substitute:

"The permitting authority will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated Hg allowances equal to 5 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under section 60.4140, adjusted as necessary to ensure that the sum of all allocations made by the permitting authority does not exceed the State trading budget."

7. In lieu of the language at 40 CFR 60.4142(c)(2), substitute:

"The Hg designated representative of such a Hg Budget unit may submit to the permitting authority a request, in a format specified by the permitting authority, to be allocated Hg allowances, starting with the later of the control period in 2010 or the first control period after the control period in which the Hg Budget unit commences commercial operation and until the first control period for which the unit is allocated Hg allowances under paragraph (b) of this section. The Hg allowance allocation request must be submitted on or before May 1 of the first control period for which the Hg allowances are requested and after the date on which the Hg Budget unit commences commercial operation."

8. In lieu of the language at 40 CFR 60.4142(c)(4)(ii), substitute:

"On or after May 1 of the control period, the permitting authority will determine the sum of the Hg 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."

9. In lieu of the language at 40 CFR 60.4142(c)(4)(iv), substitute:

"If the amount of Hg 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 Hg Budget unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the Hg allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of Hg 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 using such rounding convention that results in allocation of the precise number of allowances in the new unit set-aside."

10. In lieu of the language at 40 CFR 60.4142(d), substitute:

"If, after completion of the procedures under paragraph (c)(4) of this section for a control period, any unallocated Hg allowances remain in the new unit set-aside for the control period, the permitting authority will allocate to each Hg unit that was allocated Hg allowances under paragraph (b) of this section an amount of Hg allowances equal to the total amount of such remaining unallocated Hg allowances, multiplied by the unit's allocation under paragraph (b) of this section, divided by 70 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under section 60.4140 for control periods 2012 through 2017, or 95 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under section 60.4140 for control periods 2010, 2011, and 2018 and thereafter, and rounded to the nearest whole allowance using such rounding convention that results in allocation of the precise number of allowances remaining in the new unit set-aside."

(e) Hg Allowance Tracking System, 40 CFR 60.4150 through 60.4157.

(f) Hg Allowance Transfers, 40 CFR 60.4160 through 60.4162.

(g) Hg Monitoring and Reporting, 40 CFR 60.4170 through 60.4176.

Specific Authority 403.061, 403.087 FS. Law Implemented 403.031, 403.061, 403.087 FS. History – New ______.

62-204.800 Federal Regulations Adopted by Reference. All federal regulations cited throughout the air pollution rules of the Department are adopted and incorporated by reference in this rule. The purpose and effect of each such federal regulation is determined by the context in which it is cited. Procedural and substantive requirements in the incorporated federal regulations are binding as a matter of state law only where the context so provides.

(1) through (8) No change.

(9) Chapter 40, Code of Federal Regulations, Part 60, ~~Subpart C,~~ Emission Guidelines and Compliance Times.

(a) through (f) No change.

<u>(g) Reserved.</u>

<u>(h) Coal-Fired Electric Steam Generating Units. 40 CFR 60, Subpart HHHH, Emission Guidelines and Compliance Times for Coal-Fired Electric Steam Generating Units, revised as of July 1, 2005, amended June 9, 2006, at 71 FR 33388, is hereby adopted and incorporated by reference, subject to the provisions set forth at Rule 62-296.480, F.A.C.</u>

(10) through (17) No change.

(18) Chapter 40, Code of Federal Regulations, Part 75, Continuous Emission Monitoring.

(a) The following subparts of 40 CFR Part 75, revised as of <u>July 1, 2005</u> ~~July 1, 2001~~, or later as specifically indicated, are adopted and incorporated by reference:

1. 40 CFR 75, Subpart A, General~~; amended June 12, 2002, at 67 FR 40393; amended August 30, 2005, at 70 FR 51266~~.

2. 40 CFR 75, Subpart B, Monitoring Provisions~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503~~.

3. 40 CFR 75, Subpart C, Operation and Maintenance Requirements~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503~~.

4. 40 CFR 75, Subpart D, Missing Data Substitution Procedures~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002; at 67 FR 53503; amended September 9, 2002, at 67 FR 57274~~.

5. 40 CFR 75, Subpart E, Alternative Monitoring Systems~~; amended June 12, 2002, at 67 FR 40393~~.

6. 40 CFR 75, Subpart F, Recordkeeping Requirements~~; amended June 12, 2002, at 67 FR 40393; amended September 9, 2002, at 67 FR 57274~~.

7. 40 CFR 75, Subpart G, Reporting Requirements~~; amended June 12, 2002, at 67 FR 40393~~.

8. 40 CFR 75, Subpart H, NOx Mass Emissions Provisions~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503; amended September 9, 2002; at 67 FR 57274~~.

9. 40 CFR 75, Subpart I, Hg Mass Emission Provisions~~; promulgated May 18, 2005, at 70 FR 28605.~~

(b) The following appendices of 40 CFR Part 75, revised as of July 1, 2005 ~~July 1, 2001~~, or later as specifically indicated, are adopted and incorporated by reference:

1. Appendix A, Specifications and Test Procedures~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503; amended May 18, 2005, at 70 FR 28605~~.

2. Appendix B, Quality Assurance and Quality Control Procedures~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503; amended September 9, 2002, at 67 FR 57274; amended May 18, 2005, at 70 FR 28605~~.

3. Appendix C, Missing Data Estimation Procedures~~; amended June 12, 2002, at 67 FR 40393~~.

4. Appendix D, Optional SO2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503; amended September 9, 2002, at 67 FR 57274~~.

5. Appendix E, Optional NOx Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503~~.

6. Appendix F, Conversion Procedures~~; amended June 12, 2002, at 67 FR 40393; amended August 16, 2002, at 67 FR 53503; amended May 18, 2005, at 70 FR 28605~~.

7. Appendix G, Determination of CO2 Emissions~~; amended June 12, 2002, at 67 FR 40393; amended September 9, 2002, at 67 FR 57274~~.

8. Appendix H, Revised Traceability Protocol No. 1.

9. Appendix I, Optional F-Factor/Fuel Flow Method.

10. Appendix J, Compliance Dates for Revised Recordkeeping Requirements and Missing Data Procedures.

11. Appendix K, Quality Assurance and Operating Procedures for Sorbent Trap Monitoring Systems~~; promulgated May 18, 2005, at 70 FR 28605~~.

(19) through (25) No change.

Specific Authority 403.061, 403.8055 FS. Law Implemented 403.031, 403.061, 403.087, 403.8055 FS. History–New 3-13-96, Amended 6-25-96, 10-7-96, 10-17-96, 12-20-96, 4-18-97, 6-18-97, 7-7-97, 10-3-97, 12-10-97, 3-2-98, 4-7-98, 5-20-98, 6-8-98, 10-19-98, 4-1-99, 7-1-99, 9-1-99, 10-1-99, 4-1-00, 10-1-00, 1-1-01, 8-1-01, 10-1-01, 4-1-02, 7-1-02, 10-1-02, 1-1-03, 4-1-03, 10-1-03, 1-1-04, 4-1-04, 7-1-04, 10-1-04, 1-1-05, 4-1-05, 7-1-05, 10-1-05, 1-1-06, 4-1-06, 9-4-06,________.

62-210.200 Definitions. The following words and phrases when used in this chapter and in Chapters 62-212, 62-213, 62-214, 62-296, and 62-297, F.A.C., shall, unless content clearly indicates otherwise, have the following meanings:

(1) through (23) No change.

(24) "Alternate Designated Representative" –

(a) through (b) No change.

(c) For the purposes of the Hg Budget Trading Program, alternate designated representative shall mean "alternate Hg designated representative" as defined in 40 CFR 60.4102, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(25) through (87) No change.

(88) "Commence Operation" –

(a) through (b) No change.

(c) For the purposes of the Hg Budget Trading Program, commence operation shall mean "commence operation" as defined in 40 CFR 60.4102, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(d)~~(c)~~ Otherwise, to set into operation any emissions unit for any purpose.

(89) through (110) No change.

(111) "Designated Representative" –

(a) through (b) No change.

(c) For the purposes of the Hg Budget Trading Program, designated representative shall mean "Hg designated representative" as defined in 40 CFR 60.4102, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(112) through (149) No change.

(150) "Hg" – The regulated air pollutant mercury.

(151) "Hg Allowance" – A limited authorization issued by the Department to emit one ounce of mercury during a control period of the specified calendar year for which the authorization is allocated, or of any calendar year thereafter, under the Hg Budget Trading Program.

(152) "Hg Budget Source" – A facility that includes one or more Hg Budget units.

(153) "Hg Budget Trading Program" – The program implemented at Rule 62-296.480, F.A.C., which, upon approval by the U.S. Environmental Protection Agency, requires Hg Budget units in Florida to participate in the

multi-state air pollution control and emission reduction program administered by the U.S. Environmental Protection Agency pursuant to 40 CFR Part 60, Subpart HHHH, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(154) "Hg Budget Unit" – A unit that is subject to the Hg Budget Trading Program pursuant to 40 CFR 60.4104, adopted and incorporated by reference in Rule 62-204.800, F.A.C.

(150) through (312) renumbered (155) through (317) No change.

Specific Authority 403.061, 403.8055, FS. Law Implemented 403.031, 403.061, 403.087, 403.8055, FS. History-Formerly 17-2.100; Amended 2-9-93, 11-28-93, Formerly 17-210.200, Amended 11-23-94, 4-18-95, 1-2-96, 3-13-96, 3-21-96, 8-15-96, 10-7-96, 10-15-96, 5-20-97, 11-13-97, 2-5-98, 2-11-99, 4-16-01, 2-19-03,4-1-05, 7-6-05, 2-2-06, 4-1-06, 9-4-06, ______.

62-296.480 Implementation of Federal Clean Air Mercury Rule.

(1) Definitions. For purposes of this rule, the terms "Hg," "Hg allowance," "Hg Budget Trading Program," "Hg Budget source," and "Hg Budget unit" shall have the meanings given at Rule 62-210.200, F.A.C. All provisions of 40 CFR Part 60 cited within this rule are from 40 CFR Part 60, Subpart HHHH, adopted and incorporated by reference in Rule 62-204.800, F.A.C. Notwithstanding the first sentence of this paragraph, for purposes of the verbatim application of the cited provisions of 40 CFR Part 60, Subpart HHHH, as modified by the substitute language set forth in this rule, the definitions contained within such subpart shall apply, with the understanding that the term "permitting authority" shall mean the Department, the term "State" shall mean the State of Florida, and the phrase "permitting authority's title V operating permits regulations" shall mean Chapter 62-213, F.A.C.

(2) Orders. Prior to submitting any Hg allowance allocations to the Administrator pursuant to 40 CFR 60.4141(a), (b), or (c), the Department shall issue an administrative order pursuant to Chapter 120, F.S., to all Hg Budget sources giving notice and opportunity for hearing with regard to the amount of Hg allowances the Department intends to submit to the Administrator for each Hg Budget unit.

(3) Hg Allowance Transfers from the Department.

(a) Pursuant to the provisions of 40 CFR 60.4151(b), the Department shall establish a general account in its name and, for control periods 2012 through 2017, allocate to such account Hg allowances equal to 25 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under 40 CFR 60.4140, rounded to the nearest whole allowance.

(b) If, at the end of any of the control periods 2012 through 2017, a Hg Budget unit equipped with add-on Hg emission controls, a flue gas desulfurization system, or a combination flue gas desulfurization/selective catalytic reduction system reports Hg emissions in excess of the Hg allowances it was allocated for the control period in accordance with 40 CFR 60.4142(a) and (b), the Department, pursuant to the provisions of 40 CFR 60.4160 and by the allowance transfer deadline for the control period, shall transfer Hg allowances from its general account to the compliance account of the Hg budget unit in the amount by which the Hg emissions reported by the reporting deadline in accordance with 40 CFR 60.4170 through 60.4176 exceed the Hg allowances the unit was allocated for the control period in accordance with 40 CFR 60.4142(a) and (b), provided that:

1. The designated representative of the Hg Budget unit requests such transfer and certifies that during such control period the add-on Hg emission control equipment, flue gas desulfurization system, or combination flue gas

desulfurization/selective catalytic reduction system was operated at all times except for periods of unit or emission control equipment outage necessitated by maintenance operations or emergency conditions; and

2. The sum of the Hg allowances transferred from the Department's general account plus the Hg allowances allocated to the unit in accordance with 40 CFR 60.4142(a) and (b) for the control period shall not exceed the lesser of the Hg emissions reported by the reporting deadline in accordance with 40 CFR 60.4170 through 60.4176 or 1.35 times the amount of Hg allowances allocated to the unit in accordance with 40 CFR 60.4142(a) and (b), rounded to the nearest whole allowance.

(c) On or after May 1 of each control period, the Department shall determine how many Hg allowances of prior control period vintage remain in its general account. The Department shall make these allowances available to new Hg Budget units in accordance with the following procedure:

1. If the Department allocates allowances for the control period pursuant to 40 CFR 60.4142 (c)(4)(iv), the Department shall compute, for each Hg Budget unit that receives Hg allowances pursuant to such paragraph and for all such units in total, the shortfall between the number of Hg allowances requested, as determined pursuant to 40 CFR 60.4142(c)(4)(i), and the number of Hg allowances allocated pursuant to 40 CFR 60.4142(c)(4)(iv).

2. If the number of Hg allowances of prior control period vintage in the Department's general account is greater than the total shortfall of Hg allowances for all applicable Hg Budget units as computed in subparagraph 62-296.480(3)(c)1, F.A.C., the Department, pursuant to the provisions of 40 CFR 60.4160, shall transfer from its general account to the compliance account of each such unit an amount of Hg allowances equal to the unit's shortfall.

3. If the number of Hg allowances of prior control period vintage in the Department's general account is less than the total shortfall of Hg allowances for all applicable Hg Budget units as computed in subparagraph 62-296.480(3)(c)1, F.A.C., the Department, pursuant to the provisions of 40 CFR 60.4160, shall transfer from its general account to the compliance account of each such unit an amount of Hg allowances equal to the number of Hg allowances of prior control period vintage in the Department's general account times the unit's shortfall divided by the total shortfall, rounded to the nearest whole allowance using such rounding convention that results in allocation of the precise number of Hg allowances of prior control period vintage in the general account.

4. The Department shall submit all Hg allowance transfers required by this paragraph to the Administrator between October 31 of each control period and the allowance transfer deadline for the control period.

(d) The Department shall not transfer any Hg Budget allowances from its general account except as provided at paragraphs 62-296.480(3)(b) and (c), F.A.C.

(4) Hg Budget Trading Program. Except as otherwise provided herein, all provisions of the following sections of 40 CFR Part 60, Subpart HHHH, shall apply verbatim.

(a) Hg Budget Trading Program General Provisions, 40 CFR 60.4101 through 60.4108.

(b) Hg Designated Representative for Hg Budget Sources, 40 CFR 60.4110 through 60.4114.

(c) Permits, 40 CFR 60.4120 through 60.4130.

(d) Hg Allowance Allocations, 40 CFR 60.4140 through 60.4142, provided that substitute language, as set forth below, shall apply in lieu of the indicated provisions.

1. In lieu of the language at 40 CFR 60.4141(a), substitute:

"By October 31, 2006, the permitting authority will submit to the Administrator the Hg allowance allocations, in a format prescribed by the Administrator and in accordance with sections 60.4142(a) and (b), for the control periods in 2010, 2011, and 2012."

2. In lieu of the language at 40 CFR 60.4141(b)(1), substitute:

"By October 31, 2009, and October 31 of each third year thereafter, the permitting authority will submit to the Administrator the Hg allowance allocations, in a format prescribed by the Administrator and in accordance with sections 60.4142(a) and (b), for the control periods in the fourth, fifth, and sixth years after the year of the applicable deadline for submission under this paragraph."

3. In lieu of the language at 40 CFR 60.4142(a)(1), substitute:

"The baseline heat input (in MMBtu) used with respect to Hg allowance allocations under paragraph (b) of this section for each Hg Budget unit will be:

(i) For units commencing operation before January 1, 2000: the average of the 3 highest amounts of the unit's adjusted control period heat input for 2000 through 2004; for units commencing operation on or after January 1, 2000, and before January 1, 2007: the average of the 3 highest amounts of the unit's adjusted control period heat input over the first 5 calendar years following the year in which the unit commenced operation, or the average of the 2 highest amounts of the unit's adjusted control period heat input over the first 4 calendar years following the year in which the unit commenced operation, or the maximum adjusted control period heat input over the first 1 to 3 calendar years following the year in which the unit commenced operation, depending on the maximum number (1 to 5) of such calendar years of data available to the permitting authority for determination of allowance allocations pursuant to sections 60.4141(a) or 60.4141(b)(1); with the adjusted control period heat input for each year calculated as the sum of the following:

(A) Any portion of the unit's control period heat input for the year that results from the unit's combustion of lignite, multiplied by 3.0;

(B) Any portion of the unit's control period heat input for the year that results from the unit's combustion of subbituminous coal, multiplied by 1.25; and

(C) Any portion of the unit's control period heat input for the year that is not covered by paragraph (a)(1)(i)(A) or (B) of this section, multiplied by 1.0.

(ii) For units commencing operation on or after January 1, 2007: the average of the 3 highest amounts of the unit's total converted control period heat input over the first 5 calendar years following the year in which the unit commenced operation, or the average of the 2 highest amounts of the unit's total converted control period heat input over the first 4 calendar years following the year in which the unit commenced operation, or the maximum total converted control period heat input over the first 1 to 3 calendar years following the year in which the unit commenced operation, depending on the maximum number (1 to 5) of such calendar years of data available to the permitting authority for determination of allowance allocations pursuant to section 60.4141(b)(1).

(iii) Notwithstanding paragraphs (a)(1)(i) and (ii), for any unit that is permanently retired and has not operated during the most recent five-year period for which the permitting authority has data upon which to base allowance allocations: zero (0)."

4. In lieu of the language at 40 CFR 60.4142(b)(1), substitute:

"For each control period in 2012 through 2017, the permitting authority will allocate to all Hg Budget units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of Hg allowances equal to 70 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under section 60.4140 (except as provided in paragraph (d) of this section). For each control period in 2010, 2011, and 2018 and thereafter, the permitting authority will allocate to all Hg Budget units in the State that have a baseline heat input (as determined under paragraph (a) of this section) a total amount of Hg allowances equal to 95 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under section 60.4140 (except as provided in paragraph (d) of this section)."

5. In lieu of the language at 40 CFR 60.4142(c), substitute:

"For each control period in 2010 and thereafter, the permitting authority will allocate Hg allowances to Hg Budget units in a State that are not allocated Hg allowances under paragraph (b) of this section because the units do not yet have a baseline heat input under paragraph (a) of this section or because the units have a baseline heat input but all Hg allowances available under paragraph (b) of this section for the control period are already allocated, in accordance with the following procedures:"

6. In lieu of the language at 40 CFR 60.4142(c)(1), substitute:

"The permitting authority will establish a separate new unit set-aside for each control period. Each new unit set-aside will be allocated Hg allowances equal to 5 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under section 60.4140, adjusted as necessary to ensure that the sum of all allocations made by the permitting authority does not exceed the State trading budget."

7. In lieu of the language at 40 CFR 60.4142(c)(2), substitute:

"The Hg designated representative of such a Hg Budget unit may submit to the permitting authority a request, in a format specified by the permitting authority, to be allocated Hg allowances, starting with the later of the control period in 2010 or the first control period after the control period in which the Hg Budget unit commences commercial operation and until the first control period for which the unit is allocated Hg allowances under paragraph (b) of this section. The Hg allowance allocation request must be submitted on or before May 1 of the first control period for which the Hg allowances are requested and after the date on which the Hg Budget unit commences commercial operation."

8. In lieu of the language at 40 CFR 60.4142(c)(4)(ii), substitute:

"On or after May 1 of the control period, the permitting authority will determine the sum of the Hg 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."

9. In lieu of the language at 40 CFR 60.4142(c)(4)(iv), substitute:

"If the amount of Hg 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 Hg Budget unit covered by an allowance allocation request accepted under paragraph (c)(4)(i) of this section the amount of the Hg allowances requested (as adjusted under paragraph (c)(4)(i) of this section), multiplied by the amount of Hg 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 using such rounding convention that results in allocation of the precise number of allowances in the new unit set-aside."

10. In lieu of the language at 40 CFR 60.4142(d), substitute:

"If, after completion of the procedures under paragraph (c)(4) of this section for a control period, any unallocated Hg allowances remain in the new unit set-aside for the control period, the permitting authority will allocate to each Hg unit that was allocated Hg allowances under paragraph (b) of this section an amount of Hg allowances equal to the total amount of such remaining unallocated Hg allowances, multiplied by the unit's allocation under paragraph (b) of this section, divided by 70 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under section 60.4140 for control periods 2012 through 2017, or 95 percent of the amount of ounces (i.e., tons multiplied by 32,000 ounces/ton) of Hg emissions in the State trading budget under section 60.4140 for control periods 2010, 2011, and 2018 and thereafter, and rounded to the nearest whole allowance using such rounding convention that results in allocation of the precise number of allowances remaining in the new unit set-aside."

(e) Hg Allowance Tracking System, 40 CFR 60.4150 through 60.4157.

(f) Hg Allowance Transfers, 40 CFR 60.4160 through 60.4162.

(g) Hg Monitoring and Reporting, 40 CFR 60.4170 through 60.4176.

Specific Authority 403.061, 403.087 FS. Law Implemented 403.031, 403.061, 403.087 FS. History – New ______.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

In Re: **In the Matter of Mercury Allowance Allocations for Calendar Years 2010, 2011, and 2012**

ORDER ALLOCATING MERCURY ALLOWANCES PURSUANT TO FLORIDA ADMINISTRATIVE CODE RULE 62-296.480 AND TITLE 40 OF THE CODE OF FEDERAL REGULATIONS, PART 60, SUBPART HHHH, FOR CALENDAR YEARS 2010, 2011 AND 2012

The Department of Environmental Protection (Department) takes agency action to allocate allowances for mercury emissions (Hg allowances), in ounces per year, for calendar years 2010, 2011 and 2012 to Hg Budget units, as set forth in Exhibit A.

The Department's proposed agency action shall become final unless a timely petition for an administrative hearing is filed pursuant to Sections 120.569 and 120.57, Florida Statutes (F.S.), before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below.

A person whose substantial interests are affected by the proposed agency action may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida, 32399-3000.

Petitions filed by the owners or operators of Hg Budget units must be filed within twenty-one days of receipt of this notice of intent. Petitions filed by other persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within twenty-one days of publication of the public notice or within twenty-one days of receipt of this notice, whichever occurs first. Under Section 120.60(3), F.S., however, any person who asked the Department for notice of agency action may file a petition within twenty-one days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicants at the addresses indicated below at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention (in a proceeding initiated by another party) will be only at the discretion of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information:

(a) The name and address of each agency affected and the Department's Division of Air Resource Management's ARMS or federal identification number, if known.

(b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding;

(c) A statement of when and how petitioner received notice of the agency action or proposed action;

(d) An explanation of how the petitioner's substantial interests are or will be affected by the agency action or proposed action;

(e) A statement of all material facts disputed by the petitioner or a statement that there are no disputed facts;

(f) A statement of the ultimate facts alleged, including a statement of the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action;

(g) A statement of the specific rules or statutes that the petitioner contends require reversal or modification of the agency's proposed action, including an explanation of how the alleged facts relate to the specific rules or statutes; and

(h) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation is not available in this proceeding.

NOTICE OF APPEAL RIGHTS

Any party to this order has the right to seek judicial review of it under Section 120.68, F.S., by filing a notice of appeal under Rule 9.110 of the Florida rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice must be filed within thirty days after this order is filed with the clerk of the Department.

DONE AND ORDERED this 9th day of November, 2006 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

JOSEPH KAHN, Director
Division of Air Resource Management
Mail Station 5500
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 488-0114

FILING AND ACKNOWLEDGMENT

FILED, on this date, pursuant to §120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged. All copies were mailed before the close of business on the date below to the persons listed.

Barbara Friday 11/9/06

Clerk (or Deputy Clerk) Date

Copies furnished to the persons listed at Exhibit B.

Exhibit A
Hg Budget Units and Hg Allowance Allocations

Owner/Company Name	Hg Budget Source (Facility Name)	ARMS Facility ID	Federal Facility ID	Hg Budget Unit ARMS Unit ID	Hg Budget Unit Federal Unit ID	Hg Allowance Allocation 2010 (oz.)	Hg Allowance Allocation 2011 (oz.)	Hg Allowance Allocation 2012 (oz.)
Cedar Bay Cogeneration, Inc.	Cedar Bay Generating Company	310337	10672		GEN1	343	343	253
Cedar Bay Cogeneration, Inc.	Cedar Bay Generating Company	310337	10672	2	GEN1	328	328	242
Cedar Bay Cogeneration, Inc.	Cedar Bay Generating Company	310337	10672	3	GEN1	333	333	245
City of Gainesville, GRU	Deerhaven Generating Station	10006	663	5	B2	689	689	508
Florida Crushed Stone Co., Inc.	Central Power And Lime, Inc.	530021	10333	18	GEN1	466	466	343
Gulf Power Company	Lansing Smith Generating Plant	50014	643	1	1	551	551	406
Gulf Power Company	Lansing Smith Generating Plant	50014	643	2	2	639	639	471
Gulf Power Company	Crist Electric Generating Plant	330045	641	4	4	245	245	180
Gulf Power Company	Crist Electric Generating Plant	330045	641	5	5	269	269	198
Gulf Power Company	Crist Electric Generating Plant	330045	641	6	6	811	811	598
Gulf Power Company	Crist Electric Generating Plant	330045	641	7	7	1,538	1,538	1,133
Gulf Power Company	Scholz Electric Generating Plant	630014	642	1	1	104	104	76
Gulf Power Company	Scholz Electric Generating Plant	630014	642	2	2	120	120	89
Indiantown Cogeneration, L.P.	Indiantown Cogeneration Facility	850102	50976	1	GEN1	1,035	1,035	763
JEA	St. Johns River Power Park	310045	207	16	1	2,437	2,437	1,796
JEA	St. Johns River Power Park	310045	207	17	2	2,289	2,289	1,687
JEA	Northside Power Plant	310045	667	27	1A	795	795	585
JEA	Northside Power Plant	310045	667	26	2A	770	770	567
Lakeland Electric	C D McIntosh Jr. Power Plant	1050004	676	6	3	1,300	1,300	958
Orlando Utilities Commission	Curtis H. Stanton Energy Center	950137	564	1	1	1,431	1,431	1,055
Orlando Utilities Commission	Curtis H. Stanton Energy Center	950137	564	2	2	1,418	1,418	1,045
Progress Energy Florida, Inc.	Crystal River Power Plant	170004	628	1	1	1,042	1,042	768
Progress Energy Florida, Inc.	Crystal River Power Plant	170004	628	2	2	1,342	1,342	989
Progress Energy Florida, Inc.	Crystal River Power Plant	170004	628	4	4	2,371	2,371	1,747
Progress Energy Florida, Inc.	Crystal River Power Plant	170004	628	3	5	2,338	2,338	1,723
Seminole Electric Cooperative	Seminole Generating Station	1070025	136	1	1	2,158	2,158	1,590
Seminole Electric Cooperative	Seminole Generating Station	1070025	136	2	2	2,290	2,290	1,687
Tampa Electric Company	Big Bend Station	570039	645	1	BB01	1,151	1,151	848
Tampa Electric Company	Big Bend Station	570039	645	2	BB02	1,173	1,173	865
Tampa Electric Company	Big Bend Station	570039	645	3	BB03	1,090	1,090	803
Tampa Electric Company	Big Bend Station	570039	645	4	BB04	1,462	1,462	1,077
Tampa Electric Company	Gannon Station	570040	646	1	GB01	285	285	210
Tampa Electric Company	Gannon Station	570040	646	2	GB02	269	269	198
Tampa Electric Company	Gannon Station	570040	646	3	GB03	361	361	266
Tampa Electric Company	Gannon Station	570040	646	4	GB04	390	390	287
Tampa Electric Company	Gannon Station	570040	646	5	GB05	459	459	338
Tampa Electric Company	Gannon Station	570040	646	6	GB06	799	799	589
Tampa Electric Company	Polk Power Station	1050233	7242	1	1	561	561	414
Total for Hg Budget Units (oz.)						**37,452**	**37,452**	**27,597**
New Unit Set Aside (oz.)						**1,972**	**1,972**	**1,971**
To DEP General Account (oz.)						**0**	**0**	**9,856**
Grand Total (oz.)						**39,424**	**39,424**	**39,424**

Exhibit B
Persons Furnished Copies of this Order

Owner/Company Name	Hg Budget Source (Facility Name)	Title V Primary Responsible Official (by certified mail)	Courtesy Copy
Cedar Bay Cogeneration, Inc.	Cedar Bay Generating Company	Tracy Patterson P.O. Box 26324 Jacksonville, FL 32226-6324	
City of Gainesville, GRU	Deerhaven Generating Station	Randy Casserleigh P.O Box 147117 (D38) Gainesville, FL 32614-7117	
Florida Crushed Stone Co., Inc.	Central Power And Lime, Inc.	Terry Woodard P.O. Box 10269 Brooksville, FL 34603	
Gulf Power Company	Lansing Smith Generating Plant	Penny M. Manuel One Energy Place Pensacola, FL 32520-0100	
Gulf Power Company	Crist Electric Generating Plant	Penny M. Manuel One Energy Place Pensacola, FL 32520-0100	
Gulf Power Company	Scholz Electric Generating Plant	Penny M. Manuel One Energy Place Pensacola, FL 32520-0100	
Indiantown Cogeneration, L.P.	Indiantown Cogeneration Facility	Gary E. Willer P.O. Box 1799 Indiantown, FL 34953	
JEA	St. Johns River Power Park	James M. Chansler 21 West Church St., Tower 8 Jacksonville, FL 32202	
JEA	Northside Power Plant	James M. Chansler 21 West Church St., Tower 8 Jacksonville, FL 32202	
Lakeland Electric	C D McIntosh Jr. Power Plant	Timothy L. Bachand 501 E. Lemon St. Lakeland, FL 33801-5079	
Orlando Utilities Commission	Curtis H. Stanton Energy Center	Frederick F. Haddad 500 S. Orange Ave. P.O. Box 3193 Orlando, FL 32801	
Progress Energy Florida, Inc.	Crystal River Power Plant	Bernie M. Cumbie 15760 W. Powerline St. Mail Code CN-77 Crystal River, FL 34428-6708	J. Michael Kennedy P.O. Box 14042 Mail Code CX1B St. Petersburg, FL 33733
Seminole Electric Cooperative	Seminole Generating Station	Michael P. Opalinski P.O. Box 272000 Tampa, FL 33688-2000	
Tampa Electric Company	Big Bend Station	Karen A. Sheffield Big Bend Station P.O. Box 111 Tampa, FL 33601-0111	Byron T. Burrows Tampa Electric Company, P4 P.O. Box 111 Tampa, FL 33601-0111
Tampa Electric Company	Gannon Station	Wade A. Maye 3602 Port Sutton Rd. P.O. Box 111 Tampa, FL 33601-0111	
Tampa Electric Company	Polk Power Station	Mark J. Hornick P.O. Box 111 Tampa, FL 33601-0111	

Others

Rebecca Robinette, Office of General Counsel, Department of Environmental Protection
DEP District Air Program Administrators
Local Air Pollution Control Program Administrators

Mississippi's Adoption of CAMR

SECTION 8. PROVISIONS FOR HAZARDOUS AIR POLLUTANTS

4. Mercury Emissions from Electric Utilities.
Mercury emissions from electric utilities are regulated in accordance with the Emission Guidelines for the Control of Mercury Emissions from Coal-Fired Electric Steam Generating Units promulgated by the U.S. Environmental Protection Agency in 40 CFR Part 60, Subpart HHHH, pursuant to Section 111 of the Federal Clean Air Act, as amended. All such regulations duly promulgated by the U.S. Environmental Protection Agency as of September 15, 2006, are incorporated herein and adopted by reference by the Commission as official regulations of the State of Mississippi and shall hereafter be enforceable as such, except for the changes noted in (a) and (b). Hereafter, any facility subject to the Federal Emission Guidelines shall comply with all applicable requirements of the regulation.

APPENDIX F

Federal CAVR

Federal Register

Wednesday,

July 6, 2005

Part III

Environmental Protection Agency

40 CFR Part 51

Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule

02

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 51

[FRL–7925–9]

RIN 2060–AJ31

Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: On July 1, 1999, EPA promulgated regulations to address regional haze (64 FR 35714). These regulations were challenged, and on May 24, 2002, the U.S. Court of Appeals for the District of Columbia Circuit issued a ruling vacating the regional haze rule in part and sustaining it in part. *American Corn Growers Ass'n* v. *EPA*, 291 F.3d 1 (D.C. Cir. 2002). Today's rule addresses the court's ruling in that case.

In addition, prior to the court's decision, EPA had proposed guidelines for implementation of the Best Available Retrofit Technology (BART) requirements under the regional haze rule, (66 FR 38108, July 20, 2001). The proposed guidelines were intended to clarify the requirements of the regional haze rule's BART provisions. We proposed to add the guidelines and also proposed to add regulatory text requiring that these guidelines be used for addressing BART determinations under the regional haze rule. In addition, we proposed one revision to guidelines issued in 1980 for facilities contributing to "reasonably attributable" visibility impairment.

In the *American Corn Growers* case, the court vacated and remanded the BART provisions of the regional haze rule. In response to the court's ruling, on May 5, 2004 we proposed new BART provisions and reproposed the BART guidelines. The *American Corn Growers* court also remanded to the Agency its decision to extend the deadline for the submittal of regional haze plans. Subsequently, Congress amended the deadlines for regional haze plans (Consolidated Appropriations Act for Fiscal Year 2004, Public Law 108–199, January 23, 2004). The May 5, 2004 proposed rule also contained an amendment to the regional haze rule to conform to the new statutory deadlines.

We received numerous comments on both the July 20, 2001 proposal and the May 5, 2004 reproposal. Today's final rule reflects our review of the public comments.

DATES: The regulatory amendments announced herein take effect on September 6, 2005.

ADDRESSES: Docket. 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.*, 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 OAR Docket, EPA/DC, EPA West, Room B102, 1301 Constitution Ave., 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 OAR Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Kathy Kaufman at (919) 541–0102 or by e-mail at *Kaufman.Kathy@epa.gov* or Todd Hawes at 919–541–5591 or by e-mail *Hawes.Todd@epa.gov.*

SUPPLEMENTARY INFORMATION:

Regulated Entities. This final rule will affect the following: State and local permitting authorities and Indian Tribes containing major stationary sources of pollution affecting visibility in federally protected scenic areas.

This list is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. This list gives examples of the types of entities EPA is now aware could potentially be regulated by this action. Other types of entities not listed could also be affected. To determine whether your facility, company, business, organization, etc., is regulated by this action, you should examine the applicability criteria in Part II of this preamble. If you have any questions regarding the applicability of this action to a particular entity, consult the people listed in the preceding section.

Outline. The contents of today's preamble are listed in the following outline.

I. Overview of Today's Actions

Today's rulemaking provides the following changes to the regional haze regulations:

(1) Revised regulatory text in response to the *American Corn Growers* court's remand, to require that the BART determination include an analysis of the degree of visibility improvement resulting from the use of control technology at each source subject to BART,

(2) Revised regulatory text in 40 CFR 51.308(b) and deletion of 40 CFR 51.308(c) *Options for regional planning* in response to Congressional legislation amending the deadlines for submittal of regional haze implementation plans. This provision had provided for an alternative process for States to submit regional haze implementation plans in attainment areas,

(3) BART guidelines, contained in a new Appendix Y to 40 CFR part 51,

(4) New and revised regulatory text, to be added to 40 CFR 51.308(e), regarding the use of Appendix Y in establishing BART emission limits, and

(5) Revised regulatory language at 40 CFR 51.302 to clarify the relationship between New Source Performance Standards (NSPS) and BART for reasonably attributable visibility impairment.

How This Preamble Is Structured. Section II provides background on the

Clean Air Act (CAA) BART requirements as codified in the regional haze rule, on the D.C. Circuit Court decision which remanded parts of the rule, and on the April 2004 reproposal responding to the remand. Section III discusses specific issues in the BART guidelines in more detail, including background on each issue, major comments we received on the July 2001 proposal and May 2004 reproposal, and our responses to those comments. Section IV provides a discussion of how this rulemaking complies with the requirements of Statutory and Executive Order Reviews.

II. Background

A. The Regional Haze Rule

In 1999, we published a final rule to address a type of visibility impairment known as regional haze (64 FR 35714, July 1, 1999). The regional haze rule requires States to submit implementation plans (SIPs) to address regional haze visibility impairment in 156 Federally-protected parks and wilderness areas. These 156 scenic areas are called "mandatory Class I Federal areas" in the Clean Air Act (CAA)[1] but are referred to simply as "Class I areas" in today's rulemaking. The 1999 rule was issued to fulfill a long-standing EPA commitment to address regional haze under the authority and requirements of sections 169A and 169B of the CAA.

As required by the CAA, we included in the final regional haze rule a requirement for BART for certain large stationary sources that were put in place between 1962 and 1977. We discussed these requirements in detail in the preamble to the final rule (64 FR at 35737–35743). The regulatory requirements for BART were codified at 40 CFR 51.308(e) and in definitions that appear in 40 CFR 51.301.

The CAA, in sections 169A(b)(2)(A) and in 169A(g)(7), uses the term "major stationary source" to describe those sources that are the focus of the BART requirement. To avoid confusion with other CAA requirements which also use the term "major stationary source" to refer to a somewhat different population of sources, the regional haze rule uses the term "BART-eligible source" to describe these sources. The BART-eligible sources are those sources which have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were put in place between August 7, 1962 and August 7, 1977, and whose operations fall within one or more of 26 specifically listed source categories. Under the CAA, BART is required for any BART-eligible source which a State determines "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area." Accordingly, for stationary sources meeting these criteria, States must address the BART requirement when they develop their regional haze SIPs.

Section 169A(g)(7) of the CAA requires that States must consider the following factors in making BART determinations:

(1) The costs of compliance,

(2) The energy and nonair quality environmental impacts of compliance,

(3) Any existing pollution control technology in use at the source,

(4) The remaining useful life of the source, and

(5) The degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

These statutory factors for BART were codified at 40 CFR 51.308(e)(1)(ii).

In the preamble to the regional haze rule, we committed to issuing further guidelines to clarify the requirements of the BART provision. The purpose of this rulemaking is to fulfill this commitment by providing guidelines to assist States as they identify which of their BART-eligible sources should undergo a BART analysis (*i.e.*, which are "sources subject to BART") and select controls in light of the statutory factors listed above ("the BART determination").

B. Partial Remand of the Regional Haze Rule in American Corn Growers v. EPA

In response to challenges to the regional haze rule by various petitioners, the D.C. Circuit in American Corn Growers[2] issued a ruling striking down the regional haze rule in part and upholding it in part. This section discusses the court's opinion in that case as background for the discussion of specific changes to the regional haze rule and the BART guidelines presented in the next two sections, respectively.

We explained in the preamble to the 1999 regional haze rule that the BART requirements in section 169A(b)(2)(A) of the CAA demonstrate Congress' intent to focus attention directly on the problem of pollution from a specific set of existing sources (64 FR 35737). The CAA requires that any of these existing sources "which, as determined by the State, emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility [in a Class I area]," shall install the best available retrofit technology for controlling emissions.[3] In determining BART, the CAA requires the State to consider several factors that are set forth in section 169(g)(2) of the CAA, including the degree of improvement in visibility which may reasonably result from the use of such technology.

The regional haze rule addresses visibility impairment resulting from emissions from a multitude of sources located across a wide geographic area. Because the problem of regional haze is caused in large part by the long-range transport of emissions from multiple sources, and for certain technical and other reasons explained in that rulemaking, we had adopted an approach that required States to look at the contribution of all BART sources to the problem of regional haze in determining both applicability and the appropriate level of control. Specifically, we had concluded that if a source potentially subject to BART is located within an upwind area from which pollutants may be transported downwind to a Class I area, that source "may reasonably be anticipated to cause or contribute" to visibility impairment in the Class I area. Similarly, we had also concluded that in weighing the factors set forth in the statute for determining BART, the States should consider the collective impact of BART sources on visibility. In particular, in considering the degree of visibility improvement that could reasonably be anticipated to result from the use of such technology, we stated that the State should consider the degree of improvement in visibility that would result from the cumulative impact of applying controls to all sources subject to BART. We had concluded that the States should use this analysis to determine the appropriate BART emission limitations for specific sources.[4]

In *American Corn Growers* v. *EPA*, industry petitioners challenged EPA's interpretation of both these aspects of the BART determination process and raised other challenges to the rule. The court in *American Corn Growers* concluded that the BART provisions in the 1999 regional haze rule were inconsistent with the provisions in the CAA "giving the states broad authority over BART determinations." 291 F.3d at 8. Specifically, with respect to the test for determining whether a source is subject to BART, the court held that the

[1] See, e.g. CAA Section 169A(a)(1).

[2] *American Corn Growers et al.* v. *EPA*, 291 F.3d 1 (2002).

[3] CAA sections 169A(b)(2) and (g)(7).

[4] *See* 66 FR at 35737–35743 for a discussion of the rationale for the BART requirements in the 1999 regional haze rule.

method that EPA had prescribed for determining which eligible sources are subject to BART illegally constrained the authority Congress had conferred on the States. *Id.* The court did not decide whether the general collective contribution approach to determining BART applicability was necessarily inconsistent with the CAA. *Id.* at 9. Rather, the court stated that "[i]f the [regional haze rule] contained some kind of a mechanism by which a state could exempt a BART-eligible source on the basis of an individualized contribution determination, then perhaps the plain meaning of the Act would not be violated. But the [regional haze rule] contains no such mechanism." *Id.* at 12.

The court in *American Corn Growers* also found that our interpretation of the CAA requiring the States to consider the degree of improvement in visibility that would result from the cumulative impact of applying controls in determining BART was inconsistent with the language of the Act. 291 F.3d at 8. Based on its review of the statute, the court concluded that the five statutory factors in section 169A(g)(2) "were meant to be considered together by the states." *Id.* at 6.

C. Changes in Response to American Corn Growers

Today's rule responds to the *American Corn Growers* court's decision on the BART provisions by including changes to the regional haze rule at 40 CFR 51.308, and by finalizing changes to the BART guidelines. This section outlines the changes to the regional haze rule due to the court's remand. It also explains the minor change we are making to the section of the regulation governing the use of the 1980 BART guidelines when conducting BART analyses for certain power plants for reasonably attributable (*i.e.,* localized) visibility impairment.

1. Determination of Which Sources Are Subject to BART

Today's action addresses the *American Corn Growers* court's vacature of the requirement in the regional haze rule requiring States to assess visibility impacts on a cumulative basis in determining which sources are subject to BART. Because this requirement was found only in the preamble to the 1999 regional haze rule (see 291 F.3d at 6, citing 64 FR 35741), no changes to the regulations are required. Instead, this issue is addressed in the BART guidelines, which provide States with appropriate techniques and methods for determining which BART-eligible sources "may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area." These processes, to address the holding of *American Corn Growers* by eliminating the previous constraint on State discretion, are explained in further detail in sections II.D. and III below.

2. Consideration of Anticipated Visibility Improvements in BART Determinations

Pursuant to the remand in *American Corn Growers,* we are amending the regional haze rule to require the States to consider the degree of visibility improvement resulting from a source's installation and operation of retrofit technology, along with the other statutory factors set out in CAA section 169A(g)(2), when making a BART determination. This has been accomplished by listing the visibility improvement factor with the other statutory BART determination factors in 40 CFR 51.308(e)(1)(A), so that States will be required to consider all five factors, including visibility impacts, on an individual source basis when making each individual source BART determination.

D. Center for Energy and Economic Development v. EPA

After the May 2004 reproposal of the BART guidelines, the D.C. Circuit decided another case where BART provisions were at issue, *Center for Energy and Economic Development* v. *EPA,* 398 F.3d 653, 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 court in *CEED* affirmed our interpretation of CAA section 169A(b)(2) as allowing for non-BART alternatives where those alternatives are demonstrated to make greater progress than BART. (*CEED,* slip. op. at 13). The court, however, took issue with provisions of the regional haze rule governing the methodology of that demonstration. Specifically, 40 CFR 51.308(e)(2) requires that visibility improvements under source-specific BART—the benchmark for comparison to the alternative program—be estimated based on the application of BART controls to all sources subject to BART. (This section was incorporated into the WRAP Annex rule by reference at 40 CFR 51.309(f)). The court held that we could not require this type of group BART approach—vacated in *American Corn Growers* in a source-specific BART context—even in a program in which State participation was wholly optional.

The BART guidelines as proposed in May 2004 contained a section offering guidance to States choosing to address their BART-eligible sources under the alternative strategy provided for in 40 CFR 51.308(e)(2). This guidance included criteria for demonstrating that the alternative program achieves greater progress towards eliminating visibility impairment than would BART.

In light of the D.C. Circuit's decision in *CEED,* we have not included the portion of the proposed BART guidelines addressing alternative programs in today's rulemaking. We remain committed to providing States with the flexibility to address BART through alternative means, and we note again that our authority to do so was upheld in *CEED.* Therefore, we intend to revise the provisions of the regional haze rule governing such alternatives and provide any additional guidance needed in a subsequent rulemaking conducted as expeditiously as practicable.

E. Relationship Between BART and the Clean Air Interstate Rule (CAIR)

On March 10, 2005, EPA issued the Clean Air Interstate Rule (CAIR), requiring reductions in emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_X) in 28 eastern States and the District of Columbia. When fully implemented, CAIR will reduce SO_2 emissions in these states by over 70 percent and NO_X emissions by over 60 percent from 2003 levels. The CAIR imposes specified emissions reduction requirements on each affected State, and establishes an EPA-administered cap and trade program for EGUs in which States may participate as a means to meet these requirements. The relationship between BART and the Clean Air Interstate Rule (CAIR) is discussed in section IV. below.

F. Overview of the BART Process

The process of establishing BART emission limitations can be logically broken down into three steps: First, States identify those sources which meet the definition of "BART-eligible source" set forth in 40 CFR 51.301. Second, States determine whether such sources "emit[] any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility [in a Class I area.]" A source which fits this description is "subject to BART." Third, for each source subject to BART, States then identify the appropriate type and the level of control for reducing emissions.

Identifying BART-eligible sources. The CAA defines BART-eligible sources as those sources which fall within one of 26 specific source categories, were built during the 15-year window of time from 1962 to 1977, and have potential emissions greater than 250 tons per year. The remand did not address the step of identifying BART-eligible sources, which is conceptually the simplest of the three steps.

Sources reasonably anticipated to cause or contribute to visibility impairment (sources subject to BART). As we noted in the preamble to the 1999 regional haze rule, defining the individual contributions of specific sources of the problem of regional haze can be time-consuming and expensive. Moreover, Congress established a very low threshold in the CAA for determining whether a source is subject to BART. We are accordingly finalizing several approaches for States for making the determination of whether a source "emits any pollutants which may reasonably be anticipated to cause or contribute to any visibility impairment." Certain of these approaches would allow States to avoid undertaking unnecessary and costly studies of an individual source's contribution to haze by allowing States to adopt more streamlined processes for determining whether, or which, BART-eligible sources are subject to BART.

In 1999, we adopted an applicability test that looked to the collective contribution of emissions from an area. In particular, we stated that if "a State should find that a BART-eligible source is 'reasonably anticipated to cause or contribute' to regional haze if it can be shown that the source emits pollutants within a geographic area from which pollutants can be emitted and transported downwind to a Class I area."[5] States certainly have the discretion to consider that all BART-eligible sources within the State are "reasonably anticipated to cause or contribute" to some degree of visibility impairment in a Class I area.

This is consistent with the *American Corn Growers* court's decision. As previously noted, the court's concern with our original approach governing BART applicability determinations was that it would have "tie[d] the states' hands and force[d] them to require BART controls at sources without any empirical evidence of the particular source's contribution to visibility impairment." 291 F.3d at 8. By the same rationale, we believe it would be an impermissible constraint of State authority for the EPA to force States to conduct individualized analyses in order to determine that a BART-eligible source "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any [Class I] area."[6] *American Corn Growers* did not decide whether consideration of visibility impact on a cumulative basis would be invalid in all circumstances. 291 F.3d at 9. Given the court's emphasis on the importance of the role of the States in making BART determinations, we believe that a State's decision to use a cumulative analysis at the eligibility stage is consistent with the CAA and the findings of the D.C. Circuit.

We believe a State may conclude that all BART-eligible sources within the State are subject to BART.[7] Any potential for inequity towards sources could be addressed at the BART determination stage, which contains an individualized consideration of a source's contribution in establishing BART emission limits.

States also have the option of performing an analysis to show that the full group of BART-eligible sources in a State cumulatively may not be reasonably anticipated to cause or contribute to any visibility impairment in Class I areas. We anticipate that in most, if not all States, the BART-eligible sources are likely to cause or contribute to some visibility impairment in Class I areas. However, it is possible that using a cumulative approach, a State could show that its BART sources do not pose a problem.

Finally, States may consider the individualized contribution of a BART-eligible source to determine whether a specific source is subject to BART. Specifically, States may choose to undertake an analysis of each BART-eligible source in the State in considering whether each such source meets the test set forth in the CAA of "emit[ting] any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any [Class I] area." Alternatively, States may choose to presume that all BART-eligible sources within the State meet this applicability test, but provide sources with the ability to demonstrate on a case by case basis that this is not the case. Either approach appears consistent with the D.C. Circuit's statement that a collective contribution approach may be appropriate so long as the States are allowed to exempt sources on the basis of an individualized contribution determination. 291 F.3d at 8.

Today's guidelines include different options States can use to assess whether source should be subject to BART. States need to determine whether to make BART determinations for all of their BART-eligible sources, or to consider exempting some of them from BART because they may not reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. For assessing the impact of BART-eligible sources on nearby Class I areas, we are including a process whereby the States would use an air quality model able to estimate a single source's contribution to visibility impairment and a different process whereby States could exempt groups of sources with common characteristics based on representative model plant analyses. Finally, States may use cumulative modeling to show that no sources in a State are subject to BART.

The BART determination. The State must determine the appropriate level of BART control for each source subject to BART. Section 169A(g)(7) of the CAA requires States to consider the following factors in making BART determinations: (1) The costs of compliance, (2) the energy and nonair quality environmental impacts of compliance, (3) any existing pollution control technology in use at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. The remand did not address the first four steps of the BART determination. The remand did address the final step, mandating that we must permit States to take into account the degree of improvement in visibility that would result from imposition of BART on each individual source when deciding on particular controls.

The first four factors are somewhat similar to the engineering analysis in the original BART guidelines proposed in 2001 and reproposed in 2004. The BART guidelines also contains a detailed discussion of available and cost-effective controls for reducing SO_2 and NO_X emissions from large coal-fired electric generating units (EGUs).

For assessing the fifth factor, the degree of improvement in visibility from various BART control options, the States may run CALPUFF or another appropriate dispersion model to predict visibility impacts. Scenarios would be

[5] 64 FR 335740, July 1, 1999. The regional haze rule discusses at length why we believe that States should draw this conclusion. 64 FR at 35739–35740.

[6] CAA section 169A(b)(2)(A).

[7] See 64 FR at 35714, 35721; see also *Supporting Information for Proposed Applicability of Regional Haze Regulations*, Memorandum by Rich Damberg to Docket A–95–38, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, July 29, 1997.

run for the pre-controlled and post-controlled emission rates for each of the BART control options under review. The maximum 24-hour emission rates would be modeled for a period of three or five years of meteorological data. States have the flexibility to develop their own methods to evaluate model results.

III. Detailed Discussion of the Final BART Guidelines

A. Introduction

In this section of the preamble, we discuss changes or clarifications to the reproposed BART guidelines. Where relevant, we also respond to comments received during the comment period on the 2001 proposal. For each provision of the guidelines that we are changing or clarifying, we provide discussion of, as appropriate:

—Background information,
—How the provision was addressed in the May 2004 reproposal (and in the 2001 proposal, if different from the reproposal),
—A summary of comments received on the provision, either from the May 2004 reproposal, from the July 2001 proposal, or from both, and
—The changes or clarifications that we are finalizing and the reasons for these changes or clarifications.

B. Scope of the Rule—Whether To Require States To Follow the Guidelines for All BART Sources

Background. Section 169A(b)(1) of the CAA requires EPA to issue regulations to provide guidelines to States on the implementation of the visibility program. In addition, the last sentence of section 169A(b) states:

> In the case of a fossil-fuel fired generating powerplant having a capacity in excess of 750 megawatts, the emission limitations required under this paragraph shall be determined pursuant to guidelines, promulgated by the Administrator under paragraph (1).

This statutory requirement clearly requires us to promulgate BART guidelines that the States must follow in establishing BART emission limitations for power plants with a total capacity exceeding the 750 megawatt cutoff. The statute is less clear regarding the import of the guidelines for sources other than 750 megawatt power plants.

Proposed rules. Both the 2001 proposal and the 2004 reproposal included a requirement for States to follow the procedures set out in the guidelines in determining BART for sources in all of the 26 listed BART categories. The 2001 proposal requested comment on whether the regional haze rule should: (1) Require the use of the guidelines only for 750 megawatt utilities, with the guidelines applying as guidance for the remaining categories, or (2) require the use of the guidelines for all of the affected source categories.

Comments. We received comments on this issue in both 2001 and 2004. Comments varied widely on whether we can or should require the use of the guidelines for all of the affected source categories.

Comments from State, local and tribal air quality agencies generally supported our proposal to require the use of the guidelines for all of the source categories. These comments cited a need for national consistency in the application of the BART requirement across the source categories, and from State to State. One State agency commenter questioned our legal authority to require the use of the guidelines for all source categories; and several State agency commenters, while supporting the proposal, requested that we provide clarification of the legal authority for requiring the States to use the guidelines in establishing BART emission limitations for all categories.

Comments from the utility industry, from various manufacturing trade groups, and from individual companies were critical of the proposal to require States to follow the guidelines generally. Many commenters also argued that EPA lacked the authority to issue guidelines for any industrial category other than 750 megawatt powerplants, whether the use of such guidelines were mandatory or not. Other commenters stated that the language in the CAA clearly restricts the scope of mandatory guidelines to larger powerplants. The commenters cited the legislative history of the 1977 Clean Air Act amendments in support of this position, and frequently claimed that requiring the guidelines for all 26 categories of sources would deprive States of flexibility in implementing the program.

Comments from environmental organizations and the general public supported the approach in the proposed rule and stated that EPA is obligated to establish regional haze BART guidelines by rulemaking for all 26 categories of stationary sources. Environmental organization comments noted that while Congress expressed a particular concern for 750 MW powerplants, this added emphasis on one sector does not change requirements in the Act for all BART-eligible sources. Accordingly, these commenters believed that we should not construe a special emphasis on powerplants as a restriction on our authority to require use of the guidelines for all categories.

Final rule. The CAA and the relevant legislative history make clear that EPA has the authority and obligation to publish mandatory guidelines for powerplants exceeding 750 megawatts. As previously noted, Congress in section 169A(b) of the CAA expressly provided that emission limitations for powerplants larger than 750 megawatts "*shall be determined* pursuant to guidelines promulgated by the Administrator." (Emphasis added). This unambiguous language leaves little room to dispute that the guidelines EPA is required to promulgate must be used by States when making BART determinations for this class of sources.

Having carefully considered the comments and further reviewed the CAA and the legislative history, we have concluded that it would not be appropriate for EPA to require States to use the guidelines in making BART determinations for other categories of sources. The better reading of the Act indicates that Congress intended the guidelines to be mandatory only with respect to 750 megawatt powerplants. Thus, while we acknowledge the State agency comments and the policy reasons support consistency across States, we are not requiring States to use the BART guideline for these other categories. In response to State concerns about equitable application of the BART requirement to source owners with similar sources in different States, we do encourage States to follow the guidelines for all source categories but are not requiring States to do so. States should view the guidelines as helpful guidance for these other categories.

We disagree with comments that the CAA and the legislative history prohibit us from issuing guidance for other source categories. As the guidelines make clear, States are not required to follow the approach in the guidelines for sources other than 750 megawatt powerplants. As such, although we believe that the guidelines provide useful advice in implementing the BART provisions of the regional haze rule, we do not believe that they hamper State discretion in making BART determinations.

C. How To Identify BART-Eligible Sources

Section II of the BART guidelines contains a step-by-step process for identifying stiationary sources that are "BART-eligible" under the definitions in the regional haze rule. The four basic steps are:

Step 1: Identify the emission units in the BART categories.

Step 2: Identify the start-up dates of those emission units.

Step 3: Compare the potential emissions from units identified in Steps 1 and 2 to the 250 ton/year cutoff.

Step 4: Identify the emission units and pollutants that constitute the BART-eligible source.

In this section of the preamble, we discuss some of the comments we received on the steps in this process, and any changes we are making in light of those comments.

Step 1: Identify the Emission Units in the BART Categories

The BART guidelines list the 26 source categories that the CAA uses to describe the types of stationary sources that are BART-eligible. Both proposals clarified the descriptions of particular source categories.

Comments. The final rule addresses comments on the following source categories. Some comments discussed below were submitted in response to the 2001 propoosal and were not addressed in the reproposal; other comments were submitted in response to the reproposal in 2004.

(1) "Charcoal production facilities." We received comments in 2001 from two industry trade groups requesting that the final guidelines explicitly exclude "low-emission" charcoal production facilities from BART. These comments cited a 1975 study considered by Congress in development of the BART category list in the 1977 CAA amendments. This 1975 study noted that some charcoal production facilities have much higher emissions factors (i.e., 352 pounds of PM per ton of charcoal produced versus 20 to 25 pounds of PM per ton of charcoal produced). Accordingly, the comments asserted that the intent of Congress in the 1977 CAA amendments was to provide incentives for higher-emitting facilities to reduce their emissions, rather than to make the entire category BART-eligible.

(2) "Chemical process plants." In 2001 a trade group representing the pharmaceutical industry requested that we determine in the guidelines that the term "chemical process plants" does not include pharmaceutical plants.

(3) "Primary aluminum ore reduction." Comments from the aluminum industry in 2001 noted that not all emissions units at these facilities are necessarily involved in "primary ore reduction." Thus, the comments recommended that we clarify that contiguous sources that are not related to primary aluminum ore reduction, such as fabricating facilities and ingot operations, are not BART-eligible. Further, the comments recommended that we use definitions in the NSPS for primary aluminum plants to describe the BART-eligible emissions units.

(4) "Fossil-fuel fired steam electric plants of more than 250 million Btu/hour heat input." The 2004 reproposal contained the clarification, requested by commenters, that this source category refers only to those fossil-fuel fired steam electric plants that generate electricity for sale. One commenter objected to this clarification on the basis that emissions from co-generators would be excluded; many other commenters supported the clarification. Another commenter requested that we also clarify that this category includes only those steam electric plants that burn greater than 50 percent fossil fuel, in order to be consistent with the definition of fossil-fuel boilers proposed in the guidelines. Other commenters requested that we clarify whether the definition includes units which are located at a steam electric plant, but which themselves are not in any of the 26 BART source categories, such as simple cycle turbines, emergency diesel engines, and reciprocating internal combustion engines (RICE).

Several commenters opined that the category should exclude combined cycle units with heat recovery steam generators that lack auxiliary firing, arguing that these units should count as simple cycle turbines. These commenters pointed to other EPA regulatory programs that treat combined cycle units with supplemental firing differently from combined cycle units without supplemental firing. They argued that we should only consider a combined cycle unit to be a "steam electric plant" if it has supplemental firing.

(5) "Fossil-fuel boilers of more than 250 million Btu/hour heat input." The 2004 reproposal clarified that this category should be read as including only those boilers individually greater than 250 million Btu/hour heat input. We received many comments on this interpretation, both in favor and opposed. Those favoring this interpretation (generally industry commenters) cited the implementation burden that including smaller boilers would pose, the high cost-effectiveness of controlling smaller boilers, and the relatively smaller impact on regional haze that smaller boilers would pose. They also noted that this interpretation is most consistent with definitions in the NO_X SIP call and new source performance standards (NSPS).

Commenters opposing this interpretation (environmental groups, one state, and one regional planning organization) noted that regarding all boilers, irrespective of size, as BART-eligible so long as the aggregate heat input exceeds 250 million Btu/hour is more consistent with the definition of stationary source under the Prevention of Significant Deterioration (PSD) program. These commenters noted that under the CAA, BART and PSD are complementary programs aimed at regulating the same source categories; either one or the other applies depending upon when the source was constructed.

The 2004 reproposal also clarified that if a boiler smaller than 250 million Btu/hour heat input is an integral part of an industrial process in a BART source category other than electric utilities, then the boiler should be considered part of the BART-eligible source in that category. Under these circumstances, the boiler, as part of the BART-eligible source, should be considered for emission control. Some commenters opposed this interpretation, asserting that it would result in an "arbitrary and capricious" inconsistency, in that some smaller boilers would be BART-eligible, and others would not. These commenters also noted that these boilers could be included in regional haze SIPs as necessary for making "reasonable progress" toward CAA visibility goals, even if they are not considered to be BART-eligible.

Final rule. After considering the comments, we have made the following determinations on the definitions of the following source categories:

(1) "Charcoal production facilities." We believe that in using the term "charcoal production facilities" Congress intended to encompass all types of charcoal production facilities. We do not agree with comments that any inferences can necessarily be made regarding the presence of different PM emission factors for different types of charcoal production facilities in the 1975 report. For example, if Congress only intended to regulate a subset of the charcoal production industry, then we believe Congress could have easily indicated this in the source category title, as was done for "kraft pulp mills" and for "coal cleaning plants (thermal dryers)." We also note that it is more likely that plants in the charcoal production industry with lower emission factors have emissions that are less than the 250 tons per year cutoff for BART eligibility.

(2) "Chemical process plants." We believe that there is a clear precedent to include pharmaceutical manufacturing operations as "chemical process plants." In the standard industrial classification (SIC) system, pharmaceutical operations are generally

in SIC codes 2833 and 2834, which are a subset of 2-digit category 28 "Chemical and Allied products." Similarly, in the new North American Industrial Classification Codes (NAICS), pharmaceutical manufacturing is codes 32541 and 32542, which is a subset of the "chemical manufacturing subsector" which is code 325. Accordingly, in the PSD program, pharmaceutical plants have been treated as "chemical process plants." The commenter is correct in noting that EPA has consistently distinguished between chemical manufacturing and pharmaceutical manufacturing. Examples where different standards or guidelines are established included control technique guideline (CTG) documents, NSPS standards under section 111 of the CAA, and, most recently, maximum achievable control technology (MACT) standards under section 112 of the CAA. We do not agree that these differentiations for emissions standards necessarily require differentiation for purposes of determining BART eligibility. Therefore we believe pharmaceuticals should not be excluded from BART. However, we expect that because of the MACT standards, there is a very low probability that BART determinations will lead to further control requirements from chemical production processes at pharmaceutical plants.

(3) "Primary aluminum ore reduction." We agree with commenters that BART-eligible units in this source category should be defined consistently with the NSPS definition for primary aluminum ore reduction. Therefore we have added a clarification to that effect in the final BART guidelines. We note that this definition is also consistent with the definition at 40 CFR 63.840, which establishes applicability for this source category for the MACT program.

(4) "Fossil-fuel fired steam electric plants of more than 250 million Btu/hour heat input." We have retained the clarification that this source category refers only to those fossil-fuel fired steam electric plants that generate electricity for sale. We believe that this clarification helps to distinguish those plants that are electric utilities from plants in other industrial categories. We also believe that while large co-generators would be excluded from the fossil-fuel fired steam electric plant source category, most large co-generators will be BART-eligible under the fossil-fuel fired boilers source category.

We do not believe it makes sense for this category to include only those steam electric plants that burn greater than 50 percent fossil fuel. We do not believe that a boiler should be excluded from BART review simply because it is located at a plant which burns less than 50 percent fossil fuel. Emissions from any such boiler could be a significant contributor to regional haze, and as such, we believe that each fossil-fuel fired boiler merits a BART review.

We do wish to clarify that units which are located at a steam electric plant, but which themselves are not in any of the 26 BART source categories, should not be considered to be BART-eligible units. We believe that Congress intended that BART review be focused on units in the source categories it delineated. This interepretation is most consistent with the definition of BART-eligible source as we have explained it elsewhere in this preamble in reference to whether entire plants are included if only some units at the plant meet the statutory criteria.

Finally, we believe that all combined cycle units are included in the definition of fossil fuel fired steam electric plant, regardless of whether the combined cycle unit's heat recovery steam generator lacks auxilliary firing. Commenters are correct that some EPA programs have treated combined cycle units with supplemental firing differently from combined cycle units without supplemental firing. However, while some EPA programs do not consider a unit to be a combined cycle unit unless it contains supplemental firing, the definition at issue here is the definition of fossil-fuel fired steam electric plant, not fossil-fuel fired unit. The CAA defines both "stationary source" (for visibility purposes) and "major emitting facility" (for PSD purposes) to include "fossil fuel fired steam electric plants." In previous guidance for PSD, we have explained that combined cycle gas turbines do fall within the category of "fossil-fuel fired steam electric plants." [8]

(5) "Fossil-fuel boilers of more than 250 million Btu/hour heat input." We have decided to retain the interpretation that this category should be read as including only those boilers individually greater than 250 million Btu/hour heat input. We agree with commenters who noted that including smaller boilers would pose considerable implementation burden. As noted in the 2004 reproposal notice, we do not believe that this interpretation is likely to have a substantial impact. Because smaller boilers are generally less cost-effective to control, we believe that BART review would be unlikely to result in a significant amount of control on these boilers.

We are also retaining the clarification that if a boiler smaller than 250 million Btu/hour heat input is an integral part of an industrial process in a BART source category other than electric utilities, then the boiler should be considered part of the BART-eligible source in that category. (By "integral to the process", we mean that the process uses any by-product of the boiler, or vice-versa. We have added this clarification to the definition in the BART guidelines.) We believe that if a State is already considering a BART-eligible industrial process for control, and a boiler is integrated into that process, it makes common sense not to prematurely rule out control options any of the emissions from that process as a whole. (Note that a boiler which is not integral, but is simply attached to a plant, should not be included.) For example, Kraft pulp mills may have boilers that are not serving the energy infrastructure of the plant but typically are serving a process directly by using the waste liquor from the process. Including such a boiler in consideration of control options for the process adds minimal additional burden while leaving maximum discretion to the State in determining BART for the process as a whole.

We are also clarifying today that we have determined that this category should include all individual boilers of greater than 250 million Btu/hour heat input burning any amount of fossil fuel, as opposed to only those boilers that burn greater than 50 percent fossil fuel. We believe that it is quite possible that boilers of this size could contribute to regional haze in a Class I area even if they burn less than 50 percent fossil fuel. Therefore we believe that each fossil fuel-fired boiler merits a BART review.

Step 2: Identify the Start-up Dates of Those Emission Units

Background. BART applies only to a major stationary source which "was in existence on August 7, 1977 but which has not been in operation for more than fifteen years as of such date." The visibility regulations define "in existence" and "in operation" in 40 CFR 51.301. Under these regulations, promulgated in 1980, "in existence" means

> that the owner or operator has obtained all necessary preconstruction approvals or permits * * * and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations.

[8] See *http://www.epa.gov/Region7/programs/artrd/air/nsr/nsrmemos/turbines.pdf.*

The term "in operation" means engaged in activity related to the primary design function of the source.

Step 2 also addresses the treatment of "reconstructions" and "modifications." Under the definition of BART-eligible facility, sources which were in operation before 1962 but reconstructed during the 1962 to 1977 time period are treated as new sources as of the time of reconstruction.[9] The same policies and procedures for identifying reconstructed "affected facilities" under the NSPS are used to determine whether a source has been reconstructed for purposes of the BART requirements. "Modifications" under the CAA refers to physical change or change in the method of operation at a source which has led to an increase in emissions. In the proposed BART guidelines, we stated that the best interpretation of the visibility provisions is that a modification to a source does not change an emission's unit construction date for purposes of BART applicability. We requested comment on an alternative interpretation that we believed would be more difficult to implement. Under this approach, sources built before 1962 but modified during the 1962 to 1977 time frame would be considered "new" at the time of modification.

Comments. We received comments in 2001 and 2004 on the discussion in the guideline of the term "in existence." These comments were critical of our statement in the guidelines that sources which had "commenced construction," that is, those which had entered into binding contracts, would be considered to be in existence, even if actual operations did not begin until after the August 7, 1977 cutoff date. These commenters asserted that Congress did not intend to treat a source as "existing" in 1977 if it was not yet built.

Other commenters interpreted the proposed guidelines as expanding the definition of BART-eligible sources by requiring States to find that all emission units at a facility are BART-eligible if one part of the facility was built within the 1962–1977 time period. Other comments did not suggest that we had already expanded the definition in the proposed guidelines, but did suggest that we should expand the definition in that way in the final guidelines. Some commenters noted that there was a degree of confusion in the regulated community on whether the proposed guidelines were requiring BART for all units at a power plant, including those that were in operation before August 7, 1962, if these units are co-located with one or more units that were put in place within the 1962–1977 time period. These commenters requested that we clarify that such pre-1962 units would not be BART-eligible.

Some commenters asserted that our proposed approach is unworkable, because the approach requires States to identify all emissions units put in place between the 1962 and 1977. Some of these commenters asserted that Congress intended that BART would apply only if entire plants satisfy the statutory criteria. These comments suggested that BART should apply only if an entire plant that is one of the 26 listed source category types had been placed in operation at a discrete point within the 15 year time period for BART eligibility. These commenters asserted that our proposed guidelines, which involved the identification and aggregation of individual emission units within the 1962–1977 time period, were inconsistent with Congress' intent. Other comments suggested that EPA could improve implementation of the program by covering discrete projects rather than individual emissions units. A few commenters suggested that for purposes of identifying such discrete projects, we consider using the term "process or production unit" that we used in hazardous air pollutant regulations under CAA section 112(g).

One commenter requested that the guidelines clarify that emissions from "linked" emission units should not be considered in determining BART eligibility. That is, even if changes in emissions from one unit could affect the emissions from a "linked" unit that was not put in place within the 1962–1977 time period, that would not affect whether the "linked" unit was BART-eligible. Another commenter suggested that the approach set forth in the guidelines for identifying BART-eligible sources is inappropriate because the particular set of units identified as BART-eligible will not necessarily "provide a reasonable and logical platform for the installation of controls."

Other commenters stated that facilities that had been modified after 1977 should not be included in the pool of sources subject to BART. Such facilities, it was argued, already meet the BART requirements because of the controls installed to meet the requirements of PSD, NSR, or the NSPS.

Final rule. We disagree with the comments recommending that we interpret the term "in existence" to refer to sources that are in actual operation. The discussion of this term in Step 2 is based on the regulatory definition which has been in place since 1980. The guidelines reiterate this definition and provide examples of its application. Interpreting the term "in existence" as suggested by commenters would not be consistent with the plain language of the regulations.

In the 2001 and 2004 proposed guidelines, we noted that "the term 'in existence' means the same thing as the term 'commence construction' as that term is used in the PSD regulations." Commenters were critical of this statement, claiming that EPA was unlawfully reinterpreting section 169A in the guidelines. The statement in Step 2 of guidelines, however, is not a reinterpretation of the term "in existence," but merely a statement noting that the definitions used in the visibility regulations and the PSD regulations are essentially identical.

To the extent that commenters are claiming that the existing regulatory definition of "in existence" is unlawful, EPA's interpretation of this term in promulgating the 1980 regulations was a reasonable one. First, it is worth noting that the regulations adopting this interpretation of the term "in existence" were in effect in 1990 and implicitly endorsed by Congress in its 1990 amendments to the CAA.[10] Moreover, the definition at issue accurately reflects Congress' intent that the BART provision apply to sources which had been "grandfathered" from the new source review permit requirements in parts C and D of title I of the CAA. For all the above reasons, we are neither revising the regional haze regulations to change the definition of "in existence," nor adopting a strained interpretation of the regulation in the guidelines.

We agree with commenters that the definition of "BART-eligible source" does not require States to find that all emission units at a facility are subject to the requirement of the BART provisions if only one part of the facility was built within the 1962–1977 time period. We received comments on this issue in 2001 and clarified in 2004 that the BART guidelines do not direct States to find that all boilers at a facility are BART-eligible if one or more boilers at the facility were put in place during the relevant time period. Under Step 2 of the process for identifying BART-eligible sources set out in the guidelines, States are required to identify only those boilers that were put in place between 1962 and 1977. As explained in the preamble to the 2004 reproposed guidelines, only these boilers are potentially subject to BART.

[9] However, sources reconstructed after 1977, which reconstruction had gone through NSR/PSD permitting, are not BART-eligible.

[10] See CAA section 193.

We do not agree with those commenters claiming that Congress clearly intended to apply BART only if an "entire plant" was put into place between 1962 and 1977. Most of the BART source categories are broad descriptions types of industrial facilities such as "kraft pulp mills," "petroleum refineries" or "primary copper smelters." For such source categories, the implication of commenters' argument would that if any portion of the plant was in operation before August 7, 1962, then Congress intended to exempt the entire plant from BART. Such an interpretation is problematic and inequitable. For example, under this approach BART would not apply if a company chose to expand its production by building a second production line at an existing line in 1965, but would apply if the same company chose to build the same equipment at a greenfield site. Under the approach set forth in the guidelines, such a production line would be treated similarly under either set of facts. We do not believe that either the plain language of the statute or the relevant legislative history indicate that Congress intended for major-emitting sources of visibility-impairing pollutants to be exempted from the BART requirements because a plant contains some emission units that began operation before 1962.

Also, we disagree with the comment that modifications after 1977 should change an emissions' unit date of construction for purposes of BART applicability. The commenter's suggestion that such sources already meet BART requirements may be accurate, but does not provide a basis for exempting the source from review. As we note in the guideline, the review process will take into account the controls already in place and the State may find that these controls are consistent with BART.

We agree with the comments related to "linked" emission units. The comment appears to address whether emissions from the "linked" units are considered in determining BART eligibility. In the guidelines, we are focusing on only the emissions units that were put in place during the 1962 to 1977 dates and the emissions from those units. We agree that even if changes in emissions from one unit could affect the emissions from a "linked" unit that was not put in place within the 1962–1977 time period, this would not affect whether the "linked" unit was BART-eligible.

We disagree with commenters that the approach set forth in the guidelines for identifying BART-eligible sources is inappropriate because the particular set of units identified as BART-eligible will not necessarily "provide a reasonable and logical platform for the installation of controls." We do not agree that this factor is relevant to the identification of those emissions units which meet the definition of BART-eligible source. Such factors are important in the States' consideration of control strategies and options but do not clearly relate to the first step of identifying those sources which fall within one of 26 source categories, were built during the 15 year window of time from 1962 to 1977, and have potential emissions of greater than 250 tons per year. We do thus agree generally with the commenter's recommendation of allowing States to consider the particular history and control potential of units in determining BART, but do not agree that it is relevant to the predicate question of identifying the BART-eligible source.

Finally, the approach to identifying a "BART-eligible source" in the guidelines is based on the definitions in the regional haze rule of the relevant terms. For 750 MW power plants, States are required to apply the definitions as set forth in the guidelines; for other sources, States may adopt a different approach to the task of identifying BART-eligible sources, so long as that approach is consistent with the Act and the implementing regulations. In other words, while the guidelines adopt an approach for large power plants which involves the aggregation of all emissions units put into place between 1962 and 1977, States have the flexibility to consider other reasonable approaches to the question of identifying BART-eligible sources for other source categories.

For 750 MW power plants, many of the issues identified by commenters with the approach of looking at a facility on an emission unit by emission unit basis do not exist. Unlike many types of industrial processes, power plants consist generally of a discrete number of very large emission units. For other types of facilities such as kraft pulp mills or chemical process plants which may have many small emission units that have undergone numerous changes, the guidelines do not limit the ability of the States to approach the question of identifying BART-eligible sources in ways which make sense for the particular sources given their design and history.

Step 3: Compare the Potential Emissions to the 250 Ton/Yr Cutoff.

Background. Step 3 of the guidelines addresses the question of whether the units identified in Steps 1 and 2 have emissions in excess of the threshold for major sources set forth in section 169A(g)(7) of the CAA. The guidelines pose the following questions to help the States in determining whether the relevant emissions units have the potential to emit in excess of the 250 tons per year threshold of any single visibility-impairing pollutant:

(1) What pollutants should I address?

The 2001 proposed guidelines included the following list of visibility-impairing pollutants: SO_2, NO_X, particulate matter, volatile organic compounds (VOCs), and ammonia. We proposed in 2001 and again in 2004 that States use PM_{10} as the indicator for particulate matter. As explained in the guidelines, there is no need to have separate 250 ton thresholds for PM_{10} and $PM_{2.5}$ because emissions of PM_{10} include the components of $PM_{2.5}$ as a subset. In addition, because of various uncertainties associated with regulating VOCs and ammonia, we requested comment in 2004 on the level of discretion States should exercise in making BART determinations for VOCs and took ammonia off the list of visibility-impairing pollutants.

In both proposals, we clarified that the 250 tons per year cutoff applies to emissions on a pollutant by pollutant basis. In other words, a source is subject to BART only if it emits at least 250 tons per year of an individual visibility-impairing pollutant.

(2) What does the term "potential" emissions mean?

The proposed guidelines in 2001 and the reproposed guidelines in 2004 excerpt the definition of "potential to emit" from the regulations at 40 CFR 51.301. As the definition makes clear, the potential to emit of a source is calculated based on its capacity to emit a pollutant taking into account its physical and operational design. Under this definition, federally enforceable emission limits may be taken into account in calculating a source's potential emissions; however, emission limitations which are enforceable only by State and local agencies, but not by EPA and citizens in Federal court, cannot be used to limit a source's potential to emit for purposes of the regional haze program.

(3) What is a "stationary source?'

As explained above, States are required to make a BART determination only for "stationary sources" of a certain size that fall within one of 26 types of industrial categories listed in the statute and that were built within a certain time frame. The regional haze rule contains definitions that are relevant to the determination of the emissions units that comprise a "stationary source." First, the regulations at 40 CFR 51.301

define "stationary source" as "any building, structure, facility, or installation which emits or may emit any air pollutant." Second, the terms "building, structure, or facility" are defined in part based on grouping pollutant-emitting activities by industrial category:

Building, structure, or facility means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities must be considered as part of the same industrial grouping if they belong to the same Major Group (*i.e.*, which have the same two-digit code) as described in the Standard Industrial Classification Manual, 1972 as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101–0066 and 003–005–00176–0 respectively).

In the 2001 proposed guideline, we noted that support facilities, *i.e.* facilities used to convey, store, or otherwise assist in the production of the principal product, are considered to fall within the same industrial grouping as the primary facility. To clarify this, in 2004 we proposed to add language to the guideline noting that emission units at a plant, even if they are a "support facility" for purposes of other programs, would not be subject to BART unless they were within one of the 26 listed source categories and were built within the 1962 to 1977 time frame.

Discussion of "What Pollutants Should I Address?"

Comments. PM_{10} as an indicator. Some comments questioned the use of PM_{10} (which includes both coarse and fine particulate matter) as the indicator for particulate matter. Commenters noted that the coarse fraction, that is particulate matter between 10 and 2.5 micrograms in diameter, fundamentally differs compared to the fine mass in how it interacts with light. Commenters suggested that only the fine mass ($PM_{2.5}$) component of particulate matter is likely to contribute to visibility impairment. Accordingly, these commenters recommended that the 250 ton cutoff for particulate matter should be based upon emissions of $PM_{2.5}$.

Ammonia. Many commenters addressed the exclusion of ammonia from the list of visibility-impairing pollutants. A number of commenters, primarily from industry but also from one state and one regional planning organization, supported the exclusion of ammonia. These commenters generally cited the complexity and variability of ammonia's role in the formation of $PM_{2.5}$ in the atmosphere, the relative greater benefits of controlling NO_X and SO_2, the uncertainties in the inventory of ammonia emissions, and the inherent complexities of gauging the contribution of potential ammonia reductions to improving visibility in Class I areas. In addition, commenters noted that few, if any, point sources emit ammonia in amounts that exceed the 250 ton per year threshold.

Other commenters, including a number of environmental groups and several states, regional planning organizations, and industry commenters, argued that ammonia should be included in the list of visibility-impairing pollutants in the guidelines. In support of this view, commenters cited evidence that ammonia is a known precursor to $PM_{2.5}$. One commenter noted that improvements are being made to ammonia inventories and to the understanding of ammonia's role in the formation of haze. Other commenters pointed to a National Park Service (NPS) analysis of monitoring data that indicates that visibility-impairment due to nitrate aerosol formation (to which ammonia contributes) is of significant concern [11] and to a 2003 direction to policy-makers from the North American Research Strategy for Tropospheric Ozone (NARSTO) [12] indicating that consideration of control strategies needs to include ammonia in combination with other precursors to particle formation. Many commenters also argued that EPA should encourage or allow the States to consider ammonia in their visibility protection plans, and noted that ammonia reductions could be a cost-effective way to improve visibility under certain conditions.

Volatile Organic Compounds (VOCs). Several commenters responded to our request for comments on whether States should treat VOCs in urban areas differently from VOCs in rural areas. Environmental groups and a few States argued that the current state of scientific knowledge does not support a differentiation between urban and rural sources of VOCs. One environmental commenter cited evidence that organic aerosols are a major constituent of visibility-reducing aerosols and that VOCs are important precursors to the formation of secondary organic aerosols. One commenter also stated that VOCs may play a particularly significant role in particle formation in those rural areas with significant nearby sources of NO_X. Commenters also cited evidence that the contribution of VOC to particle formation likely varies widely in different areas of the country, and argued that States should retain flexibility to address local VOC sources if they determine that those sources are contributors of concern.

Several industry commenters stated that more focus should be placed on controlling VOCs in urban rather than rural areas. A few commenters from industry argued that VOCs in rural areas have not been shown to be a significant contributor to particle formation, and should be excluded from the list of pollutants to be addressed in the BART process. One argued that VOCs should be excluded from BART entirely based upon uncertainties in the current state of knowledge, and a few argued that VOCs from both power plants and rural sources should be excluded from BART, based on low emissions and the cost of controls. One regional planning organization requested that EPA clarify the definitions of "urban" and "rural" areas.

Final rule. PM_{10} as an indicator. While it is always necessary to assess $PM_{2.5}$ impacts, we agree with commenters who stated that the coarse fraction is less efficient at light scattering than fine particles, there is ample evidence that the coarse fraction does contribute to visibility impairment.[13] For example, standard methods for calculating reconstructed light extinction routinely include a calculation for the contribution to light extinction from the coarse fraction, an implicit recognition that these particles contribute measurably to visibility impairment.[14] We do recognize that coarse PM is likely to contribute more to regional haze in arid areas than humid areas. We believe that, as the Grand Canyon Visibility Transport Commission (GCTVC) recognized,[15] States in the arid West in particular should take the coarse fraction of particulate matter into account in determining whether a source meets the threshold for BART applicability.

Because long-range transport of fine particles is of particular concern in the formation of regional haze, we also

[11] See *http://wrapair.org/forums/ioc/meetings/030728/index.html* (specifically presentation by John Vimont, National Park Service).

[12] *NARSTO, Particulate Matter Assessment for Policy Makers: A NARSTO Assessment.* P. McMurry, M. Shepherd, and J. Vickery, eds. Cambridge University Press, Cambridge, England (2004).

[13] See *Fine particles: Overview of Atmospheric Chemistry, Sources of Emissions, and Ambient Monitoring Data,* Memorandum to Docket OAR 2002–0076, April 1, 2005.

[14] These methods are described at the following Web site: *http://vista.cira.colostate.edu/improve/Tools/ReconBext/reconBext.htm.*

[15] Grand Canyon Visibility Transport Commission, Recommendations for Improving Western Vistas, Report to the U.S. EPA, June 10, 1996.

believe that it is very important to estimate the $PM_{2.5}$ fraction of direct particulate emissions as correctly as possible. In addition, we believe that air quality modeling results will be more meaningful provide a more accurate prediction of a source's impact on visibility if the inputs account for the relative particle size of directly emitted particulate matter (e.g. PM_{10} vs. $PM_{2.5}$).

States should consider whether their current test methods for measuring particulate matter emissions from stationary sources account for the condensible fraction of particulate matter and consider revising any such stationary source test methods to account for the condensible fraction of particulate emissions. See the source testing technical support document (TSD) in the docket for this rule, which discusses test methods for particulate matter in more detail.[16]

Ammonia. In regard to ammonia, we believe there is sufficient uncertainty about emission inventories and about the potential efficacy of control measures from location to location such that the most appropriate approach for States to take is a case-by-case approach. There are scientific data illustrating that ammonia in the atmosphere can be a precursor to the formation of particles such as ammonium sulfate and ammonium nitrate;[17] however, it is less clear whether a reduction in ammonia emissions in a given location would result in a reduction in particles in the atmosphere and a concomitant improvement in visibility. In other words, the question of whether ammonia contribute to visibility impairment in a specific instance can be a difficult one.

It may be that States will not be faced often with the question of addressing ammonia in making BART determinations. As noted above, States are required to make BART determinations only for stationary sources that fall within certain industrial categories. The types of sources subject to the BART provisions are not typically significant emitters of ammonia. Because of this, it is unlikely that including ammonia on the list of visibility-impairing pollutants in the BART guidelines would have much impact on the States' determinations of whether a source is BART-eligible. Thus, while ammonia can contribute to visibility impairment, we believe the decision whether to consider ammonia as a visibility-impairing pollutant in a specific case where a potential BART source actually emits more than 250 tons per year of ammonia is best left to the State.

VOCs. Organic compounds can be categorized according to their varying degrees of volatility: highly reactive, volatile compounds with six or fewer carbon atoms which indirectly contribute to PM formation through the formation of oxidizing compounds such as the hydroxyl radical and ozone; semivolatile compounds with between seven and 24 carbon atoms which can exist in particle form and can readily be oxidized to form other low volatility compounds; and high molecular weight organic compounds—those with 25 carbon atoms or more and low vapor pressure—which are emitted directly as primary organic particles and exist primarily in the condensed phase at ambient temperatures. The latter organic compounds are considered to be primary $PM_{2.5}$ emissions and not VOCs for BART purposes.

Current scientific and technical information shows that carbonaceous material is a significant fraction of total $PM_{2.5}$ mass in most areas and that certain aromatic VOC emissions such as toluene, xylene, and trimethyl-benzene are precursors to the formation of secondary organic aerosol.[18] However, while progress has been made in understanding the role of VOCs in the formation of organic PM, this relationship remains complex, and issues such as the relative importance of biogenic versus anthropogenic emissions remain unresolved.

Therefore we believe that the best approach for States to follow in considering whether VOC emissions are precursors to $PM_{2.5}$ formation is a case-by-case approach. States should consider, in particular, whether a source's VOC emissions are those higher-carbon VOCs that are more likely to form secondary organic aerosols. In addition, given the variable contribution of a given amount of VOC emissions to $PM_{2.5}$ formation, States may also wish to exercise discretion in considering only relatively larger VOC sources to be BART-eligible.

After careful consideration of the comments, we agree with commenters who assert that EPA should not suggest a general distinction between the relative contributions of urban and rural VOC emissions to particle formation. The state of knowledge in this area is complex and rapidly evolving. Monitoring data in the East[19] suggest that there may be a greater contribution to particle formation in urban areas from VOCs as compared to rural areas, but we recognize that further research is needed to better determine the extent of the contribution of specific VOC compounds to organic PM mass. We do not agree, however, with commenters who make the blanket assertion that rural VOCs are not a significant contributor to particle formation, as it is possible that in specific areas, such as where NO_X emissions are high, rural anthropogenic VOCs could potentially play a significant role.

Discussion of the Term "Potential" Emissions

Comments. A number of commenters were critical of the restriction in the regional haze rule that allows States to credit federally enforceable limitations on emissions but not limitations that are enforceable only by States and local agencies. These commenters believed that this restriction had been rejected by the D.C. Circuit for a number of other EPA regulations and noted that EPA has developed policies that currently credit state-enforceable limits. The comments recommended that EPA issue guidance consistent with what commenters claimed were current policies for other regulations. In addition, we received comments arguing that in determining whether a source is a major stationary source, the States should consider a source's actual—rather than potential—emissions. These commenters stated that using a source's potential emissions overstates a source's actual emissions and impacts on visibility.

Final rule. CAA section 169A(g)(7) defines a "major stationary source" as a source with the potential to emit 250 tons or more any pollutant. Based *inter alia* on that statutory definition, EPA's implementing regulations define BART-eligible sources as those with the potential to emit 250 tons or more of any air pollutant. As these definitions clearly require consideration of a source's potential emissions, the guidelines state that a State should determine whether a source's potential emissions exceed the 250 ton threshold in determining whether the source is BART-eligible.

As explained in the 2001 and 2004 proposed guidelines, the regional haze regulations define "potential to emit." The guidelines repeat that regulatory definition and provide an example illustrating its application. EPA did not propose to change the definition in 2001 or 2004, but merely highlighted the

[16] *Fine particles: Overview of Source Testing Approaches,* Memorandum to Docket OAR 2002–0076, April 1, 2005.

[17] See *Fine particles: Overview of Atmospheric Chemistry, Sources of Emissions, and Ambient Monitoring Data,* Memorandum to Docket OAR 2002–0076, April 1, 2005.

[18] Ibid.

[19] Ibid.

current definition in 40 CFR 51.301. Although we noted in the 2001 proposed guidelines that we expected to undertake a rulemaking to determine whether only federally enforceable limitations should be taken into account in the regional haze program definition, we have not yet begun the process for such a rulemaking. However, we consider the comments criticizing EPA's definition of "potential to emit" as a request for reconsideration of the visibility regulations and will take these requests into account in determining any future rulemaking efforts to address the general definition of "potential to emit." For the time being, we believe that States may consider federally enforceable limits or emissions limitations in State permits, which are enforceable under State law, in determining a source's "potential to emit."

Discussion of What Emissions Units Should Be Considered Part of a "Stationary Source"

Comments. A number of comments in 2001 expressed concern with our statement that a "support facility" should be grouped with a primary facility in determining which emissions units belong to the same industrial grouping. These comments generally coincided with comments discussed above that EPA should determine BART on a plantwide basis, rather than by aggregating emissions units. Commenters on the 2004 reproposal noted with approval the clarification that "support facilities" should only be considered BART-eligible if these units themselves were both constructed within the 1962–1977 time frame and fell within one of the listed source categories.

Two commenters felt that we should more clearly define the BART-eligible source, either by identifying emission units within source categories, or by somehow accounting for the specific set of emission units, within the fenceline, to which controls would logically apply.

Final rule. The guidelines continue to note that the definition of "building, structure or facility" in the regional haze rule is based upon aggregating emissions units within the same industrial grouping. This discussion in the guidelines is consistent with the language in the definition of "building, structure or facility" in the regional haze rule which contains a specific reference to the 2-digit SIC classifications. The BART guidelines refer to this definition and explain how 2-digit SIC codes are used in determining the scope of BART for a given plantsite. (In the rare situation where industrial groupings in separate 2-digit SIC codes exist at a single plant site, then there would be more than one separate "stationary source" present. In that situation, each "stationary source" should be looked at individually for purposes of determining BART-eligibility.)

We agree that more clarity is needed to account for situations where a specific set of units constitute the logical set to which BART controls would apply. The CAA requires BART at certain major stationary sources. Accordingly we believe it could be appropriate, at the BART determination step, for States to allow sources to "average" emissions across a set of BART-eligible emission units within a fenceline, so long as the amount of emission reductions from each pollutant being controlled for BART would be at least equal to those reductions that would be obtained by simply controlling each unit. We have added language to the guidelines to this effect.

Step 4: Identify the Emission Units and Pollutants That Constitute the BART-Eligible Source

Background. The final step in identifying a "BART-eligible source" is to use the information from the previous three steps to identify the universe of equipment that makes up the BART-eligible source. The 2001 and 2004 proposed BART guidelines stated that if the emissions from the list of emissions units at a stationary source exceed a potential to emit of 250 tons per year for any individual visibility-impairing pollutant, then that collection of emissions units is a BART-eligible source. The guidelines also stated that a BART analysis would be required for each visibility-impairing pollutant emitted from this collection of emissions units.

In the 2004 reproposed BART guidelines, we noted that we believed that section 169A(b)(2)(A) of the CAA requires a State to undertake a BART analysis for "any" visibility-impairing pollutant emitted by a BART-eligible source, regardless of the amount emitted. We proposed, however, to provide the States with the flexibility to identify *de minimis* levels for pollutants at BART-eligible sources, but limited that flexibility so that any such *de minimis* levels could not be higher than those used in the PSD program: 40 tons per year for SO_2, NO_X, and VOC, and 15 tons per year from PM_{10}. We requested comment on this provision and on the use of *de minimis* values.

Discussion of Whether To Include All Emitted Visibility-Impairing Pollutants in the BART Analysis

Comments. A number of commenters supported the concept of including all pollutants in the BART analysis once an individual pollutant triggers the BART review. Other commenters, although supportive of the concept generally, recommended that we should add the pollutants together before the comparison with the threshold.

A number of commenters disagreed with EPA's conclusion that the CAA requires States to make a BART determination for any visibility-impairing air pollutant emitted by a BART eligible source. These commenters stated that undertaking a BART analysis for all pollutants emitted by a major stationary source is an unnecessary administrative burden with minimal environmental benefit. Commenters argued that Congress intended for BART to apply only to those pollutants for which a source is major. Commenters accordingly recommended that the 250 ton per year threshold apply to each pollutant emitted by a source and that BART apply only to those pollutants which meet this threshold. A number of these commenters argued alternatively that only those pollutants from a source demonstrated, individually, to cause or contribute to visibility impairment are required to go through a BART determination.

Final rule. We disagree with the comment that emissions of different visibility-impairing pollutants must be added together to determine whether a source exceeds the 250 ton per year threshold. The CAA, in section 169A(g)(7), defines a "major stationary source" as one with the potential to emit 250 tons or more of "any pollutant."

We disagree with comments that the BART analysis is required only for those pollutants that individually exceed the 250 ton per year threshold. Section 169A(b)(2)(A) specifically requires States to submit SIPs that include a requirement that a major stationary source

> which, as determined by the State * * * emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any [Class I area], shall procure, install, and operate * * * the best available retrofit technology, as determined by the State * * * for controlling emissions from such source for the purpose of eliminating or reducing any such impairment.

The regional haze regulations similarly require that the States submit a SIP that contains

A determination of BART for each BART-eligible source in the State that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area.

40 CFR 51.308(e)(1)(ii). Nothing in these statutory or regulatory requirement suggests that the BART analysis is limited to those pollutants for which a source is considered major. At best, these provisions can be read as requiring a BART determination only for those emissions from a specific source which do, in fact, cause or contribute to visibility impairment in a particular Class I area, or which could reasonably be anticipated to do so. Commenters, however, have not presented any evidence that as a general matter emissions of less than 250 tons per year of $PM_{2.5}$, SO_2, or other visibility-impairing pollutants from potential BART sources do not "cause or contribute to any impairment of visibility" in any of the Class I areas covered by the regional haze rule. As there is no such evidence currently before us, there is no basis to conclude that the States are required to make BART determinations only for those pollutants emitted in excess of 250 tons per year.

At the same time, we agree with certain commenters that the CAA does not require a BART determination for any visibility impairing pollutant emitted by a source, regardless of the amount. After reviewing the language of the Act and the comments received, we have concluded that our interpretation of the relevant language in section 169A(b)(2)(A) of the Act in the 2004 proposed guidelines is not necessarily the best reading of the BART provisions. Section 169A(b)(2)(A) of the Act can be read to require the States to make a determination as to the appropriate level of BART controls, if any, for emissions of any visibility impairing pollutant from a source. Given the overall context of this provision, however, and that the purpose of the BART provision is to eliminate or reduce visibility impairment, it is reasonable to read the statute as requiring a BART determination only for those emissions from a source which are first determined to contribute to visibility impairment in a Class I area.

The interpretation of the requirements of the regional haze program reflected in the discussion above does not necessitate costly and time-consuming analyses. Consistent with the CAA and the implementing regulations, States can adopt a more streamlined approach to making BART determinations where appropriate. Although BART determinations are based on the totality of circumstances in a given situation, such as the distance of the source from a Class I area, the type and amount of pollutant at issue, and the availability and cost of controls, it is clear that in some situations, one or more factors will clearly suggest an outcome. Thus, for example, a State need not undertake an exhaustive analysis of a source's impact on visibility resulting from relatively minor emissions of a pollutant where it is clear that controls would be costly and any improvements in visibility resulting from reductions in emissions of that pollutant would be negligible. In a scenario, for example, where a source emits thousands of tons of SO_2 but less than one hundred tons of NO_X, the State could easily conclude that requiring expensive controls to reduce NO_X would not be appropriate. In another situation, however, inexpensive NO_X controls might be available and a State might reasonably conclude that NO_X controls were justified as a means to improve visibility despite the fact that the source emits less than one hundred tons of the pollutant. Moreover, as discussed below, we are revising the regional haze regulations to allow the States to exempt *de minimis* emissions of SO_2, NO_X, and $PM_{2.5}$ from the BART determination process which should help to address the concerns of certain commenters associated with the burden of a broad BART analysis.

De minimis levels

Comments. Many commenters agreed that we should establish *de minimis* levels for individual pollutants in order to allow States and sources to avoid BART determinations for pollutants emitted in relatively trivial amounts. Many commenters suggested that States would be unlikely to impose emission limits for pollutants emitted at the proposed *de minimis* levels because it would not be cost-effective to do so and such emission reductions could not be expected to produce any perceptible improvements in visibility. Several commenters agreed that the pollutant coverage requirements for BART eligibility should be consistent with those for the PSD program, but others argued that BART should be required only for pollutants emitted in amounts greater than 250 tons per year. Commenters also noted that the guidelines were not clear as to whether the *de minimis* provision would apply on a plant-wide or unit by unit basis. A few commenters also noted that the final guidelines should clarify where in the BART determination process *de minimis* levels may be used.

Other commenters opposed the use of *de minimis* exemptions. These commenters argued that it would be unreasonable to rule categorically that a certain level of emissions had a trivial impact on visibility without assessing the impacts of these emissions in particular circumstances. These commenters argued that States should consider the emissions of all visibility-impairing pollutants in a BART determination regardless and that, consequently, there should be no *de minimis* levels.

Final rule. As proposed in 2004, we believe that it is reasonable to give States the flexibility to establish *de minimis* levels so as to allow them to exempt from the BART determination process pollutants emitted at very low levels from BART-eligible sources. As explained by the D.C. Circuit, "categorical exemptions from the requirements of a statute may be permissible 'as an exercise of agency power, inherent in most statutory schemes, to overlook circumstances that in context may fairly be considered *de minimis*.' "[20] The ability to create *de minimis* exemptions from a statute is a tool to be used in implementing the legislative design.[21]

The intent of Congress in requiring controls on emissions from certain major stationary sources was to eliminate or reduce any anticipated contribution to visibility impairment from these sources. This, as section 169A(b)(2)(A) states, is the "purpose" of BART. In making a determination as to the appropriate level of controls, however, the States are required to take into account not only the visibility benefits resulting from imposing controls on these sources but also the costs of complying with the BART provision. The BART provision is accordingly designed to ensure that the States take into consideration all emissions of certain stationary sources in making a BART determination, but also to provide States with the flexibility to include the costs and benefits of controlling these sources in the calculus of determining the appropriate level of BART.

We believe it would be permissible for States to create *de minimis* levels at a low level. If a State were to undertake a BART analysis for emissions of less than 40 tons of SO_2 or NO_X or 15 tons of PM_{10} from a source, it is unlikely to result in anything but a trivial improvement in visibility. This is

[20] *EDF et al.* v. *EPA*, 82 F.3d 451, 466 (D.C. Cir. 1996) citing *Alabama Power* v. *Costle*, 636 F.2d 323 (D.C. Cir. 1979).

[21] Id.

because reducing emissions at these levels would have little effect on regional emissions loadings or visibility impairment. We believe most States would be unlikely to find that the costs of controlling a few tons of emissions were justified. Because the overall benefits to visibility of requiring BART determinations for emissions of less than the *de minimis* levels would be trivial, we are amending the regional haze rule to make clear that the States have this flexibility.

The *de minimis* levels discussed today apply on a plant-wide basis. Applying *de minimis* levels on a unit by unit basis as suggested by certain commenters could exempt hundreds of tons of emissions of a visibility-impairing pollutant from BART analysis. In at least some of the twenty-six source categories covered by the BART provisions, a single control device can be used to control emissions from multiple units. Thus, it is possible that while emissions from each unit are relatively trivial, the costs of controlling emissions from multiple units might be cost-effective in light of the BART-eligible source's total emissions of the pollutant at issue. States should consider the control options in such situations and determine the appropriate approach for the specific source.

We are revising the regional haze rule to provide States with the ability to establish *de minimis* levels up to the levels proposed in 2004. We believe States may, if they choose, exclude from the BART determination process potential emissions from a source of less than forty tons per year of SO_2 or NO_X, or 15 tons per year for PM_{10}. (Note also that for sources that are BART-eligible for one pollutant, we also believe that States could allow those sources to model the visibility impacts of pollutants at levels between *de minimis* and 250 tons in order to show that the impact is negligible and should be disregarded. See section D below). In the guidelines, we include this as part of the BART determination in section IV of the guidelines. (We note that these emission levels represent the maximum allowable *de minimis* thresholds—States retain their discretion to set the thresholds at lesser amounts of each pollutant, or to not provide any pre-determined *de mininis levels.*) We believe that this approach is the clearest method for exempting trivial emissions from the BART determination process. Alternatively, States may find it useful to exclude *de minimis* emissions in identifying whether a source is subject to BART in section III of the guidelines. Either approach is consistent with the regulation issued in this rule.

D. How To Determine Which BART-eligible Sources Are "Subject to BART"

Cause or Contribute

Background. Under section 169A(b)(2)(A) of the Act, each State must review its BART eligible sources and determine whether they emit "any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in [a Class I] area." If a source meets this threshold, the State must then determine what is BART for that source.

Proposed rule. In the reproposed guidelines, we identified three options for States to use in determining which BART-eligible sources meet the test set forth in section 169A(b)(2)(A) of the CAA. To determine whether a BART-eligible source is "reasonably anticipated to cause or contribute to visibility impairment," the first proposed option was that a State could choose to consider the collective contribution of emissions from all BART-eligible sources and conclude that all BART-eligible sources within the State are "reasonably anticipated to cause or contribute" to some degree of visibility impairment in a Class I area. The preamble to the 1999 regional haze rule explains at length why we believe that looking to the collective contribution of many sources over a broad area is a reasonable approach, and we explained in the 2004 reproposed guideline that we believed that a State's decision to use a cumulative analysis at this stage of the BART determination process would be consistent with the CAA and the findings of the D.C. Circuit in *American Corn Growers.*

The second proposed option was to allow a State to demonstrate, using a cumulative approach, that none of its BART-eligible sources contribute to visibility impairment. Specifically, we proposed to provide States with the option of performing an analysis to show that the full group of BART-eligible sources in a State cumulatively do not cause or contribute to visibility impairment in any Class I areas.

As a third option, we proposed that a State may choose to determine which sources are subject to BART based on an analysis of each BART-eligible source's individual contribution. We labeled this option as an "Individualized Source Exemption Process," and proposed that States use an air quality model to determine an individual source's contribution to visibility impairment, calculated on a 24 hour basis, using allowable emissions, and compared to an established threshold.

Comments. Several commenters expressed the view that EPA was misinterpreting the *American Corn Growers* case to allow the States to apply a collective contribution test in determining whether BART-eligible sources are subject to BART. These commenters took the position that, because this approach does not allow for a source to show that it does not individually cause or contribute to visibility impairment, it is incompatible with the language of section 169A(b)(2)(A)of the Act. They argued that EPA should modify the provisions in the proposed rule to ensure that an individual source is afforded the opportunity to conduct an analysis to demonstrate that its emissions do not impair visibility in any Class I area. Conversely, several commenters indicated that the option to determine that all potential BART sources contribute to regional haze should be the starting point of determining BART eligibility.

Many industry commenters and some States supported the second proposed option which would allow a State to demonstrate through an analysis of the collective contribution of all its BART-eligible sources that none of these sources contribute to visibility impairment. Several of these commenters added, however, that if this cumulative analysis were to show a contribution, then, consistent with the decision in *American Corn Growers,* the State must allow each individual source to demonstrate that its own emissions do not, by themselves, contribute to the problem of visibility impairment. One commenter requested clarification on what visibility threshold a State should use in determining that no sources are reasonably anticipated to cause or contribute to any impairment in a Class I area.

A number of commenters supported the third option for determining BART applicability based on an analysis of source-specific effects on visibility. However, many of the commenters stated that the CAA requires that the States either conduct such an analysis in determining those sources subject to BART, or allow an individual source to make a showing that it does not cause or contribute to visibility impairment. In addition, although supportive of the general notion of allowing for an exemption process for BART-eligible sources, several commenters stated that the third option contained burdensome modeling requirements, and that States need a more flexible, straightforward, and less costly method to make the "cause or contribute" determination.

Several environmental groups commented that the proposed options potentially go too far in allowing sources to be exempted from the BART requirements. These commenters asserted that EPA should clarify that States may not allow a BART-eligible source to avoid the BART requirements without an affirmative demonstration by the State, or by the source, showing that the source does not emit any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area. Absent such a demonstration, they argue, a State may not choose to waive the requirement to conduct a BART review of the source.

Final rule. The final BART guidelines adopt the general approach contained in the reproposal, providing the States with several options for identifying the sources subject to BART. The final BART guidelines describe the options contained in the reproposal as well as one new option. The discussion of options in the final guidelines are structured somewhat differently from the reproposal, and the options are explained in greater detail. The guidelines reaffirm that a State may choose to consider all BART-eligible sources to be subject to BART, and to make BART determinations for all its BART-eligible sources.[22] For States that choose to consider exempting some or all of their BART-eligible sources from review, the guidelines then discuss three options that States may use to determine whether its sources are "reasonably anticipated to cause or contribute" to visibility impairment at a Class I area. Options 1 and 3 are similar to options in the 2004 reproposal; under option 1, States may use an individual source attribution approach, while option 3 provides the States with an approach for demonstrating that no sources in a State should be subject to BART. Option 2 is new; it is an approach for using model plants to exempt individual sources with common characteristics.

Threshold for visibility impact. One of the first steps in determining whether sources cause or contribute to visibility impairment for purposes of BART is to establish a threshold (quantified in units called "deciviews") against which to measure the visibility impact of one or more sources. We believe that a single source that is responsible for a 1.0 deciview change or more should be considered to "cause" visibility impairment; a source that causes less than a 1.0 deciview change may still contribute to visibility impairment and thus be subject to BART.

The guidelines note that because of varying circumstances affecting different Class I areas, the appropriate threshold for determining whether a source "contributes to any visibility impairment" for the purposes of BART may reasonably differ across States. Although the appropriate threshold may vary, the Guidelines state that the contribution threshold used for BART applicability should not be higher than 0.5 deciviews. We discuss threshold issues in greater detail in the subsection immediately following this one, entitled *Metric for Visibility Degradation.*

Pollutants

The guidelines direct that States should look at SO_2, NO_X, and direct particulate matter (PM) emissions in determining whether sources cause or contribute to visibility impairment, including both PM_{10} and $PM_{2.5}$. Consistent with the approach for identifying BART-eligible sources, States do not need to consider less than *de minimis* emissions of these pollutants from a source.

States may use their best judgement to determine whether VOC or ammonia emissions are likely to have an impact on visibility in an area. In addition, they may use PM_{10} or $PM_{2.5}$ as an indicator for $PM_{2.5}$ in determining whether a source is subject to BART. In determining whether a source contributes to visibility impairment, however, States should distinguish between the fine and coarse particle components of direct particulate emissions. Although both fine and coarse particulate matter contribute to visibility impairment, the long-range transport of fine particles is of particular concern in the formation of regional haze. Air quality modeling results used in the BART determination will provide a more accurate prediction of a source's impact on visibility if the inputs into the model account for the relative particle size of any directly emitted particulate matter (*i.e.* PM_{10} vs. $PM_{2.5}$).

We believe that PM_{10} is likely to contribute more to regional haze in arid areas than humid areas. As the Grand Canyon Visibility Transport Commission (GCTVC) recognized,[23] States in the arid West, in particular, will need to take the coarse fraction of particulate matter into account in determining whether a source meets the threshold for BART applicability.

Option 1. We agree with commenters supporting the use of an individual source analysis in determining if a BART-eligible source causes or contributes to visibility impairment. Consistent with *American Corn Growers,* this option provides a method for a State to evaluate the visibility impact from an individual source and show that the source is not reasonably anticipated to cause or contribute to visibility degradation in a Class I area and thus may be exempt from BART. (Note also that an individual source analysis is used to inform the BART determination). In general, a dispersion model is used to assess the visibility impact from a single source, and that impact is compared to a threshold which is determined by the State. The threshold (quantified in deciviews) is the numerical metric that is used to define "cause or contribute"; if a source's impact is below the threshold, a State may exempt the source from BART; otherwise the source would be subject to BART.

We discuss specific issues on the individualized source attribution process, including changes since proposal and issues raised by commenters, in the subsections immediately following this one: Metric for visibility degradation; Use of CALPUFF for visibility modeling; The use of natural conditions in determining visibility impacts for reasonable progress and comparison to threshold values; Modeling protocol; and Alternatives for determining visibility impacts from individual sources.

Option 2. In the final guideline, we describe a modified approach, using model plants based on representative sources sharing certain characteristics, that the States may use to simplify the BART determination process, either to exempt (individually or as a group) those small sources that are not reasonably anticipated to cause or contribute to visibility impairment, or to identify those large sources that clearly should be subject to BART review. States could use the CALPUFF model, for example, to estimate levels of visibility impairment associated with different combinations of emissions and distances to the nearest Class I area. In carrying out this approach, the State could then reflect groupings of specific types of sources with important common characteristics, such as emissions, stack heights and plume characteristics, and develop "composite model plants." Based on CALPUFF

[22] States choosing this approach should use the data being developed by the regional planning organizations, or on their own, as part of the regional haze SIP development process to make the showing that the State contributes to visibility impairment in one or more Class I areas.

[23] Grand Canyon Visibility Transport Commission, Recommendations for Improving Western Vistas, Report to the U.S. EPA, June 10, 1996.

analyses of these model plants, a State may find that certain types of sources are clearly reasonably anticipated to cause or contribute to visibility impairment. Conversely, representative plant analyses may show that certain types of sources are not reasonably anticipated to cause or contribute to visibility impairment. Based on the modeling results, a State could exempt from BART all sources that emit less than a certain amount per year and that are located a certain distance from the nearest Class I area.

Our analyses of visibility impacts from model plants provide a useful example of the type of analyses that might be used to exempt categories of sources from BART.[24] Based on our model plant analysis, EPA believes that a State could reasonably choose to exempt sources that emit less than 500 tons per year of NO_X or SO_2 (or combined NO_X and SO_2), as long as they are located more than 50 kilometers from any Class I area; and sources that emit less than 1000 tons per year of NO_X or SO_2 (or combined NO_X and SO_2) that are located more than 100 kilometers from any Class I area.

In our analysis, we developed two model plants (a EGU and a non-EGU), with representative plume and stack characteristics, for use in considering the visibility impact from emission sources of different sizes and compositions at distances of 50, 100 and 200 kilometers from two hypothetical Class I areas (one in the East and one in the West). Because the plume and stack characteristics of these model plants were developed considering the broad range of sources within the EGU and non-EGU categories, they do not necessarily represent any specific plant. However, the results of these analyses may be instructive in the development of an exemption process for groups of BART-eligible sources, without modeling each of these sources individually.

States may want to conduct their own model plant analysis that take into account local, regional, and other relevant factors (such as meteorology, sulfur dioxide, nitrogen dioxide, and ammonia). If so, you may want to consult your EPA Regional Office to ensure that any relevant technical issues are resolved before you conduct your modeling.

In preparing our hypothetical examples, we have made a number of assumptions and exercised certain modeling choices; some of these have a tendency to lend conservatism to the results, overstating the likely impacts, while others may understate the modeling results. On balance, when all of these factors are considered, we believe that our examples reflect realistic treatments of the situations being modeled.[25] A summary of the more significant elements and their implications is provided below.

Features of the modeling examples which may understate visibility impacts

- An annual emission rate was used for the example modeling (*e.g.* 10,000 TPY divided by 365 days divided by 24 hours). "Real world" sources have variable emission rates, and in any 24 hour period may be operating well above the annual rate.
- The monthly average relative humidity was used, rather than the daily average humidity, and would contribute to lowering the peak values in daily model averages.
- A 24-hour average was calculated from modeled hourly visibility impacts, reducing the impact of any one particular hour that could be higher due to a number of meteorological effects.

Features of the modeling examples which may overstate visibility impacts

- We located receptors using a grid of concentric circles for distances of 50, 100 and 200 km. A receptor was placed every 10 degrees around each circle, and highest impacts were reported regardless of direction from the source. In actuality, receptors would be located only in the Class I area, or in only one direction from the source.
- We used simplified chemistry (*i.e.* for conversion of SO_2 and NO_X to fine particles) and disperson techniques which tend to overstate model impacts.

Special care should be used to ensure that the criteria used in the modeling are appropriate for a given State. Our modeling may not be appropriate for every region of the country, due to the unique characteristics of different Class I areas and varying meteorological and geographical conditions in different regions. In addition, States may want to design their own model plants taking into account the types of sources at issue in their region.

Option 3. Under the BART guidelines, a State may consider exempting all its BART-eligible sources from BART by conducting analyses that show that all of the emissions from BART-eligible sources in their State, taken together, are not reasonably anticipated to cause or contribute visibility impairment. To make such a showing, a State could use CALPUFF or another appropriate dispersion model to evaluate the impacts of individual sources on downwind Class I areas, aggregating those impacts to determine the collective contribution from all-BART eligible sources in the State. A State with a sufficiently large number of BART-eligible sources could also make such a showing using a photochemical grid model.[26]

We agree with commenters who pointed out that the option of allowing a State to demonstrate that the full group of BART-eligible sources in the State do not contribute to visibility impairment would, by default, satisfy an individual source contribution assessment. Commenters have not shown any reason to believe that if the sum total of emissions from the BART-eligible sources in a State do not "cause or contribute" to visibility impairment in any Class I area, that emissions from one such source will meet the threshold for BART applicability. A State following this approach accordingly need not undertake an affirmative demonstration based on a source by source analysis of visibility impacts to find that its sources are not subject to BART.

Metric for Visibility Degradation

Background. The 2004 reproposed guidelines contained a proposed threshold for the States to use in determining whether an individual source could be considered to cause visibility impairment in a Class I area. We proposed a 0.5 deciview change relative to natural background conditions,[27] as a numerical threshold for making this determination.[28]

[24] Supplement to CALPUFF Analysis in Support of the June 2005 Changes to the Regional Haze Rule, U.S. Environmental Protection Agency, June 15, 2005, Docket No. OAR–2002–0076.

[25] CALPUFF Analysis in Support of the June 2005 Changes to the Regional Haze Rule, U.S. Environmental Protection Agency, June 15, 2005, Docket No. OAR–2002–0076.

[26] For regional haze applications, regional scale modeling typically involves use of a photochemical grid model that is capable of simulating aerosol chemistry, transport, and deposition of airborne pollutants, including particulate matter and ozone. Regional scale air quality models are generally applied for geographic scales ranging from a multi-state to the continental scale. Because of the design and intended applications of grid models, they may not be appropriate for BART assessments, so States should consult with the appropriate EPA Regional Office prior to carrying out any such modeling.

[27] *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule,* (U.S. Environmental Protection Agency, September 2003. *http://www.epa.gov/ttncaaa1/t1/memoranda/rh_envcurhr_gd.pdf.* Natural background conditions, expressed in deciviews, are defined for each Class I area. EPA has issued guidance for estimating natural background conditions which has estimates of default conditions as well as measures to develop refined estimates of natural conditions.

[28] In the proposal we noted that a 0.5 deciview change in visibility is linked to "perceptibility," or

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Several commenters said that the 0.5 deciview threshold is too high. A recurring comment was that the statutory BART applicability test from CAA Section 169A(b)(2)(A) contains two separate elements: "causation" of any visibility impairment and "contribution" to any such impairment. Commenters pointed out that by setting a threshold of 0.5 deciviews, we had combined "cause or contribute" into a single test of causality, thus effectively eliminating the "contribution" element of the BART applicability test. The commenters asserted that a single BART-eligible source can "contribute" to visibility impairment with impacts much lower than 0.5 deciviews. They argued that we must set the minimum threshold for individual source contribution to visibility impairment at the lowest level detectable by modeling or other appropriate analysis, and that this minimum individual contribution level must in any event be set at no greater than a 0.1 deciview change relative to natural conditions, which is a clearly measurable level. One commenter suggested that a cause or contribute threshold be set at some percentage of the "just noticeable" change of 0.5 deciviews.

Another commenter said that in a case where multiple sources each have a visibility impact of less than a 0.5 deciview change, but together result in a change of more than 0.5 deciview, each of these sources contributes to the resulting visibility impairment. This commenter asserted that BART guidelines that result in exemptions for these "contributing" sources would subvert the goals of the regional haze program.

Similarly, several commenters suggested that if any combination of BART eligible sources causes visibility impairment in a Class I area of more than 0.5 deciviews (by CALPUFF modeling for any 24-hour period, for example), that State should determine that each individual source is subject to BART. Thus, the commenter added, the court's concern about the lack of "empirical evidence of a source's contribution to visibility impairment" would be addressed.

Two commenters said that our requirement to use the maximum 24-hour value over the 5-year period of meteorological data in the modeling, as proposed, is too stringent, unreasonable, inappropriate, and departs from the previous methodologies for the regional haze program. Additionally they said that the threshold is restrictive because the single highest 24-hour modeled impact over a three- or five-year period may be influenced by short-term weather conditions, like high humidity, and the BART applicability determination should not be made based on a one-time occurrence.

One commenter said that whatever the final threshold for a single-source impact for BART sources, EPA should clarify that the purpose of this modeling assessment is to evaluate a source's anticipated contribution to uniform regional haze over the Class I area. EPA should state that the assumption of a uniform haze contribution based on CALPUFF modeling eliminates the need to assess issues related to the size of the Class I area, views within a Class I area, and weather impact interactions. Finally, one commenter said that thresholds should be established separately for the eastern and western regions of the United States, as natural visibility conditions are established separately for eastern and western regions in the guidance.

Final Rule. Today's guidelines advise States to use a deciview metric in defining "cause or contribute," as explained further below. The fact that the deciview is also used to track progress toward the goal of natural visibility does not in any way indicate that we are "converting" a "goal" into a requirement.[31] Use of the same metric in the "cause or contribute" context as used for establishing reasonable progress goals, tracking changes in visibility conditions, and defining baseline, current, and natural conditions simply provides for a consistent approach to quantifying visibility impairment.

In response to commenters who said we conflated the "cause or contribute" test, we are clarifying that for purposes of determining which sources are subject to BART, States should consider a 1.0 deciview change or more from an individual source to "cause" visibility impairment, and a change of 0.5 deciviews to "contribute" to impairment.[32]

In a regulatory context, we believe that a State's decision as to an

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[31] Moreover, the fact that the ultimate purpose of the visibility provisions is expressed as a "goal" does not mean that all aspects of the program are merely aspirational. CAA section 169A(a)(4) requires EPA to establish regulations to ensure that reasonable progress is made toward the national visibility goal, and 169A(b)(2) provides that EPA must require SIPs to contain emission limits, schedules of compliance, and other measures as may be necessary to make reasonable progress towards meeting the goal.

[32] If "causing" visibility impairment means causing a humanly perceptible change in visibility in virtually all situations (*i.e.* a 1.0 deciview change), then "contributing" to visibility impairment must mean having some lesser impact on the conditions affecting visibility that need not rise to the level of human perception.

appropriate threshold for contribution could depend upon the number of sources affecting a class I area. To illustrate, if there were only one emissions source affecting visibility in a class I area, that source could have a deciview impact only slightly below the perceptibility threshold without contributing to noticeable impairment. However, if there were 100 sources each changing visibility by 0.1 deciviews, the total impact would be a 10-deciview change in visibility. In this hypothetical example, all 100 sources would be contributing, in equal amounts, to substantial visibility impairment.

Because circumstances will vary in different locations, we believe that States should have discretion to set an appropriate threshold depending on the facts of the situation. We believe, however, that it would be difficult for a State to justify a threshold higher than 0.5 deciviews. In particular, 0.5 deciviews represents one half of the 1.0 deciview level that we are equating with a single source "causing" visibility degradation. Typically, there are multiple sources that affect visibility in class I areas, so a source causing a 0.5 deciview change can be expected to be contributing to noticeable visibility impairment.

In determining whether the maximum threshold of 0.5 deciviews or a lower threshold is appropriate for purposes of BART, we believe that States should consider the number of emissions sources affecting the class I area and the magnitude of the individual sources' impacts.[33] In general, a larger number of sources causing impacts in a class I area may warrant a lower contribution threshold. In selecting a threshold, States may want to take into account the fact that individual sources have varying amounts of impact on visibility in class I areas. Depending on the facts regarding the number of sources affecting a class I area and their modeled impacts, the State could set a threshold that captures those sources responsible for most of the total visibility impacts, while still excluding other sources with very small impacts.[34]

We also note that under this guidance, States would have discretion in setting the threshold for "contributes to" based on modeled impacts of sources. Consistent with *American Corn Growers,* we are not requiring States to find sources subject to BART regardless of their impact on Class I areas. We are suggesting that, in establishing a threshold for assessing contribution for BART, it may be logical to draw a line between "contribution" and "non-contribution" based on the number and magnitude of the various sources affecting the Class I areas at issue. Such an approach gives States the ability to assess the empirical evidence showing contribution and to design an appropriate regulatory regime in light of the nature of the problem. We note that for 750 MW power plants, such a line drawing exercise is likely to be unnecessary, as such sources will in most or all cases have impacts far exceeding 1.0 deciviews.

Finally, we disagree that separate threshold levels should be established based on geography because a unit change in visibility expressed in deciviews, perceived or measured, is the same regardless of geography. As explained in the 1999 regional haze rule, the deciview can be used to express changes in visibility impairment in a way that corresponds to human perception in a linear manner. As a result, using the deciview as the metric for measuring visibility means, for example, that a one deciview change in a highly impaired environment would be perceived as roughly the same degree of change as one deciview in a relatively clear environment, and geography is not a factor.

Interpretation of CALPUFF Results

The standard CALPUFF modeling run provides day-by-day estimates of a source's visibility effects over a five-year period. In the proposed BART guideline, we indicated that if the maximum daily visibility value at any receptor over the five years modeled is greater than the "cause or contribute" threshold, then the State should conclude that the source is subject to BART. A number of commenters took issue with our proposal to use the 24-hour maximum modeled visibility impact over five years of meteorological data. Several of them pointed out, for example, that the maximum modeled 24-hour impact may be an outlier unduly influenced by weather. We agree that the maximum modeled effect in a five-year period could be the result of unusual meteorology. We also recognize that, although CALPUFF is the best currently available tool for analyzing the visibility effects of individual sources, it is a model that includes certain assumptions and uncertainties. Thus, we agree with commenters that a State should not necessarily rely on the maximum modeled impact in determining whether a source may reasonably be anticipated to contribute to visibility impairment in a Class I area.

The final guideline states that it would be reasonable for States to compare the 98th percentile of CALPUFF modeling results against the "contribution" threshold established by the State for purposes of determining BART applicability. Some stakeholders have argued for the 90th percentile value, or even lower, contending that EPA should not use extreme cases to make BART applicability decisions. EPA agrees that, in most cases, important public policy decisions should not be based on the extreme tails of a distribution. We have concluded, however, that the 98th percentile is appropriate in this case.

The use of 90th percentile value would effectively allow visibility effects that are predicted to occur at the level of the threshold (or higher) on 36 or 37 days a year. We do not believe that such an approach would be consistent with the language of the statute. Second, we note that the 98th percentile value would only be used to determine whether a particular BART-eligible source would be subject to further review by the State. In determining what, if any, emission controls should be required, the State will have the opportunity to consider the frequency, duration, and intensity of a source's predicted effect on visibility.

On the other hand, there are other features of our recommended modeling approach that are likely to overstate the actual visibility effects of an individual source. Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source. Because of these features and the uncertainties associated with the model, we believe it is appropriate to use the 98th percentile—a more robust approach that does not give undue weight to the extreme tail of the distribution. The use of the 98th percentile of modeled visibility values would appear to exclude roughly 7 days per year from consideration. In our judgment, this approach will effectively capture the sources that contribute to visibility impairment in a Class I area, while minimizing the likelihood that the highest modeled visibility impacts might be caused by unusual meteorology or conservative assumptions in the model.

[33] All states are working together in regional planning organizations, and we expect that states will have modeling information that identifies sources affecting visibility in individual class I areas, and the magnitude of their impacts.

[34] Under our guidelines, the contribution threshold should be used to determine whether an individual source is reasonably anticipated to contribute to visibility impairment. You should not aggregate the visibility effects of multiple sources and compare their collective effects against your contribution threshold because this would inappropriately create a "contribution to contribution" test.

Use of CALPUFF for Visibility Modeling

Background. In providing the States with the option of making a determination as to which sources are subject to BART based on a consideration of each source's individual contribution to visibility impairment, we proposed that States use an air quality model such as CALPUFF. We also proposed that States use a CALPUFF or other EPA approved model in the BART analysis itself. The CALPUFF system, as explained in the 2004 reproposed guideline, consists of a diagnostic meteorological model, a gaussian puff dispersion model with algorithms for chemical transformation and complex terrain, and a post processor for calculating concentration fields and visibility impacts.

The regional haze rule addresses visibility impairment caused by emissions of fine particles and their precursors. As fine particle precursors, such as SO_2 or NO_X, are dispersed, they react in the atmosphere with other pollutants to form visibility-impairing pollutants. In fact, Congress implicitly recognized in 1977 the role of chemical transformation in creating visibility impairment, when it stated that the "visibility problem is caused primarily by emissions of SO_2, [NO_X], and particulate matter." [35] In most cases, to predict the impacts of a source's specific contribution to visibility impairment, a State will need a tool that takes into account not only the transport and diffusion of directly emitted $PM_{2.5}$ but also one that can address chemical transformation.

Because the air quality model CALPUFF is currently the best application available to predict the impacts of a single source on visibility in a Class I area, we proposed that a CALPUFF assessment be used as the preferred approach first, for determining whether an individual source is subject to BART, and second, in the BART determination process. The CALPUFF assessment is specific to each source, taking into account the individual source's emission characteristics, location, and the particular meteorological, topographical, and climatological conditions of the area in which the source is located, any of which may have an impact on the transport of $PM_{2.5}$ and its precursors. CALPUFF can be used to estimate not only the effects of directly emitted $PM_{2.5}$ emissions from a source, but also to predict the visibility impacts from the transport and chemical transformation of fine particle precursors.

The CALPUFF model is generally intended for use on scales from 50 km to several hundred kilometers from a source. As a general matter, States will typically need to assess the impacts of potential BART sources on Class I areas located more than 50 km from the source.[36] However, in situations where the State is assessing visibility impacts for source-receptor distances less than 50 km, we proposed that States use their discretion in determining visibility impacts, giving consideration to both CALPUFF and other EPA-approved methods. As an example, we suggested that States could use an appropriate local-scale plume impact model, such as PLUVUEII,[37] to determine whether a source's emissions are below a level that would be reasonably anticipated to cause or contribute to visibility impairment in any Class I area.

Comments. A number of States, environmental groups, and some industry commenters strongly supported the use of CALPUFF as proposed. Many commenters supported the use of CALPUFF but indicated that States must have the flexibility to use additional tools for their individual source analyses. Some suggested options for the "cause or contribute" determination were the use of photochemical grid models, or more simplified, non-modeling approaches. Commenters claimed that States must have the option to incorporate advances in science and technologies into models or other applications that may produce more accurate simulations of meteorology, chemistry, and visibility impairment. Other industry groups and States argued that CALPUFF has significant limitations, especially simulating complex atmospheric chemistry, and that EPA's recommendation of CALPUFF as the preferred approach is therefore inappropriate.

Another issue raised by commenters was the use of CALPUFF for estimating secondary particulate matter formation. Commenters recognized that CALPUFF was incorporated into the "Guideline on Air Quality Models" at 40 CFR part 51, appendix W in April 2003 as the preferred model for Prevention of Significant Deterioration (PSD) increment and National Ambient Air Quality Standards (NAAQS) compliance assessments of long range transport of primary emissions of SO_2 and $PM_{2.5}$. However, commenters stated that CALPUFF has not been incorporated into the Guideline on Air Quality Models for predicting the secondary formation of PM. The commenters remarked that EPA guidance indicates that photochemical grid models be used to simulate secondary PM formation and concluded on this basis that the application of CALPUFF as we proposed is in conflict with our guidance.

Final rule. We believe that CALPUFF is an appropriate application for States to use for the particular purposes of this rule, to determine if an individual source is reasonably anticipated to cause or contribute to impairment of visibility in Class I areas, and to predict the degree of visibility improvement which could reasonably be anticipated to result from the use of retrofit technology at an individual source. We encourage States to use it for these purposes.[38]

CALPUFF is the best modeling application available for predicting a single source's contribution to visibility impairment. It is the only EPA-approved model for use in estimating single source pollutant concentrations resulting from the long range transport of primary pollutants. In addition, it can also be used for some purposes, such as the visibility assessments addressed in today's rule, to account for the chemical transformation of SO_2 and NO_X. As explained above, simulating the effect of precursor pollutant emissions on $PM_{2.5}$ concentrations requires air quality modeling that not only addresses transport and diffusion, but also chemical transformations. CALPUFF incorporates algorithms for predicting both. At a minimum, CALPUFF can be used to estimate the relative impacts of BART-eligible sources. We are confident that CALPUFF distinguishes, comparatively, the relative contributions from sources such that the differences in source configurations, sizes, emission rates, and visibility impacts are well-reflected in the model results. States can make judgements

[35] H.R. Rep. No. 95–294 at 204 (1077).

[36] To determine whether a BART-eligible source "may reasonably be anticipated to cause or contribute to any visibility impairment in any Class I area," it may not always be sufficient for the State to predict the impacts of a BART-eligible source only on the nearest Class I area (or on the nearest receptor in the nearest Class I area). The particular meteorological and topographical conditions, for example, could mean that a source's greatest impacts occurred at a Class I area other than the nearest one.

[37] PLUVUEII is a model used for estimating visual range reduction and atmospheric discoloration caused by plumes resulting from the emissions of particles, nitrogen oxides, and sulfur oxides from a single source. The model predicts the transport, dispersion, chemical reactions, optical effects and surface deposition of point or area source emissions. It is available at *http://www.epa.gov/scram001/tt22.htm#pluvue.*

[38] The model code and its documentation are available at no cost for download from *http://www.epa.gov/scram001/tt22.htm#calpuff.*

concerning the conservativeness or overestimation, if any, of the results. In fact, although we focused on the use of CALPUFF for primary pollutants in revising the Guideline of Air Quality Modeling, section 7.2.1.e. of the Guideline states:

e. CALPUFF (Section A.3) may be applied when assessment is needed of reasonably attributable haze impairment or atmospheric deposition due to one or a small group of sources. This situation may involve more sources and larger modeling domains than that to which VISCREEN ideally may be applied. The procedures and analyses should be determined in consultation with the appropriate reviewing authority (paragraph 3.0(b) and the affected FLM(s).

We believe that our proposed use of CALPUFF is thus fully in keeping with the *Guideline on Air Quality Models,* especially in light of the low triggering threshold for determining whether a source is reasonably anticipated to cause or contribute to visibility impairment in a Class I area, and the fact that the modeling results are used as only one of five statutory criteria evaluated to determine BART emission limits.

Even so, as commenters point out, CALPUFF has not yet been fully evaluated for secondary pollutant formation. For the specific purposes of the regional haze rule's BART provisions, however, we have concluded that CALPUFF is sufficiently reliable to inform the decision making process.

EPA revised the *Guideline on Air Quality Models* in 2003, in part, to add CALPUFF to the list of approved models for particular uses. At that time, we considered comments that CALPUFF should be approved for use in predicting the impact of secondary emissions on particulate matter concentrations. As we stated in the revision, CALPUFF represents a substantial improvement in methods for assessing long-range transport of air pollutants. However, as explained in the response to comments for that rulemaking, the modeling results in the context of a PSD review may be used as the sole determining factor in denying a source a permit to construct.[39] Although its use in simulating long-range transport is beneficial, given the significance of the modeling results in assessing increment consumption due to a single source's impacts, we made a determination that it would not be appropriate in the rulemaking revising Appendix W to approve CALPUFF for use in modeling secondary emissions.

In contrast to the significance of the modeling results in the PSD context, the use of CALPUFF in the context of the regional haze rule is not determinative of a source's ability to construct or operate. A State may use CALPUFF to determine whether a source can reasonably be anticipated to cause or contribute to visibility impairment and so should be subject to additional review to determine if the source should be subject to control.

Based on our analysis of the power plants covered by the guidelines, we believe that all but a handful of these plants have impacts of greater than 1.0 deciview on one or more Class I areas.[40] In fact, we anticipate that most of these plants are predicted to have much higher maximum impacts.[41] Because of the scale of the predicted impacts from these sources, CALPUFF is an appropriate or a reasonable application to determine whether such a facility can reasonably be anticipated to cause or contribute to any impairment of visibility. In other words, to find that a source with a predicted maximum impact greater than 2 or 3 deciviews meets the contribution threshold adopted by the States does not require the degree of certainty in the results of the model that might be required for other regulatory purposes.

In the unlikely case that a State were to find that a 750 MW power plant's predicted contribution to visibility impairment is within a very narrow range between exemption from or being subject to BART, the State can work with EPA and the FLM to evaluate the CALPUFF results in combination with information derived from other appropriate techniques for estimating visibility impacts to inform the BART applicability determination. Similarly for other types of BART eligible sources, States can work with the EPA and FLM to determine appropriate methods for assessing a single source's impacts on visibility.

As discussed in section E. below we also recommend that the States use CALPUFF as a screening application in estimating the degree of visibility improvement that may reasonably be expected from controlling a single source in order to inform the BART determination. As we noted in 2004, this estimate of visibility improvement does not by itself dictate the level of control a State would impose on a source; "the degree of improvement in visibility which may reasonably be anticipated to result from the use of [BART]" is only one of five criteria that the State must consider together in making a BART determination. The State makes a BART determination based on the estimates available for each criterion, and as the CAA does not specify how the State should take these factors into account, the States are free to determine the weight and significance to be assigned to each factor. CALPUFF accordingly is an appropriate application for use in combination with an analysis of the other statutory factors, to inform decisions related to BART.

We understand the concerns of commenters that the chemistry modules of the CALPUFF model are less advanced than some of the more recent atmospheric chemistry simulations. To date, no other modeling applications with updated chemistry have been approved by EPA to estimate single source pollutant concentrations from long range transport. In its next review of the Guideline on Air Quality Models, EPA will evaluate these and other newer approaches and determine whether they are sufficiently documented, technically valid, and reliable to approve for general use. In the meantime, as the Guideline makes clear, States are free to make their own judgements about which of these or other alternative approaches are valid and appropriate for their intended applications.

Theoretically, the CALPUFF chemistry simulations, in total, may lead to model predictions that are generally overestimated at distances downwind of 200 km. Again, States can make judgements concerning the conservativeness or overestimation, if any, of the results.

The use of other models and techniques to estimate if a source causes or contributes to visibility impairment may be considered by the State, and the BART guidelines preserve a State's ability to use other models. Regional scale photochemical grid models may have merit, but such models have been designed to assess cumulative impacts, not impacts from individual sources. Such models are very resource intensive and time consuming relative to CALPUFF, but States may consider their use for SIP development in the future as they are adapted and demonstrated to be appropriate for single source applications. However, to date, regional models have not been evaluated for single source applications. Their use may be more appropriate in the cumulative modeling options discussed

[39] Under CAA section 165(a), a major emitting facility may not be constructed unless the owner or operator of the facility demonstrates that the emissions from the facility will not cause or contribute air pollution in excess of an increment or NAAQS.

[40] CALPUFF Analysis in Support of the Regional Haze Rule, U.S. Environmental Protection Agency, April 15, 2005, Docket No. OAR–2002–0076.

[41] Ibid.

above.[42] In evaluating visibility improvement as one of the five factors to consider in setting BART controls, other models, used in combination with CALPUFF may be helpful in providing a relative sense of the source's visibility impact and can aid in informing the BART decision. A discussion of the use of alternative models is given in the *Guideline on Air Quality* in appendix W, section 3.2.

The Use of Natural Conditions in Determining Visibility Impacts for Reasonable Progress and Comparison to Threshold Values

Background. As set out in section 169A(a) of the CAA and stated in the 1999 regional haze rule, a return to natural visibility conditions, or the visibility conditions that would be experienced in the absence of human-caused impairment, is the ultimate goal of the regional haze program. To measure progress toward this goal, the regional haze rule requires that a comparison with natural conditions for the 20 percent best and worst days to calculate "reasonable progress" determinations. Default values for natural visibility conditions are provided in EPA guidance.[43] In the 2004 reproposal of the BART guidelines, we proposed that changes in visibility, expressed in deciviews, should be determined by comparing the impact from a single source to natural visibility conditions. That impact should then be compared to a threshold impact, also expressed in deciviews, to assess if a BART-eligible source should be subject to a BART review.

Comments. Opposing commenters said that a return to natural conditions is unattainable as it would require the elimination of every manmade source, and that changes should be compared against currently existing conditions. They added that true "natural conditions" cannot be verified, do not account for manmade emissions from other countries, and are not a realistic target for improvement. Further, they argued that natural conditions are a "goal" representing a benchmark that is relevant to the States' determination, under the regional haze program, of the level of "reasonable progress" to achieve; however they stated that there is no legal requirement (and there could not be a legal requirement) that the natural conditions goal ultimately must be achieved. Several commenters added that current visibility conditions make more sense as a baseline because sources that are subject to BART today will likely not be in operation in the 2064 time frame. A commenter added that using current visibility conditions for the analysis will give a more realistic, real-world prediction of whether controlling the source pursuant to BART will actually improve visibility. The commenter said that Congress did not intend for sources to have to consider retrofitting controls under the BART provision if those sources currently are not impacting real-world visibility. Other utility groups stated that in addition to international emissions, the estimated natural visibility conditions failed to account for natural phenomena such as sea salt, wildfires, and natural organics. One commenter noted that natural visibility estimates will be revised and refined over time and it would be unwise to compare impacts and improvements to a moving baseline.

On the other hand, numerous commenters supported the use of natural visibility conditions as a baseline for measuring visibility improvements. Several environmental groups said that any increase in the baseline beyond natural visibility conditions will unlawfully distort and weaken the BART requirement by effectively raising the applicability threshold in less protected, highly polluted areas, which would be illogical. Further, they pointed out that these BART-eligible sources clearly are contributing to the very manmade visibility impairment that the Act is explicitly designed to remedy by a return to natural conditions. They added that measuring natural conditions as opposed to some other baseline condition is a more appropriate approach, given that the planning goal is to achieve natural visibility by the end of the program. They also added that a baseline other than natural conditions would never assure "reasonable progress".

Finally, two commenters asked for clarification on the values for natural conditions to be used for estimating changes in visibility. The commenters appeared to assume that we intended for the comparison to be done for natural visibility conditions on the 20 percent best days.

Final Rule. We disagree with commenters saying that the use of natural conditions as the baseline for making visibility impact determinations is inappropriate. The visibility goal of the CAA is both the remedying of existing impairment, and prevention of future impairment. The court, in American Corn Growers, upheld our interpretation of that goal as the return to natural visibility conditions.[44] Long-term regional haze strategies are developed to make "reasonable progress" towards the CAA goal, and States must demonstrate reasonable progress in their regional haze State implementation plans (SIPs). Since the BART program is one component of that demonstration, visibility changes due to BART are appropriately measured against the target of natural conditions.

In establishing the goal of natural conditions, Congress made BART applicable to sources which "may be reasonably anticipated to cause or contribute to any impairment of visibility at any Class I area". Using existing conditions as the baseline for single source visibility impact determinations would create the following paradox: the dirtier the existing air, the less likely it would be that any control is required. This is true because of the nonlinear nature of visibility impairment. In other words, as a Class I area becomes more polluted, any individual source's contribution to changes in impairment becomes geometrically less. Therefore the more polluted the Class I area would become, the less control would seem to be needed from an individual source. We agree that this kind of calculation would essentially raise the "cause or contribute" applicability threshold to a level that would never allow enough emission control to significantly improve visibility. Such a reading would render the visibility provisions meaningless, as EPA and the States would be prevented from assuring "reasonable progress" and fulfilling the statutorily-defined goals of the visibility program. Conversely, measuring improvement against clean conditions would ensure reasonable progress toward those clean conditions.

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[42] For regional haze applications, regional scale modeling typically involves use of a photochemical grid model that is capable of simulating aerosol chemistry, transport, and deposition of airborne pollutants, including particulate matter and ozone. Regional scale air quality models are generally applied for geographic scales ranging from a multi-state to the continental scale. Because of the design and intended applications of grid models, they may not be appropriate for BART assessments, so States should consult with the appropriate EPA Regional Office prior to carrying out any such modeling.

[43] Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule, U.S. Environmental Protection Agency, September 2003. *http://www.epa.gov/ttncaaa1/t1/memoranda/rh_envcurhr_gd.pdf.* Natural background conditions, expressed in deciviews, are defined for each Class I area. EPA has issued guidance for estimating natural background conditions which has estimates of default conditions as well as measures to develop refined estimates of natural conditions.

[44] See also our explanation of the CAA goal provided in the regional haze rule at 64 FR at 35720–35722. We note that the court in *American Corn Growers* also observed, "the natural visibility goal is not a mandate, it is a goal." 291 F.3d at 27.

With regard to BART-eligible sources not being in operation for the duration of the program, a State, in making BART determinations, is explicitly directed by the CAA to account for the remaining useful life of a source. Thus, States may factor into their reasonable progress estimates those shut-downs that are required and effected in permit or SIP provisions. In addition, as provided for under our guidance,[45] proper accounting for international emissions and natural phenomena is in the 5 year SIP progress report, not in the setting of natural visibility estimates. Finally, these final BART guidelines use the natural visibility baseline for the 20 percent best visibility days for comparison to the "cause or contribute" applicability thresholds. We believe this estimated baseline is likely to be reasonably conservative and consistent with the goal of natural conditions.

Modeling Protocol

Background. The 2004 guidelines proposed that a written modeling protocol be submitted for assessing visibility impacts from sources at distances greater than 200 km from a Class I area. The proposal indicated that the protocol should include a description of the methods and procedures to follow, for approval by the appropriate reviewing authority; critical items to include in the protocol are meteorological and terrain data, source-specific information (stack height, temperature, exit velocity, elevation, and allowable emission rate of applicable pollutants), and receptor data from appropriate Class I areas.

Comments. All of the comments supported the development of a written modeling protocol. Industry, Federal, and State commenters said a modeling protocol should be required of all States and stakeholders who are performing the BART modeling analysis. Commenters said the protocol should allow all interested parties an opportunity to understand the modeling approach and how the results will be used, and that the State should provide opportunity for comments on the procedures prior to the publication of the final results.

Many utility groups commented that the protocol should provide States with flexibility and that the choice of models should be at the States' (or RPOs') discretion. Some commenters stressed that it is important that states and sources retain the flexibility to decide how to set up and run the selected model, while others asked for specific guidance on the setup of CALPUFF or other approved models, including on specific parameters (*e.g.* how to adjust for cases where sources are greater than 200 km from a Class I area).

Regarding the approval of a modeling protocol, some commenters said that the protocol should be approved by EPA. Others stated, however, that we should have only an advisory role in development of the protocol. They said that States are in a better position to determine which modeling input values best reflect conditions in their States.

Several commenters representing environmental groups said we should develop a CALPUFF protocol that must be followed and should include, among other items, meteorological data (*i.e.*, where available 5 years of data should be used), emissions reported for the same meteorological years, documented source parameters, model physical parameters, and assumed background concentrations for ozone and ammonia (based on nearby reliable observations and/or regional modeling results). They added that a protocol developed by EPA would help to produce consistent BART determinations across various sources and geographic areas for both shorter and longer distances. FLMs stated that this is also an appropriate time to create regional modeling platforms for CALPUFF, which would allow States and sources to run the model more expeditiously and more consistently. They recommended that we consider a multi-agency process to reach agreement on an appropriate modeling protocol prior to allowing BART applicability and control determinations to be based on model results. FLMs added that it would be helpful to establish a national procedure for this process, including a methodology for establishing natural background conditions, background ammonia concentrations, and determining sulfuric acid emission rates. Such a process, they said, could reasonably be engaged in prior to deadlines for state implementation plans, and would not delay implementation of the BART guidelines. The FLMs noted that consistent, nationally applicable guidance is essential, and that once it is developed, virtually no deviations should be allowed. Finally, they added that the CALPUFF modeling exercises should follow the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts*,[46] but that we, in consultation with the FLMs and States, should also publish additional guidance to address more recent issues such as particle speciation, emission rate averaging times, and "natural obscuration." Another State commenter said that The Guideline on Air Quality Models (CFR Part 51, Appendix W) should be included along with the IWAQM Report as a reference for CALPUFF setup. One RPO commented that we should provide data, perhaps using example facilities, to demonstrate the effect of the process so that States can get a better feeling for which sources are likely to fall below the 0.5 deciview threshold. This would help States understand the net effect of all of the parameters chosen in the exemption process.

Commenters also said that we should continuously revise modeling protocols by providing a modeling clearinghouse to States, and further, that we should consider new models for use, such as the Community Multiscale Air Quality (CMAQ) model.

There were specific comments requesting guidance for calculating visibility impacts and other general modeling concerns. One technical comment was that the guidelines should specify that the IMPROVE monitor is the receptor by which modeled visibility impacts should be evaluated with the CALPUFF model. Another commenter suggested using recent scientific evidence to update the light extinction coefficients used by CALPUFF to calculate visibility changes. These commenters also stated that CALPUFF might be improved by capping the relative humidity to lower values than are currently used.

Additional commenters representing utility organizations discussed how to identify Class I areas that should be modeled. They said that the guidelines should require sources to model only the nearest Class I area (or possibly the two closest), and one commenter said that we should provide a reasonable methodology to minimize the effort needed to address impacts from BART-eligible sources on multiple Class I areas.

Final Rule. We agree that States should adopt modeling protocols for all modeling demonstrations, regardless of the distance from the BART-eligible source and the Class I area impacted. We are therefore dropping the 200 km and greater distance requirement from the guidelines. As noted in the 2004 re-

[45] Guidance for *Estimating Natural Visibility Conditions Under the Regional Haze Rule*, U.S. Environmental Protection Agency, September 2003. *http://www.epa.gov/ttncaaa1/t1/memoranda/rh_envcurhr_gd.pdf.*

[46] *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts*, U.S. Environmental Protection Agency, EPA–454/R–98–019, December 1998.

proposal, we believe that potential uncertainties in model performance may be greater at distances greater than 200 km for a source. A modeling protocol may reduce the need for additional analyses. We favor coordination among States, EPA regions, RPOs, and other federal agencies to agree on a modeling protocol(s) which would provide consistent application.

In developing a modeling protocol, we also encourage States to use the framework provided for model setup in EPA's IWAQM. CALPUFF model users may find default settings in that document which may be appropriate for their modeling situations and add an element of consistency to model applications. *The Guideline on Air Quality Models* (CFR Part 51, Appendix W) also provides useful guidance.

We do, however, understand and agree that States have flexibility developing a modeling protocol. Moreover, the diversity of the nation's topography and climate, and variations in source configurations and operating characteristics, dictate against a strict modeling "cookbook". A State may need to address site-specific circumstances at individual sources potentially affecting a specific Class I area. For example, in a particular area a State may have available emissions data, that is more representative of the modeling domain, which may supplement the model defaults. States may want to consult with the appropriate EPA regional office and Federal Land Managers in adjusting the model input parameters. The modeling input recommendations in the IWAQM report are designed for visibility impact applications, and those defaults allow for tailoring for a given application (*e.g.* puff splitting). The model developers Web site[47] also has a series of frequently asked questions with answers to assist users in tailoring model applications.

We agree that we have only an advisory role in development of the protocol as the States better understand the BART-eligible source configurations and the geophysical and meteorological data affecting their particular Class I area(s).

In the protocol development process, we support the idea of designing example runs, as we have done in our example analysis for EGUs,[48] so that States may get a better understanding of what visibility impacts might be expected from a particular type of source or sources. Once a protocol has been finalized, a State may be able to use example runs as a proxy in making BART determinations which could potentially eliminate the need for case-by-case review for every BART-eligible source. A common sense approach should be taken, particularly where an analysis may add a significant resource burden to a State. For example, if there are multiple Class I areas in relatively close proximity to a BART-eligible source, a State may model a full field of receptors at the closest Class I area. Then a few strategic receptors may be added at the other Class I areas (perhaps at the closest point to the source, a receptor at the highest and lowest elevation in the Class I area, a receptor at the IMPROVE monitor, and a few receptors that are expected to be at the approximate plume release height). If the highest modeled impacts are observed at the nearest Class I area, a State may choose not to analyze the other Class I areas any further and additional analyses might be unwarranted.

As models are revised and advances in science are incorporated into the models, we can make certain that revisions to protocols are made accordingly. We will work closely with States and FLMs, as should States; we expect that States will also work closely with FLMs throughout the protocol development process. We expect a similar protocol development process for other models that may be used, once those models are developed to predict and track single source impacts and demonstrate acceptable model performance. States should contact the appropriate FLM and EPA regional office for the latest guidance and modeling updates.

Alternatives for Determining Visibility Impacts From Individual Sources

Background. In the 2004 reproposal, we requested comment on the following alternatives to CALPUFF modeling for determining whether individual sources cause or contribute to visibility impairment: look-up tables developed from screening-level air quality modeling; running CALPUFF in a simpler screening mode than the preferred approach; a source ranking methodology; and an emissions divided by distance (Q/D) method. Except for the simplified CALPUFF approach, all alternatives were based on developing a relationship between source emissions and the source's distance to a Class I area. Each of these approaches was intended to reduce the resource burden on States.

Comments. Some commenters supported the use of alternative approaches, while others suggested that the alternatives could be used either in conjunction, or in hierarchical fashion, with modeling approaches. Many commenters were opposed to their use. The opposing comments were consistent in stating that the alternatives were inappropriate because they did not account for important factors such as terrain, local meteorological data, prevailing wind directions (which influence pollutant transport), and differences in stack release parameters. Commenters added that there is no direct connection between emissions, distance, and visibility impairment, and that the methods treat SO_2 and NO_X equally for impairment estimates.

Final Rule. We disagree that the alternatives are necessarily inappropriate, but we share most of the concerns articulated by the opposing commenters. We believe that alternatives should not be used to exempt a source from BART review without more rigorous evaluations and sensitivity tests showing that the results are at least as conservative as the CALPUFF model. We know of at least one study showing that, for one location and for one year, there is no guarantee that the simplified CALPUFF technique is as conservative as the preferred approach[49]. While we are not adopting in the guideline any specific alternative to modeling for power plants greater than 750MW, a State may develop its own alternative approach for the other source categories to determine if a source would be subject to BART, provided that the alternative demonstrates a sufficient basis to determine clearly that the source causes or contributes to visibility impairment, or that more refined analysis is warranted. Use of an alternative approach could be a conservative non-modeling method for easing a State's resource burden. We believe conservatism is needed because of the purpose of the test: *i.e.* solely to determine if a closer look at the source is warranted.

E. The BART Determination Process

Background. CAA section 169A(g)(7) directs States to consider five factors in making BART determinations. The regional haze rule codified these factors in 40 CFR 51.308(e)(1)(ii)(B), which directs States to identify the "best system of continuous emissions control

[47] *http://www.src.com/calpuff/calpuff1.htm.*

[48] CALPUFF Analysis in Support of the June 2005 Changes to the Regional Haze Rule, U.S. Environmental Protection Agency, June 15, 2005, Docket No. OAR–2002–0076.

[49] Analysis of the CALMET/CALPUFF Modeling System in a Screening Mode, U.S. Environmental Protection Agency, November 1998, Docket No. OAR–2002–0076.

technology" taking into account "the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use at the source, and the remaining useful life of the source." Section IV. of the BART guidelines provides a step-by-step guide to conducting a BART determination which takes these factors into account.

This section of the preamble addresses a number of issues relative to the process for conducting a BART determination contained in Section IV of the BART guidelines.

1. What Is Meant by "Technical Feasibility of the Control Options" in Step 2 of the BART Determination?

Comments. We received several comments on this discussion, both on the 2001 proposal and on the 2004 reproposal. One commenter recommended that the concept of available technology for regional haze should be expanded to include those in the pilot scale testing phase, because these guidelines will precede the installation of controls by about 10 years. Other commenters believed that the discussion of technical feasibility introduced terms and concepts that were not clear, for example, what is meant by "commercial demonstration." One commenter raised issues with deeming technologies used in foreign countries "available" unless their performance has been demonstrated in the United States. A few commenters expressed concern with the provision in the guidelines that new technologies should be considered up to the time of a State's public comment period on the BART determination. The commenter believed that this could create an endless review loop for States if new technologies continually became available.

Final rule. In the final guidelines, we have largely retained the language that was in the proposed guidelines. Because the guidelines call for consideration of technologies that become available by the time of the State's public comment process on the BART determination, technologies should be considered that become available well after we finalize the BART guidelines. We also note, for clarity, that the Guidelines state that technologies need to be *both* licensed *and* commercially available (*i.e.* commercially demonstrated and sold).

2. How Should the Costs of Control Be Estimated in Step 4 of the BART Determination?

Comments. This section of the guidelines remained unchanged between the 2001 proposal and the 2004 reproposal. Comments varied, ranging from questioning the reliance on EPA's OAQPS Control Cost Manual Fifth Edition, February 1996, EPA 453/B–96–001 (hereafter called the "Control Cost Manual") to requesting that we not include the concept of incremental cost effectiveness in the guidelines. A commenter expressed concerns that incremental cost effectiveness calculations, the cost of implementing each succeeding control option, is too dependent on the number of interim options included in the analysis. Moreover, the commenter believed that incremental cost calculations increase the complexity of the analysis, and they also increase the possibility for inconsistent cost results.

Final rule. We have finalized this section of the guidelines with some changes to how it was proposed. States have flexibility in how they caculate costs. We believe that the Control Cost Manual provides a good reference tool for cost calculations, but if there are elements or sources that are not addressed by the Control Cost Manual or there are additional cost methods that could be used, we believe that these could serve as useful supplemental information.

In addition, the guidelines continue to include both average and incremental costs. We continue to believe that both average and incremental costs provide information useful for making control determinations. However, we believe that these techniques should not be misused. For example, a source may be faced with a choice between two available control devices, control A and control B, where control B achieves slightly greater emission reductions. The average cost (total annual cost/total annual emission reductions) for each may be deemed to be reasonable. However, the incremental cost (total annual $cost_{A-B}$/total annual emission $reductions_{A-B}$) of the additional emission reductions to be achieved by control B may be very great. In such an instance, it may be inappropriate to choose control B, based on its high incremental costs, even though its average cost may be considered reasonable.

Finally, it is important to note that, while BART determinations are focused at individual sources, it is likely that in response to SIP requirements, States will be making BART determinations for many units in a subject source category all at the same time. In doing so, States are likely to compare costs across each source category as well as looking at costs for individual units in order to respond to SIP requirements in an efficient manner (from the State's perspective).

3. How Should "Remaining Useful Life" Be Considered in Step 4 of the BART Determination?

Comments. We received a number of comments on the issue of remaining useful life, both on the 2001 proposal and on the 2004 reproposal. One commenter asserted that remaining useful life should not be considered in the cost analysis and that if a source is in operation at the time of a State's SIP submittal, it must have plans to install controls. Other commenters believed that, to the extent that assertions regarding a plant's remaining useful life influences the BART decision, there must be an enforceable requirement for the plant to shut down by that date. Other comments questioned whether Congress intended enforceable restrictions in order to take into account the remaining useful life and whether EPA had the authority under the CAA to require plant shutdowns.

A number of comments were received regarding our request for comments on how to provide flexibility for situations where market conditions change. Some comments interpreted this provision as a loophole that would allow sources to continue operation for a number of years without BART. Another comment supported the concept of allowing a source to later change its mind, so long as BART is installed.

Final rule. We have retained the approach in the proposed guidelines, including the provision for flexibility for sources to continue operating, with BART in place, should conditions change. We believe that the CAA mandates consideration of the remaining useful life as a separate factor, and that it is appropriate to consider in the analysis the effects of remaining useful life on costs. We believe that, because the source would not be allowed to operate after the 5-year point without such controls, the option for providing flexibility would not create a loophole for sources. Moreover, any source operating after this point without BART controls in place would be subject to enforcement actions for violating the BART limit. For any source that does not agree to shut down before the 5-year point, the State should identify a specific BART emission limit that would apply after this point in time.

4. How Should "Visibility Impacts" Be Considered in Step 5 of the BART Determination?

Background. The fifth statutory factor addresses the degree of improvement in visibility which may reasonably be anticipated to result from the use of the "best control technology" for sources subject to BART. The 2004 reproposal focuses on the use of single source emissions modeling to evaluate the BART control options. As part of the BART determination, we proposed that a State or individual source would run CALPUFF, or another EPA-approved model, to estimate, in deciviews, a BART source's visibility impact at a Class I area. The source would run the model once using its allowable emission rates, and then again at the various post-control emissions rates being evaluated for the BART determination. The 24-hour model results would then be tabulated for the pre- and post-control scenarios, for the average of the 20 percent worst modeled days at each receptor, over the time period of meteorology modeled. The difference in the averages for each receptor is the expected degree of improvement in visibility. Alternatively, the proposal requested comment on the option of using the hourly modeled impacts from CALPUFF at each receptor and determining the improvement in visibility based on the number of hours above the 0.5 deciview threshold for both the pre- and post-control model runs. We also requested comment on combinations of the proposed and alternative options and on the use of the simpler screening version of CALPUFF to do the analysis.

Comments. Several environmental groups said that issues relating to the determination of visibility improvement for evaluating BART controls are in many ways the same as for determining which BART-eligible sources are subject to BART. Thus, the commenter pointed out, the issues concerning the BART applicability test, discussed in section D., are all equally applicable here, including comments on: using the 0.5 deciview threshold on an aggregate basis for determining visibility impairment and potential exemption for BART-eligible sources, use of a natural visibility baseline versus current visibility, using a substantially lower deciview threshold than 0.5 deciviews to determine the contribution to visibility impairment by an individual source, and demonstration of those thresholds by means of appropriate modeling rather than other less reliable and more subjective techniques.

An industry commenter claimed that the American Corn Growers case emphasized the fact that the CAA clearly provides that BART determinations should balance the visibility benefits of controls comprehensively against their burdens; the commenter noted that this is not mentioned in our proposal; the commenter said that although the proposal would allow States to run the CALPUFF model, it fails to specify how they might consider the results.

One State commenter opposed the use of visibility modeling for the purpose of informing the choice of control option, stating that it is unnecessary, confusing and without adequate standards or guidance for implementation. The State added that the analysis of control options in the BART process should yield the greatest, most cost-effective control efficiency for NO_X and SO_2 at or above our presumptive levels of control. Moreover, it said that analysis of the degree of visibility improvement may result in very small increments of visibility improvements within Class I areas from an individual source, thus tilting the selection to the lower control efficiency option. The State added that we should remove this criterion from the analysis to ensure that the best cost effective controls will result. Another State agency said that modeling impacts should not be considered in BART determinations because they are not considered when determining BACT for the PSD program.

A variety of commenters pointed out several areas where the guidelines should be improved or clarified in regard to the degree of visibility improvement determination:

- We should clarify that the analysis is pollutant-specific (e.g., the modeling evaluation of a BART control option for SO_2 reduction should not be combined with the modeling evaluation of a BART control option for NO_X.)
- We should clarify that only the closest Class I area must be modeled.
- We should describe CALPUFF as one possible model to use, rather than as the only model that may be used.
- States and sources should have the flexibility to perform multiple modeling runs based on different levels of available control.
- Predicted visibility improvements that are imperceptible should be given no weight in determining the level of control that constitutes BART.
- States should be allowed to establish a factor for the required degree of visibility improvement.

Several industry and utility commenters expressed concern about using allowable emission rates to predict visibility impacts for BART control options; they argued that actual emission rates should be considered instead. Three commenters stated that we must make clear that States should use emission rates that will be permissible at the time BART controls take effect, not current emissions rates.

Additional comments from utilities, industry, and one State opposed the approach wherein the results from the 20 percent worst modeled days (pre- and post-control) were used to evaluate the visibility improvements expected from the various control options. Some believed this was too stringent, while others said it was not stringent enough. Two utilities added that the criteria should use the 20 percent worst days based on monitored data, not modeled data. An environmental group stated that sources should not be limited to just the worst days, but the improvements should be based upon controls reducing visibility impairment on any day. The commenter added that this rationale ignores the middle 60 percent of days in which visibility may worsen, because sources may increase emissions on these days as a trade-off for cutting emissions on the worst days. The commenter further argued that there are no data to support our assertion that improvement on the worst days means improvement on other days. They noted that default "natural condition" deciview values for Class I areas in our natural conditions guidance exist only for the average of the 20 percent best and worst days. The commenter added that we used the average default natural conditions (for the 20 percent best days) for the visibility impairment analysis, but there are no default "maximum 24-hour" values in the guidance.

Nine commenters supported implementation of visibility improvement thresholds, which were not proposed in 2004. A State commenter said it is unclear how the modeled net visibility improvement would be specifically utilized in the BART analysis, and requested a target level of improvement or a de minimis level by which to measure improvement. Two industry commenters suggested alternatives to the 24-hour value. One said that setting a threshold for comparison, as in the BART-applicability test, is more appropriate than the overall comparison of the 20 percent worst case days, and that the threshold for comparison should be on at least a daily average (or longer), not an hourly average, due to the possibility of short-term spikes based on certain meteorological conditions.

These commenters also said that a comparison of the number of days above or below a certain threshold is preferable since below a certain threshold, the impacts of visibility are not perceptible; unlike concentration levels of certain pollutants (*i.e.*, ozone) which do not have a threshold below which there are no effects, there are concentration levels of particulate below which there is no visibility impact. They also asserted that comparing the number of days would allow for a more complete picture of how controls would potentially improve visibility. As noted previously, a small number of unusual meteorological conditions can produce significant spikes on a single day or days. Since the overall goal of the regional haze rule is long-term visibility improvement, they said that a comparison of the total number of days exceeding a threshold over multiple years will provide a better overall indicator of visibility improvement. One commenter suggested that if we retain the maximum 24-hour value for the visibility impairment analysis, we should at least allow the use of only 1 year, rather than 5 years, of meteorological data. That would simplify the modeling and would lessen the chance that one day with atypical, extreme conditions would dictate the result.

One FLM supported our proposed method to determine visibility improvement associated with installation of BART. However, with regard to the use of hourly data instead of 24 hour data for the degree of visibility improvement assessment, another FLM said that while hourly model data are, by their nature, less reliable in predicting actual conditions, a measure that reports the total number of hours above a given threshold would still be a useful measure of the long-term effect of BART control. They said we should require States to report a combination of measures of the visibility improvement expected from BART. Such measures would be the change in the 20 percent worst days as well as a metric that examines the amount of time during a year that the source's visibility impact would exceed a threshold with and without BART.

Another utility commenter added that, if a BART control option would result in no perceptible improvement in visibility at a Class I area, then it is not a cost-effective option. This commenter said that based on Pitchford and Malm (1994)[50] and Henry (2002)[51] a 2 deciview threshold of perception would be appropriate, with a 1 deciview threshold providing a margin of safety. Another commenter said that we should clarify that visibility improvement differences among BART control options should be considered insignificant if the differences are less than the perceptibility threshold level, which should be set in excess of 1 deciview. Other commenters said the minimum threshold should be 1 deciview.

Final Rule. We disagree with the comment that modeling should not be part of a BART review because it is not considered for BACT. CAA section 169A(g)(2) clearly requires an evaluation of the expected degree of improvement in visibility from BART controls. All five statutory factors, including cost-effectiveness and expected visibility improvement, should be reflected in the level of BART control that the State implements. We believe that modeling, which provides model concentration estimates that are readily converted to deciviews, is the most efficient way to determine expected visibility improvement.

For the purposes of determining visibility improvement, States may evaluate visibility changes on a pollutant-specific basis. If expected improvement is shown from the various control choices, the State can weigh the results with the other four BART determination factors when establishing BART for a particular source. For example, a State can use the CALPUFF model to predict visibility impacts from an EGU in examining the option to control NO_X and SO_2 with SCR technology and a scrubber, respectively. A comparison of visibility impacts might then be made with a modeling scenario whereby NO_X is controlled by combustion controls. If expected visibility improvements are significantly different under one control scenario than under another, then a State may use that information, along with information on the other BART factors, to inform its BART determination.

Even though the visibility improvement from an individual source may not be perceptible, it should still be considered in setting BART because the contribution to haze may be significant relative to other source contributions in the Class I area. Thus, we disagree that the degree of improvement should be contingent upon perceptibility. Failing to consider less-than-perceptible contributions to visibility impairment would ignore the CAA's intent to have BART requirements apply to sources that contribute to, as well as cause, such impairment.

Although we are not requiring States to use allowable emission rates to predict the anticipated future visibility impacts of BART controls, we disagree that daily average actual emission rates should be used to make this assessment. Emissions from a source can vary widely on a day to day basis; during peak operating days, the 24-hour actual emission rate could be more than double the daily average. On the other hand, in the long term, estimating visibility impacts based on allowable emission rates for every hour of the year may unduly inflate the maximum 24 hour modeled impairment estimate from a BART-eligible source. The emissions estimates used in the models are intended to reflect steady-state operating conditions during periods of high capacity utilization. We do not generally recommend that emissions reflecting periods of start-up, shutdown, and malfunction be used, as such emission rates could produce higher than normal effects than would be typical of most facilities. Where States have information on a source's daily emissions, an emission rate based on the maximum actual emissions over a 24 hour period for the most recent five years may be a more appropriate gauge of a source's potential impact as it would ensure that peak emission conditions are reflected, but would likely not overestimate a source's potential impact on any given day. We have accordingly included this change to the final guidelines. We recommend that the State use the highest 24-hour average actual emission rate, for the most recent three or five year period of meteorological data, to characterize the maximum potential benefit.

Because each Class I area is unique, we believe States should have flexibility to assess visibility improvements due to BART controls by one or more methods, or by a combination of methods, and we agree with the commenters suggestions to do so. We believe the maximum 24-hour modeled impact can be an appropriate measure in determining the degree of visibility improvement expected from BART reductions (or for BART applicability). We have pointed out, however, that States should have flexibility when evaluating the fifth statutory factor. A State is encouraged to account for the magnitude, frequency, and duration of the contributions to visibility impairment caused by the source based on the natural variability of meteorology. These are important elements to consider as they would provide useful information on both the short term peak impact and long term average assessments which are critical in making the visibility assessment.

We agree with the suggestion that the use of a comparison threshold, as is

[50] Pitchford, M. and Malm, W., "Development and Applications of a Standard Visual Index," Atmospheric Environment, V. 28, no. 5, March 1994.

[51] Henry, R.C. "Just-Noticeable Differences in Atmospheric Haze", Journal of the Air & Waste Management Association, 52:1238–1243, October 2002.

done for determining if BART-eligible sources should be subject to a BART determination, is an appropriate way to evaluate visibility improvement. However, we believe the States have flexibility in setting absolute thresholds, target levels of improvement, or de minimis levels since the deciview improvement must be weighed among the five factors, and States are free to determine the weight and significance to be assigned to each factor. For example, a 0.3, 0.5, or even 1.0 deciview improvement may merit stronger weighting in one case versus another, so one "bright line" may not be appropriate.

In addition, comparison thresholds can be used in a number of ways in evaluating visibility improvement (e.g. the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, a threshold representing an x percent change in improvement, etc.). In our example modeling analysis of a hypothetical source,[52] we used three different 24-hour thresholds (1.0, 0.5, and 0.1 deciviews) and examined the number of days that those thresholds were exceeded for a source with a 90 percent change, for example, in SO_2 emissions (i.e. 10,000 TPY and 1,000 TPY). The number of days that the thresholds were exceeded in the 10,000 TPY case was substantial, and the visibility improvement due to the reduction in emissions was dramatic (i.e. the number of days exceeding the thresholds dropped considerably).[53]

Other ways that visibility improvement may be assessed to inform the control decisions would be to examine distributions of the daily impacts, determine if the time of year is important (e.g. high impacts are occurring during tourist season), consideration of the cost-effectiveness of visibility improvements (i.e. the cost per change in deciview), using the measures of deciview improvement identified by the State, or simply compare the worst case days for the pre- and post-control runs. States may develop other methods as well.

5. In What Sequence Should Alternatives Be Assessed in Step 5 of the BART Determination?

Background. Both the 2001 proposal and the 2004 reproposal requested comments on two options for evaluating the ranked options. Under the first option, States would use a sequential process for conducting the impacts analysis, beginning with a complete evaluation of the most stringent control option. If a State determines that the most stringent alternative in the ranking does not impose unreasonable costs of compliance, taking into account both average and incremental costs, the analysis begins with a presumption that this level is selected. Under this option, States would then proceed to consider whether energy and non-air quality environmental impacts would justify selection of an alternative control option. If there are no outstanding issues regarding energy and non-air quality environmental impacts, the analysis is ended and the most stringent alternative is identified as the "best system of continuous emission reduction." If a State determines that the most stringent alternative is unacceptable due to such impacts, this approach would require them to document the rationale for this finding for the public record. Then, the next most-effective alternative in the listing becomes the new control candidate and is similarly evaluated. This process would continue until the State identifies a technology which does not pose unacceptable costs of compliance, energy and/or non-air quality environmental impacts.

We also requested comment on an alternative decision-making approach that would not begin with an evaluation of the most stringent control option. For example, States could choose to begin the BART determination process by evaluating the least stringent technically feasible control option or by evaluating an intermediate control option drawn from the range of technically feasible control alternatives. Under this approach, States would then consider the additional emissions reductions, costs, and other effects (if any) of successively more stringent control options. Under such an approach, States would still be required to (1) display all of the options and identify the average and incremental costs of each option; (2) consider the energy and non-air quality environmental impacts of each option; and (3) provide a justification for adopting the technology selected as the "best" level of control, including an explanation of its decision to reject the other control technologies identified in the BART determination.

In selecting a "best" alternative, the proposed guidelines included a discussion on whether the affordability of controls should be considered. As a general matter, for plants that are essentially uncontrolled at present and emit at much greater levels per unit of production than other plants in the category, we believe it is likely that additional control will be cost-effective. The proposed guidelines noted, however, that we recognize there may be unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology. These effects would include effects on product prices, the market share, and profitability of the source. We did not intend, for example, that the most stringent alternative must always be selected if that level would cause a plant to shut down, while a slightly lesser degree of control would not have this effect.

Comments. We received comments supporting both of the approaches for evaluating ranked control alternatives. Many commenters, including commenters from State agencies, were supportive of the first approach. Comments from State air quality agencies were strongly supportive of this approach. These commenters believed that this approach is consistent with past approaches by States for considering control options for case-by-case determinations, is well understood by all parties, and thus easier to implement. The first approach also was strongly supported in comments from environmental organizations and private citizens. Some comments noted that the plain terminology "best" suggests that there must be a sound reason for not using the most stringent control level.

Many comments from industrial trade organizations were critical of the first approach and believed that any requirement to use this approach would reduce State discretion because this approach, in the judgment of the commenters, would amount to use of the most stringent alternative as a default. Some of these comments asserted that the approach in option 1 would shift the BART analysis away from a cost-benefit approach mandated by the CAA towards a BACT-like technology analysis. Other commenters believed that EPA should recognize that BART, as a control requirement for retrofitting existing sources, should differ from BACT or other controls for new equipment. A number of comments, in supporting the second approach, believed that this approach provides greater consideration of the incremental cost of each succeeding option.

Final rule. In the final guidelines, we have decided that States should retain the discretion to evaluate control options in whatever order they choose, so long as the State explains its analysis of the CAA factors. We agree with

[52] CALPUFF Analysis in Support of the June 2005 Changes to the Regional Haze Rule, U.S. Environmental Protection Agency, June 15, 2005, Docket No. OAR–2002–0076.

[53] Ibid.

commenters who asserted that the method for assessing BART controls for existing sources should consider all of the statutory factors.

6. What Should Be the Presumptive Limits for SO_2 and NO_X for Utility Boilers?

Background. In the 2004 reproposal, we proposed that States, as a general matter, should require EGUs greater than 250 MW in size at power plants larger than 750 MW to control 95 percent of their SO_2 emissions, or control to within an SO_2 emission range of 0.1 to 0.15 lb/mmBtu. We also proposed to establish a rebuttable presumption that States should impose these BART SO_2 limits on all EGUs greater than 250 MW, regardless of the size of the power plant at which they are located.

For NO_X, we proposed that sources currently using controls such as SCRs to reduce NO_X emissions during part of the year should be required to operate those controls year-round. For power plants without post-combustion controls, we proposed to establish a presumptive emissions limit of 0.20 lbs/mmbtu for EGUs greater than 250 MW in size. We requested comment on the rate of NO_X emissions that can be achieved with combustion modifications on specific types of boilers. Many commenters responded both in favor and in opposition to these proposed BART presumptive limits.

Comments. A number of utility groups said the presumptive SO_2 emissions control approach inappropriately ignores the need for a visibility impact evaluation which is required in step 5 of the proposed case-by-case BART engineering analysis. They said that setting presumptive limits infringes on a state's authority to establish BART on a case-by-case basis considering not only visibility improvement, but the other statutory factors as well. The commenters said that visibility is both Class I area and source specific, which is the reason Congress gave the States the lead role and discretion in the BART program to determine which sources need to install or upgrade controls. Through the use of presumptions and default values, however, our prescriptive process, as proposed, would make the installation of maximum controls more likely without regard to visibility benefits. Instead, they argued, we should give the states maximum flexibility to use the five statutory factors in their BART determinations. Commenters said sources must be allowed to assess the visibility improvements of a variety of control options.

Several utilities raised concern that sources with existing controls should not be required to meet the presumptive limits without the chance to evaluate the degree of visibility improvement expected from the additional emission reduction requirements. They said that if a source can demonstrate a reduction in visibility impairment below the specified threshold (whether that threshold is our currently proposed 0.5 deciview or an alternative level) with less stringent controls, then neither we nor States should impose, by default, more stringent reduction requirements.

Commenters from industry, utilities, and States said that we had not indicated what previously-controlled sources must do to comply with BART, while we had determined what controls are necessary for uncontrolled sources. They were concerned that the guidelines would lead States to require previously-controlled sources to remove the controls and replace them with even newer controls at great cost and very little, if any, improvement in emission levels and visibility in Class I areas. Commenters added that States should be able to use their discretion to determine whether additional controls are needed.

Some commenters were concerned that the proposed rule would require some plants to install SCR to meet the NO_X control level proposed, as the potential retrofit of SCR technology for the BART determination may be supported by the degree of visibility improvement expected. They said that the guidelines indicate that if a State finds that a source's visibility contribution warrants the installation of SCR, then SCR may be imposed. The commenter added, however, that the guidelines also need to provide for instances where the visibility condition warrants a lesser control level than what would be achieved by advanced combustion control; the commenter claimed there was reference to this concept in the preamble but not the guidelines.

Final rule. In these guidelines, we are finalizing specific presumptive limits for SO_2 and NO_X for certain EGUs based on fuel type, unit size, cost effectiveness, and the presence or absence of pre-existing controls. The presumptive limits finalized in today's rulemaking reflect highly cost-effective technologies as well as provide enough flexibility for States to take particular circumstances into account.

The presumptive limits apply to EGUs at power plants with a total generating capacity in excess of 750 MW. As explained in greater detail below, for these sources we are establishing a BART presumptive emission limit for coal-fired EGUs greater than 200 MW in size without existing SO_2 control. These EGUs should achieve either 95 percent SO_2 removal, or an emission rate of 0.15 lb SO_2/mmBtu, unless a State determines that an alternative control level is justified based on a careful consideration of the statutory factors. For NO_X, we are establishing a set of BART presumptive emission limits for coal-fired EGUs greater than 200 MW in size based upon boiler size and coal type, and based upon whether selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR) are already employed at the source. See section d. below for a table listing those specific limits. Based on our analysis of emissions from power plants, we believe that applying these highly cost-effective controls at the large power plants covered by the guidelines would result in significant improvements in visibility and help to ensure reasonable progress toward the national visibility goal.

States, as a general matter, must require owners and operators of greater than 750 MW power plants to meet these BART emission limits. We are establishing these requirements based on the consideration of certain factors discussed below. Although we believe that these requirements are extremely likely to be appropriate for all greater than 750 MW power plants subject to BART, a State may establish different requirements if the State can demonstrate that an alternative determination is justified based on a consideration of the five statutory factors.

In addition, while States are not required to follow these guidelines for EGUs located at power plants with a generating capacity of less than 750 MW, based on our analysis detailed below, we believe that States will find these same presumptive controls to be highly-cost effective, and to result in a significant degree of visibility improvement, for most EGUs greater than 200 MW, regardless of the size of the plant at which they are located. A State is free to reach a different conclusion if the State believes that an alternative determination is justified based on a consideration of the five statutory factors. Nevertheless, our analysis indicates that these controls are likely to be among the most cost-effective controls available for any source subject to BART, and that they are likely to result in a significant degree of visibility improvement.

The rest of this section discusses these presumptive limits for SO_2 and NO_X for EGUs and the additional visibility impact and cost-effectiveness analyses we have performed since proposal of the guidelines in 2004.

a. Visibility Analysis for SO_2 and NO_X Emissions From EGUs. In the 2004 reproposal, our preliminary CALPUFF modeling[54] suggested that controlling a single 250 MW EGU at a 90 percent level would improve visibility substantially from that source. Based on the expected degree of improvement in visibility and the use of highly effective control technologies that are available for sources of this capacity and greater, we concluded that the specific control levels in the proposal were appropriate. Even at that level of control however, our analysis indicated that emissions from the source might still cause a perceptible impact on visibility.

Following comments that we had ignored the need to consider the degree of improvement in visibility which could reasonably be anticipated from the use of the presumptive control technologies, we undertook a more comprehensive modeling analysis of the anticipated visibility impacts of controlling large EGUs. Based on this modeling analysis, we anticipate that a majority of the currently uncontrolled EGUs at power plants covered by the guideline are predicted to have 24-hour maximum impacts of greater than a change of 2 or 3 deciviews.[55] Our modeling examples included scenarios that were representative of typical EGUs, but, in our first hypothetical run #1, we conservatively assumed SO_2 emissions of 10,000 tons per year (TPY) and NO_X *emissions of approximately* 3,500 TPY.[56] Such levels of emissions are well below those that may be expected of an uncontrolled 200 MW EGU. The number of days during any year that such sources are predicted to have visibility impacts of greater than 0.5 deciviews or even 1.0 deciview were 29 days and 12 days on average, respectively, at 50 km from a hypothetical Class I area in the East; if the 98th percentile were considered, there would be five days above a 1.0 deciview change.

The modeled emission rates in the example were conservative; for much larger EGUs with capacities of 750 MW or more, and emission rates much higher than those which were modeled, visibility degradation is expected to be far worse. Clearly there is a substantial degree of visibility improvement which is likely from emission reductions at these sources.

Although we are confident that the EGUs for which we are establishing presumptive limits each have a significant impact on visibility at one or more Class I areas, a State retains the option and flexibility to conduct its own analysis or allow a source to demonstrate that it should not be subject to BART (based on its visibility effects).

b. BART Presumptive Limits for SO_2 From Coal-Fired Units. For currently uncontrolled coal-fired EGUs greater than 200 MW in size located at power plants greater than 750 MW, we are establishing a presumptive BART limits of 95 percent SO_2 removal, or an emission rate of 0.15 lb SO_2/mmBtu. We are not establishing a presumptive limit for EGUs with existing post-combustion SO_2 controls or for EGUs that burn oil.

In 2004, we proposed presumptive limits for SO_2 of 95 percent control or a comparable performance level of 0.1 to 0.15 lbs per million BTU as controls that would be achievable and cost-effective. We requested comment on the removal effectiveness of flue gas desulfurization ("FGD" or "scrubber" controls) for various coal types and sulfur content combinations. Having considered the comments received, we have determined that there is ample data to support the determination that the BART presumptive limits outlined in today's action are readily achievable by *new wet or semi-dry FGD systems* across a wide range of coal types and sulfur contents based on proven scrubber technologies currently operational in the electric industry.[57]

We agree with the commenters who stated that our dual recommendation provided equity across sources burning coals of varying sulfur content. We believe the presumptive limits provide enough flexibility that absent unique circumstances, any BART-eligible coal-fired EGU will be able to achieve one of the limits with a new FGD system. We expect that BART-eligible EGUs burning medium to high sulfur coal will be able to achieve a removal efficiency of 95 percent in a cost effective manner by utilizing various wet FGD technologies, and that those EGUs burning lower sulfur coals could meet the emission limit of 0.15lb/mmBtu in a cost effective manner by utilizing dry FGD technologies. As described below, EPA's unit specific economic modeling showed that the majority of BART eligible units greater than 200 MW can meet the presumptive BART limit at a cost of $400 to $2000 per ton of SO_2 removed.

Some commenters expressed concerns that the proposed limits were too stringent in particular for: (1) EGUs less than 750 MW in size, (2) EGUs burning low sulfur coals, and (3) EGUs burning lignite coals. However, numerous examples exist of smaller EGUs and EGUs burning low sulfur or lignite coals achieving these SO_2 limits at reasonable cost.[58] We recognize that semi-dry FGD systems are most commonly utilized on units burning lower sulfur coals and are not typically designed for removal efficiencies of 95 percent or greater. However, we believe that most of these EGUs can readily achieve the presumptive emission rate limit of 0.15 lb SO_2/mmBtu. An analysis of EPA's RACT/BACT/LEAR Clearinghouse Dry FGD cost effectiveness data ranged from $393 to $2132 per ton SO_2 removed, with an average cost effectiveness of $792 per ton.[59]

We received a few comments expressing the belief that the presumptive limits should be more stringent, given that BART emission limits will not be fully implemented until 2013 or 2014. We recognize that while some scrubber units currently achieve reductions greater than 95 percent, not all units can do so. The individual units that currently achieve greater than 95 percent control efficiencies do not necessarily represent the wide range of unit types across the universe of BART-eligible sources. An analysis of the Department of Energy's U.S. FGD Installation Database supports our belief that 95 percent removal efficiencies would be obtainable by all types of EGUs burning medium and high sulfur coal by 2014, including BART-eligible EGUs. In addition, we note that the presumption does not limit the States' ability to consider whether a different level of control is appropriate in a particular case. If, upon examination of an individual EGU, a State determines that a different emission limit is appropriate based upon its analysis of the five factors, then the State may apply a more or less stringent limit.

Our analysis of presumptive BART limits accounted for variations in existing SO_2 controls. We accordingly considered (1) coal-fired EGUs without

[54] *Summary of Technical Analyses for the Proposed Rule,* Mark Evangelista, U.S. Environmental Protection Agency, April 12, 2004, Docket No. OAR–2002–0076.

[55] CALPUFF Analysis in Support of the the June 2005 Changes to the Regional Haze Rule, U.S. Environmental Protection Agency, June 15, 2005, Docket No. OAR–2002–0076.

[56] *Ibid.*

[57] *Technical Support Document for BART SO_2 Limits for Electric Generating Units,* Memorandum to Docket OAR 2002–0076, April 1, 2005.

[58] Ibid.

[59] *Summary of BART Source Analyses,* Memorandum from Bill Balcke and Doran Stegura, Perrin Quarles Associates, Inc., to Chad Whiteman, EPA March 24, 2003. See 2001 emissions data in BART AR file, attached.

existing SO_2 controls, and (2) coal-fired EGUs with existing SO_2 controls. This analysis consisted of the following key elements: (1) Identification of all potentially BART-eligible EGUs, and (2) technical analyses and industry research to determine applicable and appropriate SO_2 control options, (3) economic analysis to determine cost effectiveness for each potentially BART-eligible EGU, and (4) evaluation of historical emissions and forecast emission reductions for each potentially BART-eligible EGU.[60]

We identified 491 potentially BART-eligible coal-fired units based on the following criteria: (1) The unit was put in place between August 7, 1962 and August 7, 1977, and (2) the unit had the potential to emit more than 250 tons annually of SO_2. Our assessment of potential controls included various industry case studies, technical papers, public comments, BACT analyses, and historical Acid Rain emissions data. Our analysis is described in detail in the TSD.[61]

We calculated cost effectiveness and projected SO_2 emission reductions on a per unit basis based on removal efficiencies of 90 percent for dry FGD systems, in particular spray dry lime systems, and 95 percent for wet FGD systems, in particular limestone forced oxidation systems. Based on our analysis, the average cost effectiveness for controlling all BART-eligible EGUs greater than 200 MW without existing SO_2 controls was estimated to $919 per ton of SO_2 removed. Moreover, the range of costs effectiveness numbers demonstrates that the majority of these units can meet the presumptive limits at a cost of $400 to $2000 per ton of SO_2 removed.

FIGURE 1

Unit capacity (MW)	Tons (K) of SO_2 emitted in 2001	Percent of BART eligible coal-fired unit's 2001 emissions	Calculated average cost effectiveness for MW grouping ($/ton SO_2 removed)	Percent of estimated removable BART SO_2 emissions from coal-fired units*
<50 MW	26	0.4	1962	0.9
50–100 MW	93	1.4	2399	1.6
100–150 MW	171	2.5	1796	2.2
150–200 MW	235	3.5	1324	3.4
200–250 MW	253	3.8	1282	3.1
250–300 MW	281	3.2	1128	4.0
>300 MW	5712	85.2		84.8
All Units	6707	100	984	100
BART Units (>200MW)	6246	92.2	919	91.9

In establishing presumptive BART limits, we were cognizant of the fact that upgrading an existing scrubber system is typically considered more cost effective than constructing a new scrubber system. However, due to the diverse and complex nature of upgrading existing FGD systems (scrubber type, reagents, online year, absorber characteristics, current operating procedures, etc.), there is no single solution or standard appropriate for all EGUs. As a result, we are not including specific numerical presumptive limits for EGUs with pre-existing scrubbers. However, for scrubbers currently achieving removal efficiencies of at least 50 percent, we recommend States evaluate a range of scrubber upgrade options available for improving the SO_2 removal performance of existing units. There are numerous scrubber enhancements available to upgrade the average removal efficiencies of all types of existing scrubber systems, and the guidelines contains a discussion of the options that States should evaluate in making BART determinations for EGUs with existing scrubbers.

The guidelines do not require EGUs with existing FGD systems to remove these controls and replace them with new controls, but the guidelines do state that coal fired EGUs with existing SO_2 controls achieving removal efficiencies of less than 50 percent should consider constructing a new FGD system to meet the presumptive limits of 95 percent removal or 0.15 lb/mmBtu in addition to evaluating the suite of upgrade options. For these EGUs, the suite of available "upgrades" may not be sufficient to remove significant SO_2 emissions in a cost effective manner, and States may determine that these EGUs should be retrofitted with new FGD systems.

c. BART Limits for SO_2 From Oil-Fired Units. We are not establishing a presumptive BART limit for SO_2 from oil-fired EGUs. The guidelines state that the most appropriate control option for oil-fired EGUs, regardless of capacity, is to set limits on the sulfur content of the fuel oil burned in the unit.

Commenters suggested EPA evaluate two primary control options for BART oil-burning units: (1) Sulfur content fuel oil limitations, and (2) flue gas desulfurization systems. We have been unable to find any FGD application in the U.S. electric industry on an oil-fired unit. As a result, our analysis for oil-fired units focused on benchmarking previously imposed fuel oil restrictions on the electric industry and (2) a regional economic analysis of switching from high sulfur to low sulfur fuel oil.

Our study of currently imposed fuel oil restrictions on the electric industry suggested that all BART-eligible EGUs currently have some sort of imposed sulfur content or emission rate limitation. Of the 74 BART-eligible oil-burning EGUs, 32 currently have sulfur fuel oil restrictions of less than 1 percent, and 67 have some sort of sulfur content limitation. In addition, our economic analysis suggests that switching to low sulfur fuel oil is a cost effective method in reducing SO_2 emission from oil fired units.

As approximately 43 percent of the BART eligible oil units currently have a sulfur content limitation that is either equivalent to, or more stringent than, one percent sulfur by weight, the guidelines require States to consider a one percent or lower sulfur by weight fuel oil restriction on all BART eligible EGUs as part of their BART analysis, and recommends that States establish appropriate and sustainable sulfur content fuel oil restrictions, taking into

[60] Ibid.

[61] Ibid.

account fuel oil availability. States should accordingly evaluate a one percent sulfur content limitation as a starting point of their BART determination for oil-fired EGUs subject to BART.

d. BART Presumptive Limits for NO_X From Coal-fired Units. In the 2004 reproposal, in discussing NO_X controls on EGUs, we explained that there are two somewhat distinct approaches to reducing emissions of NO_X at existing sources. One is to use combustion controls (including careful control of combustion air and low-NO_X burners). The other approach is removal technology applied to the flue gas stream (such as SCRs and SNCRs).

For EGUs currently using controls such as SCRs or SNCRs to reduce NO_X during part of the year, we are establishing a presumption that use of these same controls year-round is BART. (Some commenters supported year-round operation of these controls. One commenter suggested the cost of year-round operation of SCRs would be significant. However, our analysis showed year-round operation of existing SCRs compared to operation during the 5-month ozone season only to be highly cost effective (average cost-effectiveness of $170 per ton).) Although only a few BART-eligible sources currently have SNCRs installed, we note that States may wish to consider SCR as an alternative to annual operation of SNCR in light of the relatively high operating costs associated with SNCR.

For sources without post-combustion controls (*i.e.*, SCRs and SNCRs), we are establishing a presumption as to the appropriate BART limits for coal-fired units based on boiler design and coal type. These presumptions apply to EGUs greater than 200 MW at power plants with a generating capacity greater than 750 MW and are based on control strategies that are generally cost-effective for all such units.

In 2004 we noted that, unlike the methods for controlling SO_2 (which fall within a fairly narrow range of cost effectiveness and control efficiencies), the removal efficiencies and costs associated with the control techniques for NO_X vary considerably, depending on the design of the boiler and the type of coal used. In response to comments on the proposal, we have performed additional analyses of all individual BART-eligible coal-fired units [62] and our analyses indicated that both cost effectiveness and post-control rates for NO_X do depend largely on boiler design and type of coal burned. Based on these analyses, we believe that States should carefully consider the specific NO_X rate limits for different categories of coal-fired utility units, differentiated by boiler design and type of coal burned, set forth below as likely BART limits.

In today's action, EPA is setting presumptive NO_X limits for EGUs larger than 750 MW. EPA's analysis indicates that the large majority of the units can meet these presumptive limits at relatively low costs. Because of differences in individual boilers, however, there may be situations where the use of such controls would not be technically feasible and/or cost-effective. For example, certain boilers may lack adequate space between the burners and before the furnace exit to allow for the installation of over-fire air controls. Our presumption accordingly may not be appropriate for all sources. As noted, the NO_X limits set forth here today are presumptions only; in making a BART determination, States have the ability to consider the specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source.

The table below indicates the types of boilers installed at the 491 BART-eligible coal-fired EGUs. Dry-bottom wall-fired boiler units and tangentially-fired boiler units make up a large majority of the total BART-eligible EGUs.

TABLE 1.—POPULATION OF BART-ELIGIBLE COAL-FIRED EGUS

Boiler type	Number	Number	Number
	All units	Units > 200 MW	Units > 200 MW at 750 MW plants
Cyclone	56	35	19
Cell Burner	35	35	29
Dry Bottom—Wall fired	188	121	77
Dry Bottom Turbo-fired	14	10	4
Stoker	5	0	0
Tangentially-fired	186	164	112
Wet Bottom	6	5	5
Other	1	0	0
Total BART-eligible coal-fired EGUs	491	370	246

For all types of boilers other than cyclone units, the limits in Table 2 are based on the use of current combustion control technology. Current combustion control technology is generally, but not always, more cost-effective than post-combustion controls such as SCRs. For cyclone boilers, SCRs were found to be more cost-effective than current combustion control technology;[63] thus the NO_X limits for cyclone units are set based on using SCRs. SNCRs are generally not cost-effective except in very limited applications and therefore were not included in EPA's analysis. The types of current combustion control technology options assumed include low NO_X burners, over-fire air, and coal reburning.

We are establishing presumptive NO_X limits in the guidelines that we have determined are cost-effective for most units for the different categories of units below, based on our analysis of the expected costs and performance of controls on BART-eligible units greater than 200 MW. We assumed that coal-fired EGUs would have space available to install separated over-fire air. Based on the large number of units of various boiler designs that have installed separated over-fire air, we believe this assumption to be reasonable. It is

[62] See *Technical Support Document for BART NO_X Limits for Electric Generating Units* and Technical Support Document for BART NO_X Limits for Electric Generating Units Excel Spreadsheet, Memorandum to Docket OAR 2002–0076, April 15, 2005.

[63] The current combustion control technology EPA analyzed for cyclone units is coal reburning.

possible, however, that some EGUs may not have adequate space available. In such cases, other NO_X combustion control technologies could be considered such as Rotating Opposed Fire Air ("ROFA"). The limits provided were chosen at levels that approximately 75 percent of the units could achieve with current combustion control technology. The costs of such controls in most cases range from just over $100 to $1000 per ton. Based on our analysis, however, we concluded that approximately 25 percent of the units could not meet these limits with current combustion control technology. However, our analysis indicates that all but a very few of these units could meet the presumptive limits using advanced combustion controls such as rotating opposed fire air ("ROFA"), which has already been demonstrated on a variety of coal-fired units. Based on the data before us, the costs of such controls in most cases are less than $1500 per ton.

TABLE 2.—PRESUMPTIVE NO_X EMISSION LIMITS FOR BART-ELIGIBLE COAL-FIRED UNITS[64]

Unit type	Coal type	NO_X presumptive limit (lb/mmbtu)[65]
Dry-bottom wall-fired	Bituminous	0.39
	Sub-bituminous	0.23
	Lignite	0.29
Tangential-fired	Bituminous	0.28
	Sub-bituminous	0.15
	Lignite	0.17
Cell Burners	Bituminous	0.40
	Sub-bituminous	0.45
Dry-turbo-fired	Bituminous	0.32
	Sub-bituminous	0.23
Wet-bottom tangential-fired	Bituminous	0.62

TABLE 3.—AVERAGE COST-EFFECTIVENESS OF NO_X CONTROLS FOR BART-ELIGIBLE COAL-FIRED UNITS

Unit type	Coal type	Number units nation-wide	National average ($/ton)
Dry-bottom wall-fired	Bituminous	114	1229
	Sub-bituminous	66	576
	Lignite	3	1296
Tangential-fired	Bituminous	105	567
	Sub-bituminous	72	281
	Lignite	9	614
Cell Burners	Bituminous	32	1287
	Sub-bituminous	3	1021
Dry-turbo-fired	Bituminous	7	775
	Sub-bituminous	7	599
Wet-bottom	Bituminous	6	378
Cyclones (with SCR)	All	56	900

The advanced combustion control technology we used in our analysis, ROFA, is recently available and has been demonstrated on a variety of unit types. It can achieve significantly lower NO_X emission rates than conventional over-fire air and has been installed on a variety of coal-fired units including T-fired and wall-fired units. We expect that not only will sources have gained experience with and improved the performance of the ROFA technology by the time units are required to comply with any BART requirements, but that more refinements in combustion control technologies will likely have been developed by that time. As a result, we believe our analysis and conclusions regarding NO_X limits are conservative.[66] For those units that cannot meet the presumptive limits using current combustion control technology, States should carefully consider the use of advanced combustion controls such as ROFA in their BART determination.

A detailed discussion of our analysis is in the docket.[67] For data on emissions and existing control technology in use at the BART-eligible EGUs, we used EPA's Clean Air Markets Division database.[68]

C. Selective Catalytic Reduction ("SCR") and Cyclone Units

We also analyzed the installation of SCRs at BART-eligible EGUs, applying SCR to each unit and fuel type. The cost-effectiveness was generally higher than for current combustion control technology except for one unit type, cyclone units. Because of the relatively high NO_X emission rates of cyclone units, SCR is more cost-effective. Our analysis indicated that the cost-effectiveness of applying SCR on coal-fired cyclone units is typically less than $1500 a ton, and that the average cost-

[64] No Cell burners, dry-turbo-fired units, nor wet-bottom units burning lignite were identified as BART-eligible, thus no presumptive limit was determined. Similarly, no wet-bottom units burning sub-bituminous were identified as BART-eligible.

[65] These limits reflect the design and technological assumptions discussed in the technical support document for NO_X limits for these guidelines, *e.g.*, EPA assumed space would be available for over-fire air. See *Technical Support Document for BART NO_X Limits for Electric Generating Units* and *Technical Support Document for BART NO_X Limits for Electric Generating Units Excel Spreadsheet*, Memorandum to Docket OAR 2002–0076, April 15, 2005.

[66] See *Technical Support Document for BART NO_X Limits for Electric Generating Units and Technical Support Document for BART NO_X Limits for Electric Generating Units Excel Spreadsheet*, Memorandum to Docket OAR 2002–0076, April 15, 2005.

[67] Id.

[68] Reporting requirements for the Acid Rain Program and NO_X SIP Call affected sources, see 40 CFR 75 subpart G (parts 7562–64), and EPA Clean Air Markets Division Web site, data and maps page *(http://www.epa.gov/airmarkets)*.

effectiveness is $900 per ton.[69] As a result, we are establishing a presumptive NO_X limit for cyclone units based on the use of SCR. For other units, we are not establishing presumptive limits based on the installation of SCR. Although States may in specific cases find that the use of SCR is appropriate, we have not determined that SCR is generally cost-effective for BART across unit types.

Oil and Gas-Fired Units

For oil-fired and gas-fired units, we believe that installation of current combustion control technology is highly cost-effective and should be considered in determining BART for these sources. We performed an analysis of BART-eligible oil and gas-fired units similar to the analysis done for coal-fired units. Our analysis indicated that a number of units can make significant reductions in NO_X emissions which are cost-effective through the application of current combustion control technology.[70] However, for a number of units, the use of combustion controls does not appear to be cost-effective. As a result, we determined that it would be inappropriate to establish a general presumption regarding likely BART limits. As a result, the guidelines only indicate that States should consider the installation of current combustion control technology on oil and gas-fired units.

IV. How Does Today's Rule Affect States Options for Using Alternative Strategies in Lieu of Source-by-Source BART?

Background

Over the past several years, there have been a number of rule makings and court decisions on the subject of BART and BART-alternative programs. In order to understand today's actions, it is useful to again review the regulatory and litigation history, with a specific focus on BART-alternative issues.

As noted in part I of this preamble, the 1999 regional haze rule included provisions for BART, codified at 40 CFR 51.308(e), and in definitions that appear in 40 CFR 51.301. Among these provisions was section 308(e)(2), allowing States to implement cap and trade programs, or other alternative programs, in lieu of BART. Section 308(e)(2) provided that trading program alternatives must be demonstrated to achieve greater reasonable progress than BART, and provided the general parameters for making this demonstration. Of particular relevance, section 308(e)(2) directed States, in the course of estimating emissions reductions anticipated from source-by-source BART, to determine what comprises BART based on the four non-visibility factors, and then estimate visibility improvements based on the application of BART to all sources subject to BART. In other words, section 308(e)(2) indicated that states should use what has since been termed a "group BART" approach to estimating the source-by-source BART benchmark, for comparison to the alternative program. Section (e)(2) did not prescribe the specific criteria to be used to compare the progress estimated from source-by-source BART to that anticipated from the trading program. The preamble discussion indicated that the comparison should be based on both emission reductions and visibility improvement, but did not provide further specificity. See 64 FR at 35741–35743.

Specific criteria for making the comparison to programs was proposed in the BART Guidelines (40 CFR 51 App. Y) in 2001. These criteria—sometimes referred to as the "better-than-BART test" consist of the following. First, if the geographic distribution of emissions reductions from the two programs is expected to be similar, the comparison can be made based on emissions alone. Second, if the distribution of emissions reductions is anticipated to be significantly different, then a two-pronged visibility improvement test is employed. The first prong is that the alternative program must not result in a degradation of visibility at any Class I area. The second prong is that the alternative program must result in greater visibility improvement overall, based on an average across all affected Class I areas. See 66 FR 38133.

In 2002, the D.C. Circuit decided American Corn Growers. The court in that decision invalidated "the BART provisions" on the basis that EPA had improperly constrained State authority by requiring them to bifurcate visibility from the other statutory factors when making BART determinations, and by specifying that visibility impairment should be considered on a group basis when determining whether a BART eligible source is subject to BART. 291 F.3d 1, 8.

Because EPA's policy of allowing alternative programs to BART was not at issue in American Corn Growers, the decision contained no discussion of how such alternative programs would be compared to BART—neither the step of estimating emissions from source-by-source BART, nor the criteria for the actual comparison (*i.e.*, the test). Therefore, EPA interpreted the court's vacature of the BART provisions to apply to the source-by-source BART regulations under 40 CFR 51.308(e)(1). Accordingly, in our May 2004 reproposal of the BART guidelines, we did not propose any changes in section 308(e)(2), and we retained the section on trading programs in the guidelines (Appendix Y) as that section was proposed in 2001.

In June 2004, in the Supplemental Notice of Proposed Rulemaking (SNPR) for the Clean Air Interstate Rule (CAIR), we proposed to conclude that the CAIR will achieve greater reasonable progress than would BART for SO_2 and NO_X at BART-eligible EGUs in CAIR affected States and therefore may be treated as a program in lieu of BART for those sources. In doing so, we discussed regional haze rule section 308(e)(2) as precedent for the policy of allowing trading programs to substitute for BART.[71] However, noting that the CAIR trading program affected only one category of BART-eligible sources (EGUs), rather than all BART-eligible categories as envisioned for State-developed BART-alternative programs under section 308(e)(2), we proposed adding a 308(e)(3) applicable only to CAIR. This section would provide that states that comply with the CAIR by subjecting EGUs to the EPA administered cap and trade program may consider BART satisfied for NO_X and SO_2 from BART-eligible EGUs. In the CAIR SNPR and supporting documentation,[72] we provided analyses demonstrating that CAIR would achieve greater emission reductions than BART, and would make greater reasonable progress according to the two-pronged visibility test previously proposed in the BART guidelines.

In February 2005, in *CEED* v. *EPA*, the D.C. Circuit invalidated a BART-alternative program developed by the Western Regional Air Partnership (WRAP), which was also based on a requirement of group-BART analysis in setting source-by-source benchmark. It is important to note that the two-pronged better-than-BART test was not

[69] See *Technical Support Document for BART NO_X Limits for Electric Generating Units and Technical Support Document for BART NO_X Limits for Electric Generating Units Excel Spreadsheet,* Memorandum to Docket OAR 2002–0076, April 15, 2005.

[70] *Id.*

[71] Section 308(e)(2) was based, in turn, on the precedent set by our interpretation of CAA 169A(b)(2) in a single BART-source context—see 64 FR 35739, citing *Central Arizona Water Conservation District,* 990 F.2d 1531 (1993).

[72] "Supplemental Air Quality Modeling Technical Support Document (TSD) for the Clean Air Interstate Rule (CAIR), May, 2004." *http://www.epa.gov/cair/pdfs/saqmtsd.pdf.*

at issue in CEED, as neither the States nor EPA had employed that test in determining that the WRAP's program achieved greater progress than BART. The issue on which the court based its decision was not how the two programs were compared, but how States were required to estimate reductions from source-by-source BART in order to make the comparison. The implications of this case to today's action are discussed in more detail below.

Finally, on March 10, 2005 we promulgated the final CAIR. In the final CAIR, we presented refined and updated analyses continuing to show that CAIR makes greater progress than BART. We concluded at that time that we should defer a final "better than BART" determinations until (1) the source-by-source BART guidelines for EGU were promulgated, and (2) the criteria for comparing alternatives to BART were also finalized. We are taking both of those actions today, and, as explained below, are therefore also making our final determination that CAIR achieves greater progress than BART and may be used by States as a BART substitute.

Final Criteria for Comparing Visibility Progress of an Alternative Program to BART

Proposed Rule. As noted, the criteria for determining if an alternative measure achieves greater reasonable progress than BART (also known as the "better than BART" test or the two-pronged visibility test) were first proposed in the 2001 BART guideline proposal and reproposed in the identical form in the 2004 BART guidelines reproposal. The test appeared as an element of the guideline's overview of the steps involved in developing a trading program consistent with regional haze rule section 308(e)(2).

Specifically, the guidelines provided that States could first look at the geographic distribution of emissions under the trading program. "If [the] distribution of emissions is not substantially different than under BART, and greater emissions reductions are achieved, then the trading program would presumptively achieve "greater reasonable progress." (69 FR at 25231). If the distribution of emissions is expected to be different, then States are directed to conduct an air quality modeling study. The guidelines then provide that

"[t]he modeling study would demonstrate "greater reasonable progress" if both of the following two criteria are met:

—Visibility does not decline in any Class I area, and

—Overall improvement in visibility, determined by comparing the average differences over all affected Class I areas

Comments Received

Several commenters stated that the trading criteria contained in the proposed BART guidelines were, along with other parts of the guidelines, beyond EPA's authority to impose under the CAA.

Several State commenters asked for clarification of what should be considered a significantly different geographic distribution of emission reductions, for purposes of proceeding to the two-pronged visibility test.

One comment, submitted by environmental groups in response to our preliminary application of the two-pronged test to the CAIR in the CAIR rulemaking, goes to the permissibility of that test in general and is therefore relevant to the finalization of the test. Specifically, these commenters stated 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 uses averaging of visibility improvement across different Class I areas.

Final Action. We are amending the regional haze rule to incorporate the two- prong visibility test as it was previously proposed in the BART guideline proposals. Specifically, we are adding the test to the rule provisions at section 51.308(e)(3).

The EPA has the authority to prescribe this methodology under its general rulemaking authority provided by CAA section 301(a), and under CAA sections 169A(4) and 169(e). The latter provisions require EPA to promulgate regulations to assure reasonable progress towards the national visibility goal and to assure compliance with the requirements of section 169A, which include the requirements for BART under section 169A(b)(2)(A), and to promulgate such measures as may be necessary to carry out these regulations. The EPA has determined that source-by-source BART need not be required when it is not necessary to meet reasonable progress because greater progress can be achieved by an alternative means. The D.C. Circuit in CEED upheld this interpretation of the BART provisions' relationship to the broader reasonable progress requirements of the Act. 398 F.3d at 660. In order to assure that such alternative programs meet the reasonable progress goals of the CAA, EPA has the authority, and perhaps a duty, to promulgate regulations governing how that determination is made.

Moreover, these requirements for making the ultimate comparison between an alternative program and BART do not affect in any way how states make BART determinations or how they determine which sources are subject to BART. It is in those areas where the Act and legislative history indicate that Congress evinced a special concern with insuring that States would be the decision makers. Nothing in American Corn Growers or CEED suggests that those cases rendered EPA's rulemaking authority under section 169A(a)(4) completely inoperable in any BART context.

With respect to the use of average overall improvement, we explained in the CAIR NFR preamble that we disagree with comments that CAA section 169A(b)(2)'s requirement of BART for sources reasonably anticipated to contribute to impairment at any Class I area 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, CAA section 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. See 40 CFR 51.302. In addition, within a regional haze context, not every measure taken is required to achieve a visibility improvement at every class I area. BART is one component of long term strategies to make reasonable progress, but it is not the only component. The requirement that the alternative achieves greater progress based on the average improvement at all Class I areas assures that, by definition, the alternative will achieve greater progress overall. Though there may be cases where BART could produce greater improvement at one or more class I areas, the no-degradation prong assures that the alternative will not result in worsened conditions anywhere than would otherwise exist, and the possibility of BART for reasonably attributable visibility protects against any potential "hot spots." Taken together, the EPA believes these factors make a compelling case that the proposed test properly defines "greater reasonable progress." The EPA anticipates that regional haze implementation plans will also contain measures addressing other sources as necessary to make progress at every mandatory Federal Class I area.

We are therefore finalizing the test criteria in the same form in which they were proposed as part of the BART guidelines. We also recognize that the test criteria leave some terms and conditions undefined, and we believe States and Tribes should retain the discretion to reasonably interpret and apply these terms as appropriate to the context of the particular program at issue.

First, in the proposed test we did not specify the time period which should serve as the starting point for comparison under the first prong. That is, we did not specify whether potential degradation should be determined in relation to visibility conditions existing at the time of the proposed program, or in relation to base case visibility projections for the time of program implementation. While either option is, we believe, reasonable, in this rulemaking we have used the future projected base case, for the following reasons.

The underlying purpose of both prongs of the test is to assess whether visibility conditions at Class I areas would be better with the alternative program in place than they would without it. The first prong ensures that the program does not cause a decline in visibility at any particular Class I area. It addresses the possibility that the alternative program might allow local increases in emissions which could result in localized degradation. The second prong assesses whether the alternative program produces greater visibility improvement in the aggregate than would source specific BART.

In both cases, the logical reference point is visibility conditions as they are expected to be at the time of program implementation but in the absence of the program. This insures that the visibility improvements or degradations determined are due to the programs being compared—source-specific BART and the cap-and-trade alternative—and not to other extrinsic factors. For example, if large increases in wild land fires are expected, due to accumulation of fuel from past forest management practices, a degradation of visibility from current conditions may be expected. It would be irrational to disapprove an alternative program because of a modeled degradation from current conditions, where that degradation is actually anticipated because of smoke from such fires—sources which are not subject to the CAA BART provisions. By comparing the alternative to future projected baseline conditions, such extrinsic variables are accounted for. We are thus able to ascertain (to the extent possible where future projections are concerned) whether visibility under the alternative would decline at any Class I area, all other things being equal.

Therefore, in applying the test to the CAIR, we used the future (2015) projected baseline. We believe, however, that States should have discretion in determining the most appropriate baseline for this prong of the test, as long as the State's method is reasonable.

Second, although the proposed test indicated that dispersion modeling should be used to determine visibility differences for the worst and best 20 percent of days, the guideline did not specify the relationship between the worst and best days and the two prongs of the test. We believe that each prong of the test should ideally be based on an examination of both the worst and best 20 percent of days. Thus, under the first prong, visibility must not decline at any one Class I area on either the best 20 percent or the worst 20 percent days [73] as a result of implementing the alternative program; and, under the second prong both the best and worst days should be considered in determining whether the alternative program produces greater average improvement.

Third, the proposed guidelines did not define "affected" Class I areas for purposes of the comparison. In applying the test to the CAIR, we considered all federal mandatory Class I areas in the contiguous 48 States for which data was available. The principal Class I areas affected by the CAIR are those in the eastern U.S., therefore we calculated average improvement separately for the eastern areas, but also considered affects at all Class I areas nationally. We believe this was appropriate for a federally mandated program of the scope and magnitude of the CAIR. However, this may not be necessary for every BART-alternative program developed by States in the future, especially if proposed programs are limited to smaller geographic areas or are limited to source categories having significantly less widespread impacts than EGUs. In such circumstances, it may be reasonable for the States and Tribes involved to develop criteria for "affected" Class I areas. For example, the affected region could be considered to be the States and Tribes involved in the trading program as well as immediately adjacent States, or Class I areas within adjacent States that are within some defined distance of participating States.

With respect to comments on the degree of difference in the geographic distribution of emissions necessary to trigger application of the two prong test, we believe it is not necessary for EPA to define that in the rule. For our CAIR analysis, we explained in the SNPR that the fact that CAIR would produce greater emissions reductions than BART in most States, but less reductions than BART in a few States, was sufficient reason to employ the two pronged visibility test, 69 FR 32704. For other programs developed by States, a State would have the ability to make a reasonable decision as to whether there was a sufficient basis to make the demonstration that an alternative program would be better than BART based on modeling of the emissions distributions alone, or whether the State should proceed with the two-pronged visibility test. The State's discretion is subject as always to the condition that it must be reasonably exercised, and must be supported by adequate documentation of the analyses.

Finally, on a related issue, we note that in a separate rule making to follow soon after today's action, we will be soliciting comments on whether there might be other means of demonstrating that an alternative program makes greater reasonable progress than BART, in addition to the two-pronged visibility test we are finalizing in today's action. Such other means might take into account additional policy considerations, as well as the relative degree of visibility improvement of the two programs.

C. Final Determination That CAIR Makes Greater Reasonable Progress Than BART

Proposal. As noted in the background section above, in both the CAIR SNPR, and NFR, we discussed the proposed approach of allowing States to treat CAIR as an in-lieu-of BART program for EGUs in CAIR-affected States. In both actions, we presented analyses based on emission projections and air quality modeling showing that CAIR will achieve greater reasonable progress

[73] The regional haze rule requires States to establish reasonable progress goals for each Class I area that provide for improvement in visibility for the most impaired days and ensure no degradation in visibility for the most impaired days. The reasonable progress test in the regional haze rule remains as a separate test from better than BART. The SIPs must contain measures to achieve the reasonable progress goal; such measures could include not only stationary source programs such as BART but also programs to address emissions from other types of sources. The no degradation (on the 20 percent best days) component of the reasonable progress test must still be applied to the final future year emissions control strategy. This does not directly impact the conclusions of the better than BART test.

towards the national visibility goal than would BART for affected EGUs. These analyses were conducted according to the criteria for making such "better than BART" determinations which had been proposed in the BART guidelines, and which have now been finalized in the regional haze rule at 40 CFR 51.308(e)(3), as discussed above in section IV.B. Below, we briefly recap these prior analyses. See 69 FR 32684, 32702–32707 and 70 FR 25162, 25299–25304 and associated Technical Support Documents[74] for full details.

Scenarios Examined

The CAIR is applicable to 28 States and the District of Columbia and requires levels of SO_2 and NO_X emissions reductions based on those achievable on a highly cost effective basis from EGUs. BART, on the other hand, is applicable nationwide and covers 25 additional industrial categories, as well as EGUs, of a certain vintage. In our comparison, we sought to determine whether the CAIR cap and trade program for EGUs will achieve greater reasonable progress than would BART for EGUs only. Therefore, the relevant scenarios to examine were (1) SO_2 and NO_X emissions from all EGUs nationwide after the application of BART controls to all BART-eligible EGUs ("nationwide BART"), and (2) SO_2 and NO_X emissions from all EGUs nationwide after the emissions reductions attributable to CAIR in the CAIR region and application of BART controls to all BART-eligible EGUS outside the CAIR region ("CAIR + BART"). The latter scenario reflects the fact that source-by-source BART would remain a federal requirement outside the CAIR region, unless and until it is replaced by some other state or federally required program. Thus, in order to more accurately project CAIR emissions, it is necessary to impose BART controls outside the CAIR region, to account for potential load and emission shifting among EGUs.

In addition to these two scenarios, a third was used—the future base case in the absence of either program. This third scenario was used to ensure that CAIR would not cause degradation from otherwise existing conditions. See section IV.B above for a discussion of why the future baseline is an appropriate comparison point for the first prong of the "better than BART" test.

At the SNPR stage, a "CAIR + BART" scenario was not available, as the only projections available at that time had been developed for other purposes. Thus, the "CAIR" scenario used then, which was based on the Clear Skies proposal, 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.

For the CAIR NFR, we redid the emissions projections for both the Nationwide BART and CAIR + BART in the West scenarios. For the former, we increased the number of BART-eligible units included by lowering the assumed threshold for BART applicability from 250 MW capacity for both NO_X and SO_2 to 100 MW for SO_2 and 25 MW for NO_X, and by reviewing the list of potentially BART-eligible EGUs. For the latter scenario, we produced emissions projections based on application of CAIR-level emission reductions in the States proposed for inclusion in the CAIR in the SNPR.

Emission Projections. For the analyses in both the SNPR and NFR, we used the Integrated Planning Model (IPM) to estimate emissions expected from the scenarios described above. Tables 1 and 2 present the results from the SNPR and NFR, respectively.

TABLE 1.—EGU SO_2 AND NO_X EMISSIONS—AS PROJECTED IN CAIR SNPR

[In thousands of tons per year]

	2015 Base case EGU emissions	2015 "CAIR"	2015 Modeled nationwide e Bart	Additional reduction from "CAIR" (nationwide BART minus "CAIR")
Nationwide SO_2	9,081	5,260	7,012	1,752
Nationwide NO_X	3,950	2,248	2,781	533

TABLE 2.—EGU SO_2 AND NO_X EMISSIONS—AS PROJECTED IN CAIR NFR

[In thousands of tons per year]

	2015 Base case EGU emissions	2015 CAIR + BART	2015 Nationwide BART	Additional reduction from CAIR + BART (nationwide BART minus CAIR+BART)
Nationwide SO_2	9,084	4,735	7,162	2,427
Nationwide NO_X	3,721	1,816	2,454	638

As can be seen in the numbers in the right-most column, CAIR produced far superior emission reductions to nationwide BART, and the superiority of CAIR over BART increased between the SNPR and NFR projections, when the scenarios were corrected to more accurately reflect the anticipated reality in 2015.

Air Quality Modeling Results. The proposed "better-than-BART" test provided that if the distribution of emission reductions is substantially the same under the alternative program as under BART, then the demonstration can be made simply by comparing emission reductions. If, however, the distribution is significantly different,

[74] *Supplemental Air Quality Modeling Technical Support Document (TSD) for the Clean Air Interstate Rule (CAIR),* May, 2004. *http://www.epa.gov/cair/pdfs/saqmtsd.pdf;* Demonstration that CAIR Satisfies the 'Better-than-BART' Test as proposed in the Guidelines for Making BART Determinations, EPA Docket Number OAR–2003–0054–YYYY, March 2005. *http://www.epa.gov/cair/pdfs/finaltech04.pdf.*

then visibility modeling is required in order to apply the two pronged test previously described. As noted above, CAIR emission reductions were vastly greater than those under BART. However, because there were some differences in the geographic distribution of reductions on a state-by-state basis, in order to be conservative we conducted air quality modeling and evaluated CAIR under the two pronged test.

Specifically, using the above emissions projections, we completed numerous air quality modeling runs and postprocessing calculations to determine the impacts of emissions and emissions control strategies on visibility in Class I areas. We quantified the impacts of the CAIR and BART controls on visibility impairment by comparing the results of the future-year (2015) base case model runs with the results of the CAIR + BART and nationwide BART control strategy model runs. We quantified visibility impacts on the 20 percent best and 20 percent worst visibility days.

For the SNPR modeling, we used the Regional Modeling System for Aerosols and Deposition (REMSAD) model to calculate these visibility impacts. This modeling used base year meteorology from 1996. Complete year ambient monitoring data, which is necessary to model future improvements in visibility, was available for 1996 from Inter-agency Monitoring of Protected Visual Environments (IMPROVE) monitors located at 44 Class I areas—13 within the CAIR region and 31 outside of it.

For the NFR modeling, we used the Community Multiscale Air Quality (CMAQ) model. The base year meteorology used in the CMAQ modeling was 2001. This later base year enabled us to look at more Class I areas, because there were more IMPROVE monitors which had complete year data for 2001 than there had been in 1996. Specifically, 81 of the 110 IMPROVE sites have complete ambient air quality data for 2001. Moreover, because in some cases a given IMPROVE monitor is designated as representing more than one Class I area, these 81 sites are representative of 116 Class I areas. Twenty nine of the 116 are in the East (east of 100 degrees longitude) and 87 are in the West.

Using the modeling results, we then applied the two prong better than BART test which had been defined in the proposed BART rule. As explained above, under the first prong, visibility must not decline at any Class I area, as determined by comparing the predicted visibility impacts at each affected Class I area under the (CAIR) trading program with future base case visibility conditions. Under the second prong, overall visibility, as measured by the average improvement at all affected Class I areas, must be better under the trading program than under source-specific BART. The future year air quality modeling results were used to make this demonstration.

The visibility impacts of the CAIR + BART scenario were compared to base case 2015 visibility conditions (without CAIR or BART) to determine whether the CAIR resulted in a degradation of visibility at any Class I area. We also compared these visibility impacts with the visibility impacts of nationwide BART implementation, to assess whether the proposed CAIR would result in greater average visibility improvement than nationwide BART.

The CAIR passed the first prong by not causing a degradation of visibility at any Class I area, either in the West or nationally. This was true in both the SNPR and NFR modeling. The visibility projections for each Class I area are presented in the respective TSD's.[75]

The overall results are presented in tables 3 and 4 below, representing the SNPR and NFR modeling respectively.

TABLE 3.—AVERAGE VISIBILITY IMPROVEMENT IN 2015 VS. 2015 BASE CASE (DECIVIEWS) AS MODELED USING REMSAD IN CAIR SNPR

Class I areas	"CAIR" Scenario		Nationwide BART	
	East[76]	National	East	National
20 percent Worst Days	2.0	0.7	1.0	0.4
20 percent Best Days	0.7	0.2	0.4	0.1

TABLE 4.—AVERAGE VISIBILITY IMPROVEMENT IN 2015 VS. 2015 BASE CASE (DECIVIEWS) AS MODELED USING CMAQ IN CAIR NFR

Class I Areas	CAIR + BART in West		Nationwide BART	
	East[76]	National	East	National
20 percent Worst Days	1.6	0.5	0.7	0.2
20 percent Best Days	0.4	0.1	0.2	0.1

As can be see from the tables, although the models produced different absolute values, in both cases CAIR produced significantly greater visibility improvement than nationwide BART. For example, looking at the 20 percent worst days at Eastern Class I areas (the areas most influenced by the CAIR, since it is an eastern program), in both cases the visibility improvements from CAIR were at least twice as great as under nationwide BART (*i.e.*, in the SNPR, 2.0 deciviews compared to 1.0 deciviews improvement, and in the NFR, 1.6 deciviews compared to 0.7 deciviews improvement).

This historical overview is given in the interest of providing a more complete understanding of the analyses presented at various stages in the CAIR rule making progress. In the end, however, it is the analyses presented in the CAIR NFR on which we are basing our determination that CAIR makes greater reasonable progress towards the national visibility goals than does nationwide BART. Therefore, these NFR results are examined more closely in the "Final Action" section below, in light of additional emissions projections we

[75] See Footnote [74], Supra.

[76] 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

have conducted to insure that changes to the CAIR and BART rules made subsequent to the CAIR NFR do not affect that determination.

Comments Received and EPA's Responses

Although many comments were received regarding our proposal to determine that CAIR makes greater reasonable progress than BART, nearly all of them related either to the terms of the test itself, or to policy and legal implications of allowing CAIR required reductions to substitute for source-by-source BART. These are addressed in sections B (above) and D (below) respectively. One commenter asserted, with respect to modeling presented in the SNPR, that the improvement of CAIR compared to source-specific BART is so slight it may be potentially within the margin of error, and therefore insufficient for the better than BART demonstration, or for assuring that no hot spots will occur.

The EPA disagrees that the difference between CAIR and BART in the SNPR visibility projections was not significant. The visibility results presented in the NFR continue to show that the CAIR cap and trade program with BART in the non-CAIR region provides considerably more visibility improvement compared to nationwide BART (for EGUs only). The NFR modeling results show that the average visibility improvement from CAIR on the 20 percent worst days at 29 Eastern Class I areas is 1.6 deciviews (dv) compared to only a 0.7 dv improvement from nationwide BART controls. In the "better than BART" TSD we have provided modeling results for 116 individual Class I areas. The modeling shows that CAIR will not create any "hot spots." On the 20 percent worst days, all of the Eastern Class I areas show more visibility improvement under CAIR+BART than under BART alone. In many of the Western Class I areas, nationwide BART and CAIR + BART in the West provide about the same visibility benefits. (This is to be expected, since the CAIR is only applicable in the East.) While the visibility benefits are similar in the West (outside of the CAIR region), they are clearly not similar in the East, where the CAIR is predicted to achieve twice as much visibility improvement compared to BART.

Final action. The CAIR vs. BART comparison presented in the CAIR NFR was developed while both rules were under development and therefore subject to change. Since the emissions projections and air quality modeling presented in the CAIR NFR was completed, several changes were, in fact, made to the CAIR region. In addition, since that time our assumptions regarding the likely maximum BART emission reductions from EGUs also changed. Therefore, we recalculated the emission projections to see if the rule changes could possibly affect the determination that CAIR will achieve greater reasonable progress than BART.

Most significantly, the final CAIR included Arkansas, Delaware, and New Jersey only for purposes of significant contribution to ozone non-attainment by summertime NO_X emissions, whereas our modeling had been based on the assumption that these States would be included for contribution to $PM_{2.5}$ non-attainment by SO_2 and NO_X emissions. The new emission projections are based on the application of CAIR only for ozone in these States.

With respect to the nationwide BART, for SO_2 the NFR projections assumed the application of a 90 percent control or 0.10 lbs/mmBtu at uncontrolled EGUs greater than 100 MW. In the new projections, the control assumptions were changed to 95 percent or 0.15 lbs/mmbtu, to reflect the presumptive control levels in the final BART guidelines. For NO_X, the NFR projections were based on an assumed emission rate of 0.2 lbs/mmBTU at all BART eligible EGUs nationwide. The new projections are based on the assumption of combustion controls on all BART eligible units except cyclones which have SCR, and the operation of all existing SCR and SNCRs annually, instead of just in the ozone season. Finally for both pollutants, the threshold for application of controls was increased to 200 MW, to better reflect the presumptions included in the final BART guidelines.

We used IPM to project 2015 emissions given these new parameters. The results are presented in Table 5 below, which also includes the CAIR NFR projections (as reported in Table 2) for the reader's convenience.

TABLE 5.—EGU SO_2 AND NO_X EMISSIONS—AS PROJECTED IN CAIR NFR AND AS PROJECTED IN SUBSEQUENT UPDATE

(In thousands of tons per year)

	2015 CAIR + BART	2015 Nationwide BART	Additional reduction from CAIR + BART (nationwide BART minus CAIR+BART)
CAIR NFR:			
Nationwide SO_2	4,735	7,162	2,427
Nationwide NO_X	1,816	2,454	638
Updated Projections:			
Nationwide SO_2	5,042	7,953	2,911
Nationwide NO_X	2,000	2,738	738

The updated emissions estimates for both the BART and CAIR with BART in the West scenarios are slightly higher than the NFR emissions estimates, but the difference between the CAIR + BART and nationwide BART scenarios are even larger compared to the NFR determination. For SO_2, the updated CAIR + BART achieves about 2.9 million tons more reductions than updated nationwide BART in 2015. For NO_X, the updated CAIR + BART policy is projected to result in about 738,000 tons more emissions reductions than the updated BART nationwide policy in 2015. The difference between the updated CAIR + BART and nationwide BART scenarios is now larger by 484,000 tons of SO_2 reduction (*i.e.*, 2,911,000 − 2,427,000) and 100,000 tons of NO_X reduction (*i.e.* 738,000 − 638,000).

Implications of New Emission Projections for the Two-Pronged Test

The first prong of the better than BART test specifies that no degradation of visibility can occur at any Class I area. In order to be sure that Class I areas do not experience a degradation in visibility, we examined the updated State by State emissions estimates. Compared to the 2015 base case, in the updated CAIR + BART case, there are no individual Statewide increases in either SO_2 or NO_X (except for a very small ~1,000 ton increase in NO_X in Connecticut and 2,000 ton increase in SO_2 in New Jersey).[77] That is consistent with the NFR CAIR + BART case in which no degradation was found. Consequently we have determined that no degradation would occur under the updated CAIR + BART emissions scenario.

The second prong of the better than BART test specifies a greater average visibility improvement from the CAIR trading program (CAIR + BART). The average visibility improvement from the NFR CAIR + BART case was much greater (on the 20 percent worst visibility days) than the nationwide BART case. In the scenario we modeled for the NFR, the larger visibility improvement from CAIR + BART was achieved by reducing SO_2 emissions by an additional ~2.4 million tons per year compared to nationwide BART and NO_X emissions by an additional 638,000 tons per year compared to natiowide BART.

In the updated scenario, the emissions difference between the CAIR + BART and nationwide BART cases are even larger (2.9 million tons of SO_2 and 738,000 tons of NO_X).[78] The distribution of emission reductions changed somewhat in the new projections—that is, some States saw a larger difference between CAIR and BART, while in other States the difference was smaller. The largest change was in Kentucky, where the new projections showed that emission reductions from CAIR were even greater than those from BART by an additional 200,000 tons per year. Among States where the change between projections went the other direction—that is, showing that BART reductions were closer to CAIR reductions than previously projected—the greatest changes were in Alabama and Pennsylvania, where the difference between the programs decreased by 46,000 and 45,000 tons, respectively.

Perhaps more importantly, in the new projections, there are fewer States in which BART reductions are greater than CAIR reductions. In the NFR projections, there were 12 States[79] where nationwide BART SO_2 reductions were greater than CAIR + BART reductions.[80] In those 12 States, BART emissions achieved approx. 686,000 more tons of SO_2 reduction compared to CAIR + BART. In the rest of the States, CAIR + BART achieved an additional 3.1 million tons per year of SO_2 reduction compared to BART. All told, the modeling showed that visibility improvement was greater under the CAIR than under BART on an overall average basis, both at eastern Class I areas and at all Class I areas nationally. In the new projections, CAIR + BART achieved an additional 3.4 million tons per year of SO_2 reduction compared to BART in 39 of the 48 States. In the remaining 9 States[81] BART achieved approx. 472,000 more tons of SO_2 reduction compared to CAIR + BART in the west.[82]

Due to the fact that the new projections show that the difference between CAIR and BART reductions is even greater than previously estimated, and the visibility improvements due to CAIR + BART were previously modeled to be much larger than BART, we can state with a high degree of confidence that the updated CAIR + BART scenario passes the second prong of the better than BART test.

D. Revision to Regional Haze Rule To Allow CAIR States To Treat CAIR as a BART-Substitute for EGUs

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 at affected EGUs. To implement this, we proposed an amendment to the Regional Haze Rule which would add a subpart 40 CFR 51.308(e)to read as follows:

> 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.[83]

We proposed that this would be codified at 40 CFR 51.308(e)(3); however, that section now incorporates the "better than BART" test as discussed above. In today's action, as described below we are finalizing this provision of the rule, where it will be codified as section 308(e)(4).

The EPA's authority to treat emissions reductions required by the CAIR as satisfying BART was not affected by *CEED.* As noted, the D.C. Circuit in *CEED* upheld the proposition that EPA can approve implementation plans which rely on alternative strategies to BART, as long as greater reasonable progress is achieved. *CEED,* 398 F.3d at 660. Moreover, the CAIR program is not infected in any way with the "group BART" methodology held invalid by the court. That is because CAIR emission reductions levels were not based on the invalid "group-BART" approach or any other assumptions regarding BART, but were developed for other reasons. Specifically, the CAIR was developed to assist with attainment of the NAAQS for $PM_{2.5}$ and ozone. Had EPA not performed the comparison of CAIR to BART for visibility progress purposes, the CAIR emission reduction requirements would remain unchanged. Therefore, EPA is not imposing an invalid BART requirement on States, but rather allowing States, at their option, to utilize the CAIR cap and trade program as a means to satisfy BART for affected EGUs.

We received numerous comments on this proposal, which are summarized along with our responses in the CAIR NFR preamble at 70 FR 25300–25302 and in the Response to Comment document. To summarize our responses to some of the most important comments:

[77] The 1,000 ton per year increase in NO_X in Connecticut represents approx. 0.003 percent of the total EGU NO_X in the 2015 base case and the 2,000 ton per year increase in SO_2 in New Jersey represents approx. 0.0005 percent of the total EGU SO_2 . Since the impacts on visibility from EGU SO_2 and NO_X are generally regional in nature, we would expect this small increase to have little or no impact on visibility in any Class I area.

[78] The difference between the updated CAIR + BART and nationwide BART scenarios is larger than the difference between the modeled CAIR + BART and nationwide BART scenarios. The "difference of the differences" is 485,000 tons of SO_2 and 100,000 tons of NO_X.

[79] California, Delaware, Florida, Georgia, Iowa, Louisiana, Michigan, Mississippi, Missouri, North Carolina, Texas, and Wisconsin.

[80] There were also four States where BART NO_X emissions reductions were slightly higher than CAIR + BART (a total of 4,000 tons per year). Those States are Connecticut, Delaware, New Jersey, and Oklahoma.

[81] Alabama, Louisiana, Michigan, Mississippi, Missouri, New Jersey, North Carolina, Texas, Wisconsin.

[82] We performed a similar analysis using projections including the Clean Air Mercury Rule, CAMR, which was promulgated after the CAIR NFR. The CAMR emission projections show slight additional emission reductions of SO_2 and NO_X as compared to the projections CAIR + BART without CAMR, and are nearly identical in terms of geographic distribution. Therefore CAIR + BART + CAMR, like CAIR + BART, passes the two-pronged test for demonstrating greater reasonable progress than BART. This is discussed in more detail in the TSD accompanying today's action.

[83] A geographic enhancement is a method, procedure, or process to allow a broad regional strategy, such as the CAIR cap & trade program, to accommodate BART for reasonably attributable impairment. For example, it could consist of a methodology for adjusting allowance allocations at a source which is required to install BART controls.

(1) We note that we are not constraining the discretion of States to determine which sources are subject to BART and to make BART determinations. CAIR-affected States are not required to accept our determination that CAIR may substitute for BART. Under the amended rule, States simply have the option of accepting this determination.

(2) The EPA does not believe that anything in the CAA or relevant case law prohibits a State from considering emissions reductions required to meet other CAA requirements when determining whether source by source BART controls are necessary to make reasonable progress. Whatever the origin of the emission reduction requirement, the relevant question for BART purposes is whether the alternative program makes greater reasonable progress. As discussed above, EPA has determined that CAIR does so with respect to SO_2 and NO_X from EGUs in the CAIR region.

Moreover, the fact that BART and CAIR originate from different provisions of the CAA does not mean that CAIR and BART emissions reductions would be additive if BART-eligible EGUs in the CAIR program were required to install and operate BART. Such source specific control requirements would simply result in a redistribution of emission reductions, as other EGUs could buy the excess allowances generated by the installation of controls at BART units. The net result would be the same level of emission reductions, but at a higher total cost, because the ability of the market to find the most cost effective emission reductions would be constrained.

(3) Although regional haze rule section 308(e)(2) is not directly applicable, as the CAIR is covered by the special provision newly codified at section 308(e)(4), this determination is consistent with the policy contained in section 308(e)(2) requiring in-lieu of BART programs be based on emissions reductions "surplus to reductions resulting from measures adopted to meet requirements as of the baseline date of the SIP." The baseline date for regional haze SIPs is 2002;[84] therefore CAIR reductions are surplus to requirements as of that year.

(4) We agree with commenters that it was premature to make a final determination whether CAIR makes greater reasonable progress than BART in the final CAIR because at that time the BART guidelines and the criteria for making such determinations had not been finalized. In today's action, both those rule makings are complete and therefore such a determination is ripe.

(5) We disagree with commenters who thought that CAIR should be considered "better than BART" regardless of whether a State participates in the cap and trade program. Our demonstration that CAIR makes greater reasonable progress than BART is based only on an examination of emissions reductions from EGUs under both programs. The CAIR emissions projections and modeling assumes that EGU emissions will be capped at the levels specified in the CAIR. Therefore, States that choose to meet their CAIR emission reduction requirements in a manner other than through the participation of EGUs in the CAIR cap and trade program would have to develop an appropriate demonstration that the measures they employ make greater reasonable progress than would BART for any affected source categories, if the State wanted its CAIR-required reductions to substitute for source-by-source BART.

(6) We disagree with commenters who asserted that CAIR should satisfy BART for States that are subject to CAIR only for ozone season NO_X. We explained in the final CAIR preamble that a State subject to 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. We wish to clarify here that a State which is only subject to CAIR for NO_X, but which also chooses to participate in the CAIR trading program for both SO_2 and NO_X, may consider BART to be satisfied for both SO_2 and NO_X from EGUs. Because we modeled these States as controlling for both SO_2 and NO_X in the CAIR NFR, our better than BART demonstration presented in that action would be valid in that scenario. Conversely, if such States choose to participate only in the ozone season NO_X trading program, the updated projections presented in today's action demonstrate that BART would be satisfied for NO_X, but such states would still need to address BART for SO_2 emissions from EGUs.

(7) We noted in the final CAIR preamble that although we believe it is unlikely that a State or FLM will find it necessary to certify reasonably attributable visibility impairment at any Class I area, as a legal matter that possibility exists. That is, the determination that CAIR makes greater reasonable progress than BART is made in the context of BART for regional haze under CAA 169B, and does not preclude a finding of reasonably attributable impairment under CAA 169A. The CAIR cap and trade program does not include geographic enhancements to accommodate the situation where BART is required based on reasonable attribution at a source which participates in the trading program, but States retain the discretion to include such enhancements in their SIPs.

(8) Our determination that CAIR makes greater reasonable progress than BART for EGUs is not a determination that CAIR satisfies all reasonable progress requirements in CAIR affected States. Each State, whether in the CAIR region or not, is required to set reasonable progress goals for each Class I area within the State as required in regional haze rule section 308(d)(1), and to develop long term strategies, considering all anthropogenic sources of visibility impairing pollutants, as required by section 308(d)(3).

In setting the reasonable progress goals, the State is to consider the amount of visibility improvement needed to achieve a uniform rate of progress towards natural background conditions in the year 2064. (This uniform rate of progress is sometimes referred to as the default glide-path). The State is also to consider the statutory reasonable progress factors contained in CAA section 169A(g)(1).[85]

In doing so, we anticipate that States will take into account the degree to which CAIR emissions reductions are projected to bring visibility conditions at its Class I areas in line with the default glide path. In some States, the improvements expected from CAIR, combined with the application of the reasonable progress factors to other source sectors, may result in a determination that few additional emissions reductions are reasonable for the first long term strategy period. Nonetheless, each State is required to set its reasonable progress goals as provided by the regional haze rule and cannot assume that CAIR will satisfy all of its visibility-related obligations.

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), EPA must determine whether the regulatory action is "significant" and, therefore, subject to Office of Management and Budget

[84] See Memorandum from Lydia Wegman and Peter Tsirigotis, *2002 Base Year Emission Inventory SIP Planning: 8-hr Ozone, $PM_{2.5}$, and Regional Haze Programs*, November 8, 2002. *http://www.epa.gov/ttn/oarpg/t1/memoranda/2002bye_gm.pdf.*

[85] Similar to the BART factors, the reasonable progress factors are: the cost of compliance, the time necessary for compliance, the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any existing sources subject to such requirements.

(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 impacts 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.

Pursuant to the terms of Executive Order 12866, it has been determined that this rule is a "significant regulatory action," thus EPA has submitted this rule to OMB for review. The drafts of the rules submitted to OMB, the documents accompanying such drafts, written comments thereon, written responses by EPA, and identification of the changes made in response to OMB suggestions or recommendations are available for public inspection at EPA's Air and Radiation Docket and Information Center (Docket Number OAR–2002–0076). The EPA has prepared the document entitled "Regulatory Impact Analysis of the Final Clean Visibility Interstate Rule or Guidelines for Best Available Retrofit Technology Determinations Under the Regional Haze Regulations" (RIA) to address the requirements of this executive order.

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 three possible regulatory scenarios that States may follow to implement the BART rule and guidelines. The economic analyses also address issues involving requirements of the Paperwork Reduction Act (PRA), potential small business impacts, unfunded mandates (including impacts for Tribal governments), environmental justice, children's health, energy impacts, and other statutory and executive order requirements.

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 beneficial to society, with annual net benefits (benefits less costs) ranging from approximately $1.9 to $12.0 billion in 2015. These alternative net benefits estimates reflect differing assumptions about State actions taken to implement BART and about the social discount rate used to estimate the annual value of the benefits and costs of the rule. All amounts are reflected in 1999 dollars. The range of benefits and costs reported for the BART represent estimates of EPA's assessment of State actions that will likely be taken to comply with the BART rule and guidelines.

a. Control Scenarios

Today's rule sets forth presumptive requirements for States to require EGUs to reduce SO_2 and NO_X emissions for units greater than 200 megawatts (MW) in capacity at plants greater than 750 MW in capacity that significantly contribute to visibility impairment in Federal Class I areas (national parks). The analysis conducted in the RIA presents alternative control scenarios of possible additional controls for EGUs located at plants less than 750 MW in capacity. The EPA also calculated the amount of SO_2 and NO_X emissions reductions for several illustrative scenarios that reflect alternative State actions regulating industries with non-EGU sources. The analyses conducted include three regulatory alternative scenarios that States may choose to follow to comply with BART. The alternatives include three scenarios of increasing stringency—Scenario 1, Scenario 2, and Scenario 3. A brief discussion of the these alternatives for the EGUs and all other sources follows. More details of the alternative control scenarios and associated control costs are discussed in the RIA.

i. Electric Generating Units

In the revised BART guidelines, we have included presumptive control levels for SO_2 and NO_X emissions from coal-fired electric generating units greater than 200 megawatts (MW) in capacity at plants greater than 750 MW in capacity. Given the similarities of these units to other BART-eligible coal-fired units greater than 200 MW at plants 750 MW or less, EPA's guidance suggests that States control such units at similar levels for BART. The guidelines would require 750 MW power plants to meet specific control levels of either 95 percent control or controls of 0.15 lbs/MMBtu, for each EGU greater than 200 MW, unless the State determines that an alternative control level is justified based on a careful consideration of the statutory factors.[86] Thus, for example, if the source convincingly demonstrates unique circumstances affecting its ability to cost-effectively reduce its emissions, the State may take that into account in determining whether the presumptive levels of control are appropriate for the facility. For an EGU greater than 200 MW in size, but located at a power plant smaller than 750 MW in size, States may also find that such controls are cost-effective when taking into consideration the costs of compliance in the BART analysis in applying the five factor test for the BART determination. In our analysis we have assumed that no additional controls will occur where units have existing scrubbers and that no controls will occur for oil-fired units. While these levels may represent current control capabilities, we expect that scrubber technology will continue to improve and control costs will continue to decline.

For NO_X, for those large EGUs that have already installed selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) during the ozone season, States should require the same controls for BART. However, those controls should be required to operate year-round for BART. For sources currently using SCR or SNCR for part of the year, states should presume that the use of those same controls year-round is highly cost-effective. For other sources, the guidelines establish presumptive emission levels that vary depending largely upon boiler type and fuel burned. For coal-fired cyclone units with a size greater than 200 MW, our analysis assumes these units will install SCR. For all other coal-fired units, our analysis assumed these units will install current combustion control technology. In addition, we assume no additional controls for oil and/or gas-fired steam units.

We present alternative regulatory scenarios. Scenario 2 represents our application of the presumptive limits described above to all BART eligibility EGUs greater than 200 MW. For Scenario 1, we assume that only 200 MW BART-eligible EGUs located at facilities above 750 MW capacity will comply with the SO_2 requirements and NO_X controls. In this scenario, no

[86] These levels are commonly achievable by flue gas desulfurization controls ("scrubbers").

facilities less than 750 MW capacity are assumed to install BART controls. For Scenario 1, we assume that units with existing SCRs will operate those SCR units year round annually. In contrast in Scenario 3, we analyzed SO_2 controls equivalent to 95 percent reductions or 0.1 lbs per MMBtu on all previously uncontrolled units. NO_X controls for this most stringent scenario presume SCRs will be installed on all units greater than 100 MW capacity and combustion controls will be installed on units greater than 25 MW but less than 100 MW capacity. The EPA analyzed the costs of each BART scenario using the Integrated Planning Model (IPM). The EPA has used this model extensively in past rulemakings to analyze the impacts of regulations on the power sector.

The analysis presented assumes that BART-eligible EGUs affected by the Clean Air Interstate Rule (70 FR 25162) have met the requirements of this rule. Thus, no additional controls for EGUs beyond CAIR are anticipated or modeled for the 28 State plus District of Columbia CAIR region. In addition, we are assuming no additional SO_2 controls for sources located in States of Arizona, Utah, Oregon, Wyoming, and New Mexico or Tribal lands located in these States due to agreements made with the Western Regional Air Partnership (WRAP).

ii. Sources Other Than Electric Generating Units

As previously discussed there are 25 source categories potentially subject to BART in addition to EGUs (referred to as non-EGU source categories) as defined by the CAA. The EPA evaluated a set of SO_2 and NO_X emission control technologies available for these source categories and estimated the associated costs of control using AirControlNET. The control scenarios evaluated reflect control measure cost caps of up to \$1,000 per ton (Scenario 1), \$4,000 per ton (Scenario 2), and \$10,000 per ton (Scenario 3). The EPA also conducted a cost analysis for control costs of up to \$2,000 per ton and \$3,000 per ton, and the results of this analysis are presented in the RIA. The analysis consists of applying SO_2 and NO_X controls to each non-EGU source category up to the specified cost per ton "cap" in each scenario. These cost per ton caps are specified in average cost terms. As control stringency is increased, the marginal costs are also estimated for each non-EGU source category. The scenarios examined are based on the costs of technologies such as scrubbers for SO_2 control, and varying types of technologies for NO_X control. Scrubbers are the most common type of SO_2 control for most non-EGU sources for each scenario, while combustion controls such as low NO_X burners (LNB) and post-combustion controls such as selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR) are commonly applicable to most of the non-EGU source categories. Combustion controls are commonly applied as part of Scenario 1, while SNCR and SCR are more commonly applied either by themselves or in combination with combustion controls as part of Scenarios 2 and 3. Analyses are not available for 8 of the 25 non-EGU source categories, because there are no available control measures for these sources or there are no sources in these categories included in the non-EGU emissions data utilized in these analyses. All of these results are estimated using a nationwide database of BART-eligible non-EGU sources that is based on information collected from Regional Planning Organizations (RPOs) in the fall of 2004.

b. Baseline and Year of Analysis

The final rule sets forth the guidelines for States and Tribes for meeting the BART requirements under the CAA and the Regional Haze Rule. The Agency considered all promulgated CAA requirements and known State actions in the baseline used to develop the estimates of benefits and costs for this rule including the recently promulgated Clean Air Interstate Rule (70 FR 25162) and the proposal to include New Jersey and Delaware in the final CAIR region for fine particulate matter (70 FR 25408). However, EPA did not include within the baseline the actions States may take to implement the ozone and $PM_{2.5}$ NAAQS standards nor the recently promulgated Clean Air Mercury Rule. No additional SO_2 controls were assumed for any EGUs within the five WRAP States of Utah, Arizona, Wyoming, Oregon or New Mexico that have existing agreements to achieve reduction goals.

In the analysis, the controls and reductions are assumed to be required in 2015, a date that is generally consistent with the expected timing of the rule. States must submit SIPs relevant to the BART requirements in January 2008. After approval of the SIP, there is a 5 year compliance date. Thus, controls are likely to be installed and in operation by the end of 2013 or the beginning of 2014 to comply with the rule. In addition, EPA had existing inventories, modeling, and base case runs for 2015 to use for the analysis. The year 2015 is used in this analysis. All estimates presented in this report represent annualized estimates of the benefits and costs of BART in 2015 rather than the net present value of a stream of benefits and costs in these particular years of analysis.

c. Cost Analysis and Economic Impacts

For the affected region, the projected annual private incremental costs of BART to the power industry (EGU source category) range from \$253 to \$896 million in 2015 depending upon the scenario evaluated. These costs represent the private compliance cost to the electric generating industry of reducing NO_X and SO_2 emissions that EPA believes States may require to comply with BART.

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 for the EGU sector only are estimated to range from approximately \$119 to \$567 million in 2015 assuming a 3 percent discount rate. These EGU sector costs become \$141 to \$688 million in 2015 assuming a 7 percent discount rate.

Overall, the impacts of the BART are modest, particularly in light of the large benefits we expect. Retail electricity prices are projected to increase roughly 0.1 percent with BART in the 2015 timeframe under Scenario 2. Coal-fired generation, as well as coal production and natural gas-fired generation are projected to remain essentially unchanged as a result of this rule. It is also not expected that BART will change the composition of new generation built to meet growth in electricity demand. BART is also not expected to impact coal or natural gas prices.

For today's rule, EPA analyzed the costs for the EGU source category 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*.

The EPA also conducted an analysis of State actions in requiring emission controls for BART eligible sources in the non-EGU source categories. For the nation, the projected annual private incremental costs range from \$150 million to \$2.24 billion for industries with affected non-EGU sources. This cost range results from different assumptions about possible actions

States may take to comply with BART and alternative discount rates of 3 and 7 percent. The non-EGU private incremental control cost estimates are assumed to approximate the social costs of the rule for the non-EGU sector. The EPA analyzed the costs to non-EGUs sources using AirControlNET. The AirControlNET is a software tool that can be used to estimate the private costs and emission reductions of air pollution control policies for SO_2, NO_X, and other criteria pollutants throughout the contiguous U.S. for all manufacturing industries and many other industries. Documentation for AirControlNET can be found in the docket for this rulemaking or at *http://www.epa.gov/ttn/ecas/AirControlNET.htm.*

In summary, the EPA estimates that the annual social costs of this rule for the EGU and non-EGU source categories range from approximately $0.3 to $2.9 billion annually, based on alternative scenarios of State actions in response to the BART rule and guidelines assuming 3 or 7 percent discount rates. Estimates are reflected in 1999 dollars.

d. Human Health Benefit Analysis

Our analysis of the health and welfare benefits associated with this rule are presented in this section. Briefly, the analysis projects major benefits from implementation of the rule in 2015. As described below, thousands of deaths and other serious health effects would be prevented. We are able to monetize annual benefits ranging from approximately $2.2 to $14.3 billion in 2015. This range reflects different assumptions about States actions in response to the BART rule and the applicable discount rate (3 percent or 7 percent).

Table IV–1 presents the primary estimates of reduced incidence of PM- and visibility-related health effects for 2015 for the regulatory control strategy the EPA expects States may follow to comply with BART. In 2015 for Scenario 2, we estimate that PM-related annual benefits include approximately 1,600 fewer premature fatalities, 890 fewer cases of chronic bronchitis, 2,200 fewer non-fatal heart attacks, 2300 fewer hospitalizations (for respiratory and cardiovascular disease combined—admissions and emergency room visits) and result in significant reductions in days of restricted activity due to respiratory illness (with an estimate of one million fewer cases) and approximately 170,000 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.). Since we did not conduct ozone modeling for this rulemaking, we are unable to quantify or monetize the ozone related benefits that will likely result from BART.

Table IV–2 presents the estimated monetary value of reductions in the incidence of health and welfare effects. Annual PM-related health benefits and visibility benefits are estimated to range from approximately $2.2 to $14.3 billion annually. This range of estimates reflects different scenarios about States actions in response to the BART rule and the applicable discount rate (3 percent or 7 percent). Estimated annual visibility benefits in southeastern and southwestern Class I areas range from approximately $80 million to $420 million annually in 2015. All monetized estimates are stated in 1999$. These estimates account for growth in real gross domestic product (GDP) per capita between the present and 2015. As the table indicates, total benefits are driven primarily by the reduction in premature fatalities each year. Reductions in premature mortality account for over 90 percent of total benefits.

Table IV–3 presents the total monetized net benefits for 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 IV–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, but we were unable to estimate the benefits for this rulemaking.

e. Quantified and Monetized Welfare Benefits

Only a subset of the expected visibility benefits—those for Class I areas in the southeastern and southwestern 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 anticipate improvement in visibility in residential areas where people live, work and recreate in the nation for which we are currently unable to monetize benefits. For the Class I areas in the southeastern and southwestern U.S., we estimate annual benefits ranging from $80 to $420 million beginning in 2015 for visibility improvements. The value of visibility benefits in areas where we were unable to monetize benefits could also be substantial.

TABLE IV–1.—CLEAN AIR VISIBILITY RULE: ESTIMATED REDUCTION IN INCIDENCE OF ADVERSE HEALTH EFFECTS IN 2015 [a,b]

Health Effect	Incidence reduction		
	Scenario 1	Scenario 2	Scenario 3
PM-Related Endpoints:			
Premature mortality [c]			
Adult, age 30 and over	400	1,600	2,300
Infant, age <1 year	1	4	5
Chronic bronchitis (adult, age 26 and over)	230	890	1,300
Non-fatal myocardial infarction (adults, age 18 and older)	570	2,200	3,000
Hospital admissions—respiratory (all ages) [d]	140	510	720
Hospital admissions—cardiovascular (adults, age >18) [e]	120	450	640
Emergency room visits for asthma (age 18 years and younger)	370	1,300	1,800
Acute bronchitis (children, age 8–12)	550	2,100	3,000

TABLE IV–1.—CLEAN AIR VISIBILITY RULE: ESTIMATED REDUCTION IN INCIDENCE OF ADVERSE HEALTH EFFECTS IN 2015 [a,b]—Continued

Health Effect	Incidence reduction		
	Scenario 1	Scenario 2	Scenario 3
Lower respiratory symptoms (children, age 7–14)	6,600	25,000	36,000
Upper respiratory symptoms (asthmatic children, age 9–18)	5,000	19,000	27,000
Asthma exacerbation (asthmatic children, age 6–18)	8,100	31,000	44,000
Work loss days (adults, age 18–65)	44,000	170,000	240,000
Minor restricted-activity days (MRADs) (adult age, 18–65)	260,000	1,000,000	1,400,000

[a] Incidences are rounded to two significant digits. These estimates represent benefits from BART nationwide. The modeling used to derive these incidence estimates assumes the final CAIR program in the baseline including the CAIR promulgated rule and the proposal to include SO_2 and annual NO_X controls for New Jersey and Delaware. Modeling used to develop these estimates assumes annual SO_2 and NO_X controls for Arkansas for CAIR resulting in a slight understatement of the reported benefits and costs for BART. The recently promulgated CAMR has not been considered in the baseline for BART.
[b] Ozone benefits are expected for BART, but are not estimated for this analysis.
[c] Adult premature mortality based upon studies by Pope et al., 2002. Infant premature mortality is based upon studies by Woodruff, Grillo, and Schoendorf, 1997.
[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.

TABLE IV–2. ESTIMATED MONETARY VALUE OF REDUCTIONS IN INCIDENCE OF HEALTH AND WELFARE EFFECTS FOR THE CLEAN AIR VISIBILITY RULE IN 2015

[In millions of 1999$] [a,b]

	Scenario 1	Scenario 2	Scenario 3
Health Effects:			
Premature mortality [c,d]			
Adult >30 years			
3 percent discount rate	$2,330	$9,180	$13,000
7 percent discount rate	1,960	7,730	10,900
Infant <1 year	6.12	23.8	34.2
Chronic bronchitis (adults, 26 and over)	90.5	353	498
Nonfatal acute myocardial infarctions			
3 percent discount rate	49.3	189	264
7 percent discount rate	45.8	175	245
Hospital admissions for respiratory causes	1.07	4.03	5.65
Hospital admissions for cardiovascular causes	2.6	10.0	14.1
Acute bronchitis (children, age 8–12)	0.207	0.79	1.12
Lower respiratory symptoms (children, 7–14)	0.109	0.415	0.587
Upper respiratory symptoms (asthma, 9–11)	0.137	0.523	0.74
Emergency Room Visits for Asthma (age 18 years and younger)	0.106	0.362	0.51
Asthma exacerbations	0.367	1.4	1.98
Work loss days	5.56	22.4	31.5
Minor restricted-activity days (MRADs)	13.8	54.1	76.3
Welfare Effects:			
Recreational visibility, 81 Class I areas	84	239	416
Monetized Total [e]			
Base Estimate:			
3 percent discount rate	2,600+B	10,100+B	14,300+B
7 percent discount rate	2,200+B	8,600+B	12,200+B

[a] Monetary benefits are rounded to three significant digits. These estimates are nationwide with the exception of visibility benefits. Visibility benefits relate to Class I areas in the southeastern and southwestern United States. Ozone benefits are expected for BART, but have not been estimated for this analysis. The benefit estimates assume the final CAIR program in the baseline that includes the CAIR promulgated rule and the proposal to include SO_2 and annual NO_X controls for New Jersey and Delaware. Modeling used to develop the CAIR baseline estimates assumes annual SO_2 and NO_X controls for Arkansas resulting in a slight understatement of the reported benefits and costs for BART. The recently promulgated CAMR is not considered in the baseline for BART.
[b] Monetary benefits adjusted to account for growth in real GDP per capita between 1990 and the analysis year of 2015.
[c] Valuation assumes discounting over the SAB-recommended 20-year segmented lag structure described in Chapter 4. Results show 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (U.S. EPA, 2000; OMB, 2003).
[d] Adult premature mortality based upon studies by Pope et al., 2002. Infant premature 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 IV–4. Totals rounded to nearest $100 million, and totals may not sum due to rounding.

TABLE IV–3.—SUMMARY OF ANNUAL BENEFITS, COSTS, AND NET BENEFITS OF THE CLEAN AIR VISIBILITY RULE IN 2015 [a]

[Billions of 1999$]

Description	Scenario 1	Scenario 2	Scenario 3
Social costs [b]			

TABLE IV–3.—SUMMARY OF ANNUAL BENEFITS, COSTS, AND NET BENEFITS OF THE CLEAN AIR VISIBILITY RULE IN 2015[a]—Continued

[Billions of 1999$]

Description	Scenario 1	Scenario 2	Scenario 3
3 percent discount rate	$0.4	$1.4	$2.3
7 percent discount rate	0.3	1.5	2.9
Social benefits[c, d, e]			
3 percent discount rate	2.6 + B	10.1 + B	14.3 + B
7 percent discount rate	2.2 + B	8.6 + B	12.2 + B
Health-related benefits:			
3 percent discount rate	2.5	9.8	13.9
7 percent discount rate	2.1	8.4	11.8
Visibility benefits	0.08	0.24	0.42
Net benefits (benefits-costs)[e, f]			
3 percent discount rate	2.2 + B	8.7 + B	12.0 + B
7 percent discount rate	1.9 + B	7.1 + B	9.3 + B

[a] All estimates are rounded to three significant digits and represent annualized benefits and costs anticipated for the year 2015. Estimates assume a complete CAIR program in the baseline including the CAIR promulgated rule and the proposal to include SO_2 and annual NO_X controls for New Jersey and Delaware. Modeling used to develop the CAIR baseline estimates assumes annual SO_2 and NO_X controls for Arkansas resulting in a slight understatement of the reported benefits and costs for BART. The recently promulgated CAMR is not considered in the baseline for BART.

[b] Note that costs are the annualized total costs of reducing pollutants including NO_X and SO_2 for the EGU source category in areas outside the CAIR region and excluding additional SO_2 controls for the WRAP 309 States of UT, AZ, WY, OR or NM and include costs for non-EGU sources nationwide. The discount rate used to conduct the analysis impacts the control strategies chosen for the non-EGU source category resulting in greater level of controls under the 3 percent discount rate for Scenario 1.

[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. Benefit estimates in this table are nationwide (with the exception of visibility) and reflect NO_X and SO_2 reductions. Ozone benefits are expected to occur for this rule, but are not estimated in this analysis. Visibility benefits represent benefits in Class I areas in the southeastern and southwestern 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 IV–4.

[e] Valuation assumes discounting over the SAB-recommended 20-year segmented lag structure described in Chapter 4. Results reflect 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses (U.S. EPA, 2000; OMB, 2003).

[f] Net benefits are rounded to the nearest $100 million. Columnar totals may not sum due to rounding.

TABLE IV–4.—UNQUANTIFIED AND NONMONETIZED EFFECTS OF THE CLEAN AIR VISIBILITY RULE

Pollutant/effect	Effects not included in primary estimates—changes in:
Ozone—Health[a]	• Premature mortality[b]. • Chronic respiratory damage. • Premature aging of the lungs. • Nonasthma respiratory emergency room visits. • Increased exposure to Uvb. • Hospital Admissions : respiratory. • Emergency room visits for asthma. • Minor restricted activity days. • School loss days. • Asthma attacks. • Cardiovascular emergency room visits. • Acute respiratory symptoms.
Ozone—Welfare	• Yields for: —Commercial forests, —Fruits and vegetables, and —Commercial and noncommercial crops. • Damage to urban ornamental plants. • 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. • Nonasthma 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. • 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.

TABLE IV–4.—UNQUANTIFIED AND NONMONETIZED EFFECTS OF THE CLEAN AIR VISIBILITY RULE—Continued

Pollutant/effect	Effects not included in primary estimates—changes in:
	• Commercial fishing, agriculture, and forests due to nitrogen deposition. • Recreation in estuarine ecosystems due to nitrogen deposition. • Ecosystem functions. • Passive fertilization due to nitrogen deposition.
Mercury Health [g]	• Incidence of neurological disorders. • Incidence of learning disabilities. • Incidence of developmental delays. • Potential reproductive effects[f]. • Potential cardiovascular effects[f], including: —Altered blood pressure regulation [f] —Increased heart rate variability [f] —Incidence of myocardial infarction [f]
Mercury Deposition Welfare [g]	• Impacts on birds and mammals (e.g., reproductive effects). • Impacts to commercial, subsistence, and recreational fishing.

[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, inflammation 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. See discussion in Section 5.3.4 for more details.

[f] These are potential effects as the literature is insufficient.

[g] Mercury emission reductions are not anticipated for BART for the EGU source category due to the cap-and-trade program promulgated for the Clean Air Mercury Rule (March 2005); however, the geographic location of mercury reductions may change as a result of this rule. EPA believes any such effects for these sources would be minimal. Mercury reductions are expected for the non-EGU source categories. The mercury reduction for BART from the non-EGU source categories is expected to be small in comparison to reductions resulting from the recently promulgated Clean Air Interstate Rule and the Clean Air Mercury Rule (March 2005).

3. How Do the Benefits Compare to the Costs of This Final Rule?

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. The social costs of this rule for the EGU and non-EGU sector sources are estimated to range from approximately $0.3 to $2.9 billion in 2015. This range depends upon the control scenario assumed and applicable discount rates of 3 percent and 7 percent. The net benefits (social benefits minus social costs) of the rule range from approximately $1.9 + B billion or $12.0 + B billion depending upon the scenario evaluated and the applicable discount rate (3 and 7 percent) annually in 2015. Implementation of the rule is expected to provide society with a substantial net gain in social welfare based on economic efficiency criteria.

There is uncertainty surrounding the actions States are likely to take to comply with the BART guidelines. States will determine BART-eligible sources based upon CAA criteria, determine those BART-eligible sources reasonably anticipated to cause or contribute to visibility impairment in Class I areas and then apply a 5 factor test for BART determinations. The range of estimated benefits, costs, and resulting net benefits for BART reflects the uncertainty concerning States responses to BART and represents EPA's best estimates of the benefit-cost outcomes of alternative compliance scenarios.

The annualized cost of BART, as quantified here, is EPA's best assessment of the cost of actions States are likely to take to comply with the rule. The EGU portion of these costs are generated from rigorous economic modeling of changes in the power sector due to the BART rule and guidelines. 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 BART rule and guidelines to industry. However, there may exist certain costs that EPA has not quantified in these estimates. These costs may include costs of transitioning to the BART, 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. 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 rule. Although EPA has not quantified these potential additional 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.

The non-EGU portion of these costs are generated from extensive cost modeling based on applying illustrative regulatory scenarios to the non-EGU source categories. These costs represent potential impacts to non-EGU sources from State-imposed BART requirements. The direct cost includes, but is not limited to, capital investments in pollution controls, operating and maintenance expenses of the pollution controls, and additional fuel expenditures. The EPA believes that these costs reflect, as closely as possible, the potential additional costs of the BART rule and guidelines to industries with non-EGU sources. However, there may exist certain costs that EPA has not quantified in these estimates. These costs may include costs of transitioning to the BART rule and guidelines, such as the costs associated with the retirement of smaller or less efficient non-EGUs, employment shifts as workers are retrained at the same company or re-employed elsewhere in the economy, and costs associated with applying both SO_2 and NO_X controls at one facility at the same time. Costs may be understated since the non-EGU cost modeling presumed a least-cost approach, and the potentially 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 industries with potentially affected non-EGU sources. 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 and costs applicable to the non-EGU sectors on the entire economy [*see* Regulatory Impact Analysis for the Final Clean Visibility Rule, Appendix A (June 2005)].

The costs presented here are EPA's best estimate of the direct private costs of the BART rule and guidelines. For purposes of benefit-cost analysis of this rule, EPA has also estimated the additional costs of BART using alternate discount rates for calculating the social costs, parallel to the range of discount rates used in the estimates of the benefits of BART (3 percent and 7 percent). Using these alternate discount rates, the social costs of BART range from $0.3 to $2.9 billion in 2015. (Note the portion of these annual costs associated with non-EGU sources represents incremental private cost estimates that are used as a proxy for the social costs of the rule.)

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:

- Uncertainty concerning actions States will undertake to comply with BART;
- 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.[87]

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 Impact Analysis for the Final Clean Air Visibility Rule (April 2005)]. As Table IV–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.[88] 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 BART rule and guidelines are 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 BART 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 IV–4. These effects are denoted by "B" in Table IV–3 above, and are additive to the estimates of benefits.

[87] 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.

[88] 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.

4. What Are the Unquantified and Unmonetized Benefits of BART 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 IV–4. Some of the more important examples include: Reductions in NO_X and SO_2 emissions required by BART 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 BART: 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.

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 nation. Thus, reductions in the levels of nitrogen deposition will have a positive impact upon current eutrophic conditions in estuaries and coastal areas in the country.

5. Are There Health or Welfare Disbenefits of the BART 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 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.

B. Paperwork Reduction Act

Today's rule clarifies, but does not modify the information collection requirements for BART. Therefore, this action does not impose any new information collection burden. However, the OMB has previously approved the information collection requirements contained in the existing regulations [40 CFR Part 51] under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* and has assigned OMB control number 2060–0421, EPA ICR number 1813.04. A copy of the OMB approved Information Collection Request (ICR) may be obtained from Susan Auby, Collection Strategies Division; U.S. Environmental Protection Agency (2822T); 1200 Pennsylvania Ave., NW, Washington, DC 20460 or by calling (202) 566–1672.

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

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

C. Regulatory Flexibility Act

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

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administrations' regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Table IV–5 lists potentially impacted BART industry source categories and the current applicable small business criteria established by the Small Business Administration.

TABLE IV–5. POTENTIALLY AFFECTED BART SOURCE CATEGORIES AND SMALL BUSINESS SIZE STANDARDS

NAICS [a]	Description	Size standard [b]
221112 [c,d]	Fossil fuel-fired electric utility steam generating units	electric output ≤ 4 million megawatt hours.
212112	Bituminous Coal Underground Mining	500 Employees.
311221	Wet Corn Milling	750 Employees.
311311	Sugarcane Mills	500 Employees.
311313	Beet Sugar Manufacturing	750 Employees.
31214	Distilleries	750 Employees.
321212	Softwood Veneer and Plywood Manufacturing	500 Employees.
322121	Paper (except Newsprint) Mills (pt)	750 Employees.
325188	All Other Basic Inorganic Chemical Manufacturing (pt)	1,000 Employees.
325221	Cellulosic Organic Fiber Manufacturing	1,000 Employees.
325222	Noncellulosic Organic Fiber Manufacturing	1,000 Employees.
325182	Carbon Black Manufacturing (pt)	500 Employees.
327213	Glass Container Manufacturing	750 Employees.
327212	Other Pressed and Blown Glass and Glassware Manufacturing	750 Employees.

TABLE IV–5. POTENTIALLY AFFECTED BART SOURCE CATEGORIES AND SMALL BUSINESS SIZE STANDARDS—Continued

NAICS[a]	Description	Size standard[b]
32731	Cement Manufacturing	750 Employees.
32741	Lime Manufacturing	500 Employees.
331111	Iron and Steel Mills	1,000 Employees.
331315	Aluminum Sheet, Plate, and Foil Manufacturing	750 Employees.
331319	Other Aluminum Rolling and Drawing	750 Employees.
22121	Natural Gas Distribution	500 Employees.

[a] North American Industry Classification System.
[b] Small Business Administration Size Criteria.
[c] Include NAICS categories for source categories that own and operate electric generating units only.
[d] Federal, State, or local government-owned and operated establishments are classified according to the activity in which they are engaged.

After considering the economic impacts of today's final rule on small entities, EPA has concluded that this action will not have a significant economic impact on a substantial number of small entities. This final rule will not impose any direct requirements on small entities. The rule would apply to States, not to small entities.

Courts have interpreted the RFA to require a regulatory flexibility analysis only when small entities will be subject to the requirements of the rule. See *Motor and Equip. Mfrs. Ass'n* v. *Nichols,* 142 F. 3d 449 (D.C. Cir., 1998); *United Distribution Cos.* v. *FERC,* 88 F. 3d 1105, 1170 (D.C. Cir., 1996); *Mid-Tex Elec. Co-op, Inc.* v. *FERC,* 773 F . 2d 327, 342 (D.C. Cir., 1985) (agency's certification need only consider the rule's impact on entities subject to the rule).

BART requirements in the regional haze rule require BART determinations for a select list of major stationary sources defined by section 169A(g)(7) of the CAA. However, as noted in the proposed and final regional haze rules, the State's determination of BART for regional haze involves some State discretion in considering a number of factors set forth in section 169A(g)(2), including the costs of compliance.

Further, the final regional haze rule allows States to adopt alternative measures in lieu of requiring the installation and operation of BART at these major stationary sources. As a result, the potential consequences of the BART provisions of the regional haze rule (as clarified in today's rule) at specific sources are speculative. Any requirements for BART will be established by State rulemakings. The States would accordingly exercise substantial intervening discretion in implementing the BART requirements of the regional haze rule and today's guidelines.

EPA has undertaken an illustrative analysis to assess the potential small business impacts of BART based upon EPA's assessment of the actions States may take to comply with the BART rule and guidelines.

For this final rule, the engineering analysis conducted for the rulemaking identified 491 EGU units potentially affected by the outcome of this rule. Using unit ORIS[89] numbers and the Energy Information Administration's publicly available 2002 electric generator databases (Form EIA 860 and Form EIA 861), we identified utility names, nameplate capacity for affected units, and net electricity generation potentially affected by this rule. After identifying these units, we excluded units that are located in CAIR regions in order to identify those units most likely affected by the BART regulatory program. After an assessment of the ownership of these remaining units, we identified 2 potentially affected small entities in the EGU sector. We used a cost-to-sales approach (comparison of expected annual costs of emission controls to annual sales revenue or government entity budgets for the affected small entity) to assess the potential impacts of BART for these affected entities. Using data from the cost analysis, EPA found one of these small entities may experience a cost-to-sales ratio of 3 percent of sales. The other affected small entity in the EGU sector does not face additional compliance costs associated with the rule.

The engineering analysis conducted for the rulemaking identified over 2,000 records associated with affected non-EGU units (all source categories listed in table IV–5 other than EGUs—NAICS 221112) potentially affected by the rule. Using publicly available sales and employment databases, plant names, and locations, we identified 279 entities and potential owners. In order to classify affected ultimate entities as small or large, EPA collected information on facility names, parent company sales, and parent company employment data. Data were compared with the appropriate size standard and entities were classified as small or large according to Small Business Administration's definitions. For example, ultimate parent companies of cement producers with employment exceeding 750 employees were classified as large companies. This process identified 36 small companies and 195 large companies potentially impacted as a result promulgating this rule. The remaining 48 entities were either government-owned (25 entities, primarily state universities) or parent ownership could not be definitively identified using available databases (23 entities).

Using the cost-to-sales approach described above, EPA found that five non-EGU source category small entities may potentially be affected at or above 3 percent. Two entities may be affected between one and three percent, and the remaining small entity cost-to-sales ratios are below one percent. The median cost-to-sales ratio for non-EGU source category small entities is estimated to be 0.3 percent and could potentially range from 0 to 20 percent. As previously discussed this analysis is illustrative and based upon EPA's assessment of actions States are likely to take as a result of the BART rule and guidelines promulgated today.

D. Unfunded Mandates Reform Act

Title II of the Unfunded Mandates Reform Act of 1995 (Public Law 104–4) establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of 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

[89] An ORIS code is a 4 digit number assigned by the Energy Information Administration (EIA) at the U.S. Department of Energy to power plants owned by utilities.

mandate" is defined under section 421(6), 2 U.S.C. 658(6), to include a "Federal intergovernmental 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). 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 UMRA, section 205, 2 U.S.C. 1535, of 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 RIA prepared by EPA and placed in the docket for this rulemaking is consistent with the requirements of section 202 of the UMRA. Furthermore, 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. Further, EPA carried out consultations with the governmental entities affected by this rule in a manner consistent with the intergovernmental consultation provisions of section 204 of the UMRA.

The EPA also believes that today's rule meets the UMRA requirement in section 205 to select the least costly and burdensome alternative in light of the statutory mandate for BART. As explained above, we are promulgating the BART rule and guidelines following the D.C. Circuit's remand of the BART provisions in the 1999 regional haze rule. The 1999 regional haze rule provides substantial flexibility to the States, allowing them to adopt alternative measures such as a trading program in lieu of requiring the installation and operation of BART. The provisions governing such alternative measures were affected by a more recent decision of the D.C. Circuit and will be revised in a separate rulemaking process. Today's rule will not restrict the ability of the States to adopt such alternatives measures once those revisions to the regional haze rule have been made final. This will provide an alternative to BART that gives States the ability to choose the least costly and least burdensome alternative. Today's rule also allows States affected by the Clean Air Interstate Rule to utilize emission reductions achieved by EGUs under that rule to satisfy BART requirements for those sources. This will provide those States with another cost effective and less burdensome alternative to BART.

The EPA is not reaching a final conclusion as to the applicability of UMRA to today's rulemaking action. The reasons for this are discussed in the 1999 regional haze rule (64 FR 35762) and in the 2001 BART guidelines proposal (66 FR 38111–38112). Notwithstanding this, the discussion in chapter 9 of the RIA constitutes the UMRA statement that would be required by UMRA if its statutory provisions applied. Consequently, we continue to believe that it is not necessary to reach a conclusion as to the applicability of the UMRA requirements.

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." Such policies are defined in the Executive Order to include regulations that have "substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government." Under section 6 of Executive Order 13132, EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the regulation. The EPA also may not issue a regulation that has federalism implications and that preempts State law unless EPA consults with State and local officials early in the process of developing the regulation.

We have concluded that today's action, promulgating the BART guidelines, will not have federalism implications, as specified in section 6 of the Executive Order 13132 (64 FR 43255, August 10, 1999) because it will not have substantial direct effects on the States, nor substantially alter the relationship or the distribution of power and responsibilities between the States and the Federal government. Nonetheless, we consulted with a wide scope of State and local officials, including the National Governors Association, the National League of Cities, the National Conference of State Legislatures, the U. S. Conference of Mayors, the National Association of Counties, the Council of State Governments, the International City/County Management Association, and the National Association of Towns and Townships during the course of developing this rule.

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 defined by Executive Order 13175. It does not have a substantial direct effect on one or more Indian Tribes. 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 address air quality issues, and this rule does nothing to modify that relationship. This rule does not have Tribal implications, and Executive Order 13175 does not apply to this rulemaking.

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

Executive Order 13045, "Protection of Children from Environmental Health Risks and Safety Risks" (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be "economically significant" as defined under Executive Order 12866 and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, Section 5–501 of the Order directs the Agency to evaluate the environmental health or safety effects of the planned rule on children and to explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency.

EPA interprets Executive Order 13045 as applying only to those regulatory actions that are based on health and safety risks, such that the analysis required under section 5–501 of the

Order has the potential to influence the regulation. The BART rule and guidelines are not subject to the Executive Order because the rule and guidelines do not involve decisions on environmental health or safety risks that may disproportionately affect children. The EPA believes that the emissions reductions from the control strategies considered in this rulemaking will further improve air quality and will further improve children's health.

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

We have conducted a Regulatory Impact Analysis for this rule, that includes an analysis of energy impacts and is contained in the docket (Docket No. OAR–2002–0076). This rule is not a "significant energy action" as defined in Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355 (May 22, 2001)) because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. This rule is not a "significant energy action," because it will have less than a 1 percent impact on the cost of energy production and does not exceed other factors described by OMB that may indicate a significant adverse effect. (See, "Guidance for Implementing E.O. 13211," OMB Memorandum 01–27 (July 13, 2001) *http://www.whitehouse.gov/omb/memoranda/m01–27.html.)* Specifically, the presumptive requirements for EGUs for this rule, when fully implemented, are expected have a 0.25 percent impact on the cost of energy production for the nation in 2015. States must use the guidelines in making BART determinations for power plants with a generating capacity in excess of 750 MW. Our analysis evaluates the impact of the presumptive requirements for these sources and does not consider any possible additional controls for EGU sources or non-EGU sources that States may require. Although States may choose to use the guidelines in establishing BART limits for non-EGUs , ultimately States will determine the sources subject to BART and the appropriate level of control for such sources.

We are finalizing today's rule following the D.C. Circuit's remand of the BART provisions in the 1999 regional haze rule. The 1999 regional haze rule provides substantial flexibility to the States, allowing them to adopt alternative measures such as a trading program in lieu of requiring the installation and operation of BART. The provisions governing such alternative measures were affected by a more recent decision of the D.C. Circuit and will be revised in a separate rulemaking process. This rulemaking will not restrict the ability of the States to adopt alternative measures once those revisions to the regional haze rule have been made final. This will provide an alternative to BART that reduces the overall cost of the regulation and its impact on the energy supply. Today's rule also allows States affected by the Clean Air Interstate Rule to utilize emission reductions achieved by EGUs under that rule to satisfy BART requirements for those sources. This will provide those States with another cost effective and less burdensome alternative to BART. The BART rule itself offers flexibility by offering the choice of meeting SO_2 requirements between an emission rate and a removal rate.

For a State that chooses to require case-by-case BART, today's rule would establish presumptive levels of controls for SO_2 and NO_X for certain EGUs that the State finds are subject to BART. Based on its consideration of various factors set forth in the regulations; however, a State may conclude that a different level of control is appropriate. The States will accordingly exercise substantial intervening discretion in implementing the final rule. Additionally, we have assessed that the compliance dates for the rule will provide adequate time for EGUs to install the required emission controls.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer Advancement Act of 1995 (NTTAA), Public Law 104–113, section 12(d)(15 U.S.C. 272 note) directs EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. The NTTAA directs EPA to provide Congress, through OMB, explanations when the EPA decides not to use VCS.

This action does not involve technical standards; thus, EPA did not consider the use of any VCS.

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,[90] 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. Negative impacts to these sub-populations that appreciably exceed similar impacts to the general population are not expected because the Agency expects this rule to lead to reductions in air pollution emissions and exposures generally.

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).

List of Subjects in 40 CFR Part 51

Environmental protection, Air pollution control, Administrative practice and procedure, Intergovernmental relations, Lead, Nitrogen dioxide, Ozone, Particulate matter, Reporting and recordkeeping

[90] U.S. Environmental Protection Agency, 1998. Guidance for Incorporating Environmental Justice Concerns in EPA's NEPA Compliance Analyses. Office of Federal Activities, Washington, D.C., April, 1998.

requirements, Sulfur oxides, Volatile organic compounds.

Dated: June 15, 2005.

Stephen L. Johnson,

Administrator.

■ For the reasons set forth in the preamble, part 51 of chapter I of title 40 of the Code of Federal Regulations is amended as follows:

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

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

Authority: 23 U.S.C. 101; 42 U.S.C. 7410–7671q.

■ 2. Section 51.302 is amended by revising paragraph (c)(4)(iii) to read as follows:

§ 51.302 Implementation control strategies for reasonably attributable visibility impairment.

* * * * *

(c) * * *

(4) * * *

(iii) BART must be determined for fossil-fuel fired generating plants having a total generating capacity in excess of 750 megawatts pursuant to "Guidelines for Determining Best Available Retrofit Technology for Coal-fired Power Plants and Other Existing Stationary Facilities" (1980), which is incorporated by reference, exclusive of appendix E to the Guidelines, except that options more stringent than NSPS must be considered. Establishing a BART emission limitation equivalent to the NSPS level of control is not a sufficient basis to avoid the analysis of control options required by the guidelines. This document is EPA publication No. 450/3–80–009b and has been approved for incorporation by reference by the Director of the Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. It is for sale from the U.S. Department of Commerce, National Technical Information Service, 5285 Port Royal Road, Springfield, Virginia 22161. It is also available for inspection from the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal_register/index.html.*

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■ 3. Section 51.308 is amended by revising paragraph (b), removing and reserving paragraph (c), revising paragraphs (e)(1)(ii), (e)(3), and (e)(4), and adding paragaphs (e)(5) and (6) to read as follows:

§ 51.308 Regional haze program requirements.

* * * * *

(b) *When are the first implementation plans due under the regional haze program?* Except as provided in § 51.309(c), each State identified in § 51.300(b)(3) must submit, for the entire State, an implementation plan for regional haze meeting the requirements of paragraphs (d) and (e) of this section no later than December 17, 2007.

(c) [Reserved]

* * * * *

(e) * * *

(1) * * *

(ii) A determination of BART for each BART-eligible source in the State that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area. All such sources are subject to BART.

(A) The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

(B) The determination of BART for fossil-fuel fired power plants having a total generating capacity greater than 750 megawatts must be made pursuant to the guidelines in appendix Y of this part (Guidelines for BART Determinations Under the Regional Haze Rule).

(C) *Exception.* A State is not required to make a determination of BART for SO_2 or for NO_X if a BART-eligible source has the potential to emit less than 40 tons per year of such pollutant(s), or for PM_{10} if a BART-eligible source emits less than 15 tons per year of such pollutant.

* * * * *

(3) A State which opts under 40 CFR 51.308(e)(2) to implement an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART may satisfy the final step of the demonstration required by that section as follows: If the distribution of emissions is not substantially different than under BART, and the alternative measure results in greater emission reductions, then the alternative measure may be deemed to achieve greater reasonable progress. If the distribution of emissions is significantly different, the State must conduct dispersion modeling to determine differences in visibility between BART and the trading program for each impacted Class I area, for the worst and best 20 percent of days. The modeling would demonstrate "greater reasonable progress" if both of the following two criteria are met:

(i) Visibility does not decline in any Class I area, and

(ii) There is an overall improvement in visibility, determined by comparing the average differences between BART and the alternative over all affected Class I areas.

(4) A State that opts to participate in the Clean Air Interstate Rule cap-and-trade and trade program under part 96 AAA–EEE need not require affected BART-eligible EGU's 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.

(5) After a State has met the requirements for BART or implemented emissions trading program or other alternative measure that achieves more reasonable progress than the installation and operation of BART, BART-eligible sources will be subject to the requirements of paragraph (d) of this section in the same manner as other sources.

(6) Any BART-eligible facility subject to the requirement under paragraph (e) of this section to install, operate, and maintain BART may apply to the Administrator for an exemption from that requirement. An application for an exemption will be subject to the requirements of § 51.303(a)(2)–(h).

* * * * *

■ 4. Appendix Y to Part 51 is added to read as follows:

Appendix Y to Part 51—Guidelines for BART Determinations Under the Regional Haze Rule

Table of Contents

I. Introduction and Overview

A. What is the purpose of the guidelines?

The Clean Air Act (CAA), in sections 169A and 169B, contains requirements for the protection of visibility in 156 scenic areas across the United States. To meet the CAA's requirements, we published regulations to protect against a particular type of visibility impairment known as "regional haze." The regional haze rule is found in this part at 40 CFR 51.300 through 51.309. These regulations require, in 40 CFR 51.308(e), that certain types of existing stationary sources of air pollutants install best available retrofit technology (BART). The guidelines are designed to help States and others (1) identify those sources that must comply with the BART requirement, and (2) determine the level of control technology that represents BART for each source.

B. What does the CAA require generally for improving visibility?

Section 169A of the CAA, added to the CAA by the 1977 amendments, requires States to protect and improve visibility in certain scenic areas of national importance. The scenic areas protected by section 169A are "the mandatory Class I Federal Areas * * * where visibility is an important value." In these guidelines, we refer to these as "Class I areas." There are 156 Class I areas, including 47 national parks (under the jurisdiction of the Department of Interior—National Park Service), 108 wilderness areas (under the jurisdiction of the Department of the Interior—Fish and Wildlife Service or the Department of Agriculture—U.S. Forest Service), and one International Park (under the jurisdiction of the Roosevelt-Campobello International Commission). The Federal Agency with jurisdiction over a particular Class I area is referred to in the CAA as the Federal Land Manager. A complete list of the Class I areas is contained in 40 CFR 81.401 through 81.437, and you can find a map of the Class I areas at the following Internet site: *http://www.epa.gov/ttn/oarpg/t1/fr_notices/classimp.gif*.

The CAA establishes a national goal of eliminating man-made visibility impairment from all Class I areas. As part of the plan for achieving this goal, the visibility protection provisions in the CAA mandate that EPA issue regulations requiring that States adopt measures in their State implementation plans (SIPs), including long-term strategies, to provide for reasonable progress towards this national goal. The CAA also requires States to coordinate with the Federal Land Managers as they develop their strategies for addressing visibility.

C. What is the BART requirement in the CAA?

1. Under section 169A(b)(2)(A) of the CAA, States must require certain existing stationary sources to install BART. The BART provision applies to "major stationary sources" from 26 identified source categories which have the potential to emit 250 tons per year or more of any air pollutant. The CAA requires only sources which were put in place during a specific 15-year time interval to be subject to BART. The BART provision applies to sources that existed as of the date of the 1977 CAA amendments (that is, August 7, 1977) but which had not been in operation for more than 15 years (that is, not in operation as of August 7, 1962).

2. The CAA requires BART review when any source meeting the above description "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility" in any Class I area. In identifying a level of control as BART, States are required by section 169A(g) of the CAA to consider:

(a) The costs of compliance,

(b) The energy and non-air quality environmental impacts of compliance,

(c) Any existing pollution control technology in use at the source,

(d) The remaining useful life of the source, and

(e) The degree of visibility improvement which may reasonably be anticipated from the use of BART.

3. The CAA further requires States to make BART emission limitations part of their SIPs. As with any SIP revision, States must provide an opportunity for public comment on the BART determinations, and EPA's action on any SIP revision will be subject to judicial review.

D. What types of visibility problems does EPA address in its regulations?

1. We addressed the problem of visibility in two phases. In 1980, we published regulations addressing what we termed "reasonably attributable" visibility impairment. Reasonably attributable visibility impairment is the result of emissions from one or a few sources that are generally located in close proximity to a specific Class I area. The regulations addressing reasonably attributable visibility impairment are published in 40 CFR 51.300 through 51.307.

2. On July 1, 1999, we amended these regulations to address the second, more common, type of visibility impairment known as "regional haze." Regional haze is the result of the collective contribution of many sources over a broad region. The regional haze rule slightly modified 40 CFR 51.300 through 51.307, including the addition of a few definitions in § 51.301, and added new §§ 51.308 and 51.309.

E. What are the BART requirements in EPA's regional haze regulations?

1. In the July 1, 1999 rulemaking, we added a BART requirement for regional haze. We amended the BART requirements in 2005. You will find the BART requirements in 40 CFR 51.308(e). Definitions of terms used in 40 CFR 51.308(e)(1) are found in 40 CFR 51.301.

2. As we discuss in detail in these guidelines, the regional haze rule codifies and clarifies the BART provisions in the CAA. The rule requires that States identify and list "BART-eligible sources," that is, that States identify and list those sources that fall within the 26 source categories, were put in place during the 15-year window of time from 1962 to 1977, and have potential

emissions greater than 250 tons per year. Once the State has identified the BART-eligible sources, the next step is to identify those BART-eligible sources that may "emit any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility." Under the rule, a source which fits this description is "subject to BART." For each source subject to BART, 40 CFR 51.308(e)(1)(ii)(A) requires that States identify the level of control representing BART after considering the factors set out in CAA section 169A(g), as follows:

—States must identify the best system of continuous emission control technology for each source subject to BART taking into account the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of visibility improvement that may be expected from available control technology.

3. After a State has identified the level of control representing BART (if any), it must establish an emission limit representing BART and must ensure compliance with that requirement no later than 5 years after EPA approves the SIP. States may establish design, equipment, work practice or other operational standards when limitations on measurement technologies make emission standards infeasible.

F. What is included in the guidelines?

1. The guidelines provide a process for making BART determinations that States can use in implementing the regional haze BART requirements on a source-by-source basis, as provided in 40 CFR 51.308(e)(1). States must follow the guidelines in making BART determinations on a source-by-source basis for 750 megawatt (MW) power plants but are not required to use the process in the guidelines when making BART determinations for other types of sources.

2. The BART analysis process, and the contents of these guidelines, are as follows:

(a) *Identification of all BART-eligible sources.* Section II of these guidelines outlines a step-by-step process for identifying BART-eligible sources.

(b) *Identification of sources subject to BART.* As noted above, sources "subject to BART" are those BART-eligible sources which "emit a pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any Class I area." We discuss considerations for identifying sources subject to BART in section III of the guidance.

(c) *The BART determination process.* For each source subject to BART, the next step is to conduct an analysis of emissions control alternatives. This step includes the identification of available, technically feasible retrofit technologies, and for each technology identified, an analysis of the cost of compliance, the energy and non-air quality environmental impacts, and the degree of visibility improvement in affected Class I areas resulting from the use of the control technology. As part of the BART analysis, the State should also take into account the remaining useful life of the source and any existing control technology present at the source. For each source, the State will determine a "best system of continuous emission reduction" based upon its evaluation of these factors. Procedures for the BART determination step are described in section IV of these guidelines.

(d) *Emissions limits.* States must establish emission limits, including a deadline for compliance, consistent with the BART determination process for each source subject to BART. Considerations related to these limits are discussed in section V of these guidelines.

G. Who is the target audience for the guidelines?

1. The guidelines are written primarily for the benefit of State, local and Tribal agencies, and describe a process for making the BART determinations and establishing the emission limitations that must be included in their SIPs or Tribal implementation plans (TIPs). Throughout the guidelines, which are written in a question and answer format, we ask questions "How do I * * *?" and answer with phrases "you should * * *, you must * * *" The "you" means a State, local or Tribal agency conducting the analysis. We have used this format to make the guidelines simpler to understand, but we recognize that States have the authority to require source owners to assume part of the analytical burden, and that there will be differences in how the supporting information is collected and documented. We also recognize that data collection, analysis, and rule development may be performed by Regional Planning Organizations, for adoption within each SIP or TIP.

2. The preamble to the 1999 regional haze rule discussed at length the issue of Tribal implementation of the requirements to submit a plan to address visibility. As explained there, requirements related to visibility are among the programs for which Tribes may be determined eligible and receive authorization to implement under the "Tribal Authority Rule" ("TAR") (40 CFR 49.1 through 49.11). Tribes are not subject to the deadlines for submitting visibility implementation plans and may use a modular approach to CAA implementation. We believe there are very few BART-eligible sources located on Tribal lands. Where such sources exist, the affected Tribe may apply for delegation of implementation authority for this rule, following the process set forth in the TAR.

H. Do EPA regulations require the use of these guidelines?

Section 169A(b) requires us to issue guidelines for States to follow in establishing BART emission limitations for fossil-fuel fired power plants having a capacity in excess of 750 megawatts. This document fulfills that requirement, which is codified in 40 CFR 51.308(e)(1)(ii)(B). The guidelines establish an approach to implementing the requirements of the BART provisions of the regional haze rule; we believe that these procedures and the discussion of the requirements of the regional haze rule and the CAA should be useful to the States. For sources other than 750 MW power plants, however, States retain the discretion to adopt approaches that differ from the guidelines.

II. How to Identify BART-Eligible Sources

This section provides guidelines on how to identify BART-eligible sources. A BART-eligible source is an existing stationary source in any of 26 listed categories which meets criteria for startup dates and potential emissions.

A. What are the steps in identifying BART-eligible sources?

Figure 1 shows the steps for identifying whether the source is a "BART-eligible source:"

Step 1: Identify the emission units in the BART categories,

Step 2: Identify the start-up dates of those emission units, and

Step 3: Compare the potential emissions to the 250 ton/yr cutoff.

Figure 1. How to determine whether a source is BART-eligible:

Step 1: Identify emission units in the BART categories

Does the plant contain emissions units in one or more of the 26 source categories?

➔ No ➔ Stop

➔ Yes ➔ Proceed to Step 2

Step 2: Identify the start-up dates of these emission units

Do any of these emissions units meet the following two tests?

In existence on August 7, 1977

AND

Began operation after August 7, 1962

➔ No ➔ Stop

➔ Yes ➔ Proceed to Step 3

Step 3: Compare the potential emissions from these emission units to the 250 ton/yr cutoff

Identify the "stationary source" that includes the emission units you identified in Step 2.

Add the current potential emissions from all the emission units identified in Steps 1 and 2 that are included within the "stationary source" boundary.

Are the potential emissions from these units 250 tons per year or more for any visibility-impairing pollutant?

➔ No ➔ Stop

➔ Yes ➔ These emissions units comprise the "BART-eligible source."

1. Step 1: Identify Emission Units in the BART Categories

1. The BART requirement only applies to sources in specific categories listed in the CAA. The BART requirement does not apply to sources in other source categories, regardless of their emissions. The listed categories are:

(1) Fossil-fuel fired steam electric plants of more than 250 million British thermal units (BTU) per hour heat input,

(2) Coal cleaning plants (thermal dryers),

(3) Kraft pulp mills,

(4) Portland cement plants,

(5) Primary zinc smelters,

(6) Iron and steel mill plants,

(7) Primary aluminum ore reduction plants,

(8) Primary copper smelters,
(9) Municipal incinerators capable of charging more than 250 tons of refuse per day,
(10) Hydrofluoric, sulfuric, and nitric acid plants,
(11) Petroleum refineries,
(12) Lime plants,
(13) Phosphate rock processing plants,
(14) Coke oven batteries,
(15) Sulfur recovery plants,
(16) Carbon black plants (furnace process),
(17) Primary lead smelters,
(18) Fuel conversion plants,
(19) Sintering plants,
(20) Secondary metal production facilities,
(21) Chemical process plants,
(22) Fossil-fuel boilers of more than 250 million BTUs per hour heat input,
(23) Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,
(24) Taconite ore processing facilities,
(25) Glass fiber processing plants, and
(26) Charcoal production facilities.

2. Some plants may have emission units from more than one category, and some emitting equipment may fit into more than one category. Examples of this situation are sulfur recovery plants at petroleum refineries, coke oven batteries and sintering plants at steel mills, and chemical process plants at refineries. For Step 1, you identify all of the emissions units at the plant that fit into one or more of the listed categories. You do not identify emission units in other categories.

Example: A mine is collocated with an electric steam generating plant and a coal cleaning plant. You would identify emission units associated with the electric steam generating plant and the coal cleaning plant, because they are listed categories, but not the mine, because coal mining is not a listed category.

3. The category titles are generally clear in describing the types of equipment to be listed. Most of the category titles are very broad descriptions that encompass all emission units associated with a plant site (for example, "petroleum refining" and "kraft pulp mills"). This same list of categories appears in the PSD regulations. States and source owners need not revisit any interpretations of the list made previously for purposes of the PSD program. We provide the following clarifications for a few of the category titles:

(1) *"Steam electric plants of more than 250 million BTU/hr heat input."* Because the category refers to "plants," we interpret this category title to mean that boiler capacities should be aggregated to determine whether the 250 million BTU/hr threshold is reached. This definition includes only those plants that generate electricity for sale. Plants that cogenerate steam and electricity also fall within the definition of "steam electric plants". Similarly, combined cycle turbines are also considered "steam electric plants" because such facilities incorporate heat recovery steam generators. Simple cycle turbines, in contrast, are not "steam electric plants" because these turbines typically do not generate steam.

Example: A stationary source includes a steam electric plant with three 100 million BTU/hr boilers. Because the aggregate capacity exceeds 250 million BTU/hr for the "plant," these boilers would be identified in Step 2.

(2) *"Fossil-fuel boilers of more than 250 million BTU/hr heat input."* We interpret this category title to cover only those boilers that are individually greater than 250 million BTU/hr. However, an individual boiler smaller than 250 million BTU/hr should be subject to BART if it is an integral part of a process description at a plant that is in a different BART category—for example, a boiler at a Kraft pulp mill that, in addition to providing steam or mechanical power, uses the waste liquor from the process as a fuel. In general, if the process uses any by-product of the boiler and the boiler's function is to serve the process, then the boiler is integral to the process and should be considered to be part of the process description.

Also, you should consider a multi-fuel boiler to be a "fossil-fuel boiler" if it burns any amount of fossil fuel. You may take federally and State enforceable operational limits into account in determining whether a multi-fuel boiler's fossil fuel capacity exceeds 250 million Btu/hr.

(3) *"Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels."* The 300,000 barrel cutoff refers to total facility-wide tank capacity for tanks that were put in place within the 1962–1977 time period, and includes gasoline and other petroleum-derived liquids.

(4) *"Phosphate rock processing plants."* This category descriptor is broad, and includes all types of phosphate rock processing facilities, including elemental phosphorous plants as well as fertilizer production plants.

(5) *"Charcoal production facilities."* We interpret this category to include charcoal briquet manufacturing and activated carbon production.

(6) *"Chemical process plants."* and pharmaceutical manufacturing. Consistent with past policy, we interpret the category "chemical process plants" to include those facilities within the 2-digit Standard Industrial Classification (SIC) code 28. Accordingly, we interpret the term "chemical process plants" to include pharmaceutical manufacturing facilities.

(7) *"Secondary metal production."* We interpret this category to include nonferrous metal facilities included within SIC code 3341, and secondary ferrous metal facilities that we also consider to be included within the category "iron and steel mill plants."

(8) *"Primary aluminum ore reduction."* We interpret this category to include those facilities covered by 40 CFR 60.190, the new source performance standard (NSPS) for primary aluminum ore reduction plants. This definition is also consistent with the definition at 40 CFR 63.840.

2. Step 2: Identify the Start-Up Dates of the Emission Units

1. Emissions units listed under Step 1 are BART-eligible only if they were "in existence" on August 7, 1977 but were not "in operation" before August 7, 1962.

What does "in existence on August 7, 1977" mean?

2. The regional haze rule defines "in existence" to mean that:

"the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be canceled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time." 40 CFR 51.301.

As this definition is essentially identical to the definition of "commence construction" as that term is used in the PSD regulations, the two terms mean the same thing. *See* 40 CFR 51.165(a)(1)(xvi) and 40 CFR 52.21(b)(9). Under this definition, an emissions unit could be "in existence" even if it did not begin operating until several years after 1977.

Example: The owner of a source obtained all necessary permits in early 1977 and entered into binding construction agreements in June 1977. Actual on-site construction began in late 1978, and construction was completed in mid-1979. The source began operating in September 1979. The emissions unit was "in existence" as of August 7, 1977.

Major stationary sources which commenced construction AFTER August 7, 1977 (*i.e.*, major stationary sources which were not "in existence" on August 7, 1977) were subject to new source review (NSR) under the PSD program. Thus, the August 7, 1977 "in existence" test is essentially the same thing as the identification of emissions units that were grandfathered from the NSR review requirements of the 1977 CAA amendments.

3. Sources are not BART-eligible if the only change at the plant during the relevant time period was the addition of pollution controls. For example, if the only change at a copper smelter during the 1962 through 1977 time period was the addition of acid plants for the reduction of SO_2 emissions, these emission controls would not by themselves trigger a BART review.

What does "in operation before August 7, 1962" mean?

An emissions unit that meets the August 7, 1977 "in existence" test is not BART-eligible if it was in operation before August 7, 1962. "In operation" is defined as "engaged in activity related to the primary design function of the source." This means that a source must have begun actual operations by August 7, 1962 to satisfy this test.

Example: The owner or operator entered into binding agreements in 1960. Actual on-site construction began in 1961, and construction was complete in mid-1962. The source began operating in September 1962. The emissions unit *was not* "in operation" before August 7, 1962 and is therefore subject to BART.

What is a "reconstructed source?"

1. Under a number of CAA programs, an existing source which is completely or

substantially rebuilt is treated as a new source. Such "reconstructed" sources are treated as new sources as of the time of the reconstruction. Consistent with this overall approach to reconstructions, the definition of BART-eligible facility (reflected in detail in the definition of "existing stationary facility") includes consideration of sources that were in operation before August 7, 1962, but were reconstructed during the August 7, 1962 to August 7, 1977 time period.

2. Under the regional haze regulations at 40 CFR 51.301, a reconstruction has taken place if "the fixed capital cost of the new component exceeds 50 percent of the fixed capital cost of a comparable entirely new source." The rule also states that "[a]ny final decision as to whether reconstruction has occurred must be made in accordance with the provisions of §§ 60.15 (f)(1) through (3) of this title." "[T]he provisions of §§ 60.15(f)(1) through (3)" refers to the general provisions for New Source Performance Standards (NSPS). Thus, the same policies and procedures for identifying reconstructed "affected facilities" under the NSPS program must also be used to identify reconstructed "stationary sources" for purposes of the BART requirement.

3. You should identify reconstructions on an emissions unit basis, rather than on a plantwide basis. That is, you need to identify only the reconstructed emission units meeting the 50 percent cost criterion. You should include reconstructed emission units in the list of emission units you identified in Step 1. You need consider as possible reconstructions only those emissions units with the potential to emit more than 250 tons per year of any visibility-impairing pollutant.

4. The "in operation" and "in existence" tests apply to reconstructed sources. If an emissions unit was reconstructed and began actual operation before August 7, 1962, it is not BART-eligible. Similarly, any emissions unit for which a reconstruction "commenced" after August 7, 1977, is not BART-eligible.

How are modifications treated under the BART provision?

1. The NSPS program and the major source NSR program both contain the concept of modifications. In general, the term "modification" refers to any physical change or change in the method of operation of an emissions unit that results in an increase in emissions.

2. The BART provision in the regional haze rule contains no explicit treatment of modifications or how modified emissions units, previously subject to the requirement to install best available control technology (BACT), lowest achievable emission rate (LAER) controls, and/or NSPS are treated under the rule. As the BART requirements in the CAA do not appear to provide any exemption for sources which have been modified since 1977, the best interpretation of the CAA visibility provisions is that a subsequent modification does not change a unit's construction date for the purpose of BART applicability. Accordingly, if an emissions unit began operation before 1962, it is not BART-eligible if it was modified between 1962 and 1977, so long as the modification is not also a "reconstruction." On the other hand, an emissions unit which began operation within the 1962–1977 time window, but was modified after August 7, 1977, is BART-eligible. We note, however, that if such a modification was a major modification that resulted in the installation of controls, the State will take this into account during the review process and may find that the level of controls already in place are consistent with BART.

3. Step 3: Compare the Potential Emissions to the 250 Ton/Yr Cutoff

The result of Steps 1 and 2 will be a list of emissions units at a given plant site, including reconstructed emissions units, that are within one or more of the BART categories and that were placed into operation within the 1962–1977 time window. The third step is to determine whether the total emissions represent a current potential to emit that is greater than 250 tons per year of any single visibility impairing pollutant. Fugitive emissions, to the extent quantifiable, must be counted. In most cases, you will add the potential emissions from all emission units on the list resulting from Steps 1 and 2. In a few cases, you may need to determine whether the plant contains more than one "stationary source" as the regional haze rule defines that term, and as we explain further below.

What pollutants should I address?

Visibility-impairing pollutants include the following:

(1) Sulfur dioxide (SO_2),
(2) Nitrogen oxides (NO_X), and
(3) Particulate matter.

You may use PM_{10} as an indicator for particulate matter in this intial step. [Note that we do not recommend use of total suspended particulates (TSP) as in indicator for particulate matter.] As emissions of PM_{10} include the components of $PM_{2.5}$ as a subset, there is no need to have separate 250 ton thresholds for PM_{10} and $PM_{2.5}$; 250 tons of PM_{10} represents at most 250 tons of $PM_{2.5}$, and at most 250 tons of any individual particulate species such as elemental carbon, crustal material, etc.

However, if you determine that a source of particulate matter is BART-eligible, it will be important to distinguish between the fine and coarse particle components of direct particulate emissions in the remainder of the BART analysis, including for the purpose of modeling the source's impact on visibility. This is because although both fine and coarse particulate matter contribute to visibility impairment, the long-range transport of fine particles is of particular concern in the formation of regional haze. Thus, for example, air quality modeling results used in the BART determination will provide a more accurate prediction of a source's impact on visibility if the inputs into the model account for the relative particle size of any directly emitted particulate matter (*i.e.* PM_{10} vs. $PM_{2.5}$).

You should exercise judgment in deciding whether the following pollutants impair visibility in an area:

(4) Volatile organic compounds (VOC), and
(5) Ammonia and ammonia compounds.

You should use your best judgment in deciding whether VOC or ammonia emissions from a source are likely to have an impact on visibility in an area. Certain types of VOC emissions, for example, are more likely to form secondary organic aerosols than others.[1] Similarly, controlling ammonia emissions in some areas may not have a significant impact on visibility. You need not provide a formal showing of an individual decision that a source of VOC or ammonia emissions is not subject to BART review. Because air quality modeling may not be feasible for individual sources of VOC or ammonia, you should also exercise your judgement in assessing the degree of visibility impacts due to emissions of VOC and emissions of ammonia or ammonia compounds. You should fully document the basis for judging that a VOC or ammonia source merits BART review, including your assessment of the source's contribution to visibility impairment.

What does the term "potential" emissions mean?

The regional haze rule defines potential to emit as follows:

"Potential to emit" means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

The definition of "potential to emit" means that a source which actually emits less than 250 tons per year of a visibility-impairing pollutant is BART-eligible if its emissions would exceed 250 tons per year when operating at its maximum capacity given its physical and operational design (and considering all federally enforceable and State enforceable permit limits.)

Example: A source, while operating at one-fourth of its capacity, emits 75 tons per year of SO_2. If it were operating at 100 percent of its maximum capacity, the source would emit 300 tons per year. Because under the above definition such a source would have "potential" emissions that exceed 250 tons per year, the source (if in a listed category and built during the 1962–1977 time window) would be BART-eligible.

How do I identify whether a plant has more than one "stationary source?"

1. The regional haze rule, in 40 CFR 51.301, defines a stationary source as a "building, structure, facility or installation which emits or may emit any air pollutant." [2]

[1] *Fine particles: Overview of Atmospheric Chemistry, Sources of Emissions, and Ambient Monitoring Data,* Memorandum to Docket OAR 2002–006, April 1, 2005.

[2] **Note:** Most of these terms and definitions are the same for regional haze and the 1980 visibility regulations. For the regional haze rule we use the term "BART-eligible source" rather than "existing stationary facility" to clarify that only a limited subset of existing stationary sources are subject to BART.

The rule further defines "building, structure or facility" as:

all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities must be considered as part of the same industrial grouping if they belong to the same Major Group (*i.e.*, which have the same two-digit code) as described in the Standard Industrial Classification Manual, 1972 as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101–0066 and 003–005–00176–0, respectively).

2. In applying this definition, it is necessary to determine which facilities are located on "contiguous or adjacent properties." Within this contiguous and adjacent area, it is also necessary to group those emission units that are under "common control." We note that these plant boundary issues and "common control" issues are very similar to those already addressed in implementation of the title V operating permits program and in NSR.

3. For emission units within the "contiguous or adjacent" boundary and under common control, you must group emission units that are within the same industrial grouping (that is, associated with the same 2-digit SIC code) in order to define the stationary source.[3] For most plants on the BART source category list, there will only be one 2-digit SIC that applies to the entire plant. For example, all emission units associated with kraft pulp mills are within SIC code 26, and chemical process plants will generally include emission units that are all within SIC code 28. The "2-digit SIC test" applies in the same way as the test is applied in the major source NSR programs.[4]

4. For purposes of the regional haze rule, you must group emissions from all emission units put in place within the 1962–1977 time period that are within the 2-digit SIC code, even if those emission units are in different categories on the BART category list.

Examples: A chemical plant which started operations within the 1962 to 1977 time period manufactures hydrochloric acid (within the category title "Hydrochloric, sulfuric, and nitric acid plants") and various organic chemicals (within the category title "chemical process plants"). All of the emission units are within SIC code 28 and, therefore, all the emission units are considered in determining BART eligibility of the plant. You sum the emissions over all of these emission units to see whether there are more than 250 tons per year of potential emissions.

A steel mill which started operations within the 1962 to 1977 time period includes a sintering plant, a coke oven battery, and various other emission units. All of the emission units are within SIC code 33. You sum the emissions over all of these emission units to see whether there are more than 250 tons per year of potential emissions.

4. Final Step: Identify the Emissions Units and Pollutants That Constitute the BART-Eligible Source

If the emissions from the list of emissions units at a stationary source exceed a potential to emit of 250 tons per year for any visibility-impairing pollutant, then that collection of emissions units is a BART-eligible source.

Example: A stationary source comprises the following two emissions units, with the following potential emissions:

Emissions unit A
- 200 tons/yr SO_2
- 150 tons/yr NO_X
- 25 tons/yr PM

Emissions unit B
- 100 tons/yr SO_2
- 75 tons/yr NO_X
- 10 tons/yr PM

For this example, potential emissions of SO_2 are 300 tons/yr, which exceeds the 250 tons/yr threshold. Accordingly, the entire "stationary source", that is, emissions units A and B, may be subject to a BART review for SO_2, NO_X, and PM, even though the potential emissions of PM and NO_X at each emissions unit are less than 250 tons/yr each.

Example: The total potential emissions, obtained by adding the potential emissions of all emission units in a listed category at a plant site, are as follows:

200 tons/yr SO_2
150 tons/yr NO_X
25 tons/yr PM

Even though total emissions exceed 250 tons/yr, no individual regulated pollutant exceeds 250 tons/yr and this source is not BART-eligible.

Can States establish de minimis levels of emissions for pollutants at BART-eligible sources?

In order to simplify BART determinations, States may choose to identify de minimis levels of pollutants at BART-eligible sources (but are not required to do so). De minimis values should be identified with the purpose of excluding only those emissions so minimal that they are unlikely to contribute to regional haze. Any de minimis values that you adopt must not be higher than the PSD applicability levels: 40 tons/yr for SO_2 and NO_X and 15 tons/yr for PM_{10}. These de minimis levels may only be applied on a plant-wide basis.

III. How to Identify Sources "Subject to BART"

Once you have compiled your list of BART-eligible sources, you need to determine whether (1) to make BART determinations for all of them or (2) to consider exempting some of them from BART because they may not reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. If you decide to make BART determinations for all the BART-eligible sources on your list, you should work with your regional planning organization (RPO) to show that, collectively, they cause or contribute to visibility impairment in at least one Class I area. You should then make individual BART determinations by applying the five statutory factors discussed in Section IV below.

On the other hand, you also may choose to perform an initial examination to determine whether a particular BART-eligible source or group of sources causes or contributes to visibility impairment in nearby Class I areas. If your analysis, or information submitted by the source, shows that an individual source or group of sources (or certain pollutants from those sources) is not reasonably anticipated to cause or contribute to any visibility impairment in a Class I area, then you do not need to make BART determinations for that source or group of sources (or for certain pollutants from those sources). In such a case, the source is not "subject to BART" and you do not need to apply the five statutory factors to make a BART determination. This section of the Guideline discusses several approaches that you can use to exempt sources from the BART determination process.

A. What Steps Do I Follow To Determine Whether a Source or Group of Sources Cause or Contribute to Visibility Impairment for Purposes of BART?

1. How Do I Establish a Threshold?

One of the first steps in determining whether sources cause or contribute to visibility impairment for purposes of BART is to establish a threshold (measured in deciviews) against which to measure the visibility impact of one or more sources. A single source that is responsible for a 1.0 deciview change or more should be considered to "cause" visibility impairment; a source that causes less than a 1.0 deciview change may still contribute to visibility impairment and thus be subject to BART.

Because of varying circumstances affecting different Class I areas, the appropriate threshold for determining whether a source "contributes to any visibility impairment" for the purposes of BART may reasonably differ across States. As a general matter, any threshold that you use for determining whether a source "contributes" to visibility impairment should not be higher than 0.5 deciviews.

In setting a threshold for "contribution," you should consider the number of emissions sources affecting the Class I areas at issue and the magnitude of the individual sources' impacts.[5] In general, a larger number of sources causing impacts in a Class I area may warrant a lower contribution threshold. States remain free to use a threshold lower than 0.5 deciviews if they conclude that the

[3] We recognize that we are in a transition period from the use of the SIC system to a new system called the North American Industry Classification System (NAICS). For purposes of identifying BART-eligible sources, you may use either 2-digit SICS or the equivalent in the NAICS system.

[4] **Note:** The concept of support facility used for the NSR program applies here as well. Support facilities, that is facilities that convey, store or otherwise assist in the production of the principal product, must be grouped with primary facilities even when the facilities fall wihin separate SIC codes. For purposes of BART reviews, however, such support facilities (a) must be within one of the 26 listed source categories and (b) must have been in existence as of August 7, 1977, and (c) must not have been in operation as of August 7, 1962.

[5] We expect that regional planning organizations will have modeling information that identifies sources affecting visibility in individual class I areas.

location of a large number of BART-eligible sources within the State and in proximity to a Class I area justify this approach.[6]

2. What Pollutants Do I Need to Consider?

You must look at SO_2, NO_X, and direct particulate matter (PM) emissions in determining whether sources cause or contribute to visibility impairment, including both PM_{10} and $PM_{2.5}$. Consistent with the approach for identifying your BART-eligible sources, you do not need to consider less than de minimis emissions of these pollutants from a source.

As explained in section II, you must use your best judgement to determine whether VOC or ammonia emissions are likely to have an impact on visibility in an area. In addition, although as explained in Section II, you may use PM_{10} an indicator for particulate matter in determining whether a source is BART-eligible, in determining whether a source contributes to visibility impairment, you should distinguish between the fine and coarse particle components of direct particulate emissions. Although both fine and coarse particulate matter contribute to visibility impairment, the long-range transport of fine particles is of particular concern in the formation of regional haze. Air quality modeling results used in the BART determination will provide a more accurate prediction of a source's impact on visibility if the inputs into the model account for the relative particle size of any directly emitted particulate matter (i.e. PM_{10} vs. $PM_{2.5}$).

3. What Kind of Modeling Should I Use To Determine Which Sources and Pollutants Need Not Be Subject to BART?

This section presents several options for determining that certain sources need not be subject to BART. These options rely on different modeling and/or emissions analysis approaches. They are provided for your guidance. You may also use other reasonable approaches for analyzing the visibility impacts of an individual source or group of sources.

Option 1: Individual Source Attribution Approach (Dispersion Modeling)

You can use dispersion modeling to determine that an individual source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area and thus is not subject to BART. Under this option, you can analyze an individual source's impact on visibility as a result of its emissions of SO_2, NO_X and direct PM emissions. Dispersion modeling cannot currently be used to estimate the predicted impacts on visibility from an individual source's emissions of VOC or ammonia. You may use a more qualitative assessment to determine on a case-by-case basis which sources of VOC or ammonia emissions may be likely to impair visibility and should therefore be subject to BART review, as explained in section II.A.3. above.

You can use CALPUFF[7] or other appropriate model to predict the visibility impacts from a single source at a Class I area. CALPUFF is the best regulatory modeling application currently available for predicting a single source's contribution to visibility impairment and is currently the only EPA-approved model for use in estimating single source pollutant concentrations resulting from the long range transport of primary pollutants.[8] It can also be used for some other purposes, such as the visibility assessments addressed in today's rule, to account for the chemical transformation of SO_2 and NO_X.

There are several steps for making an individual source attribution using a dispersion model:

1. *Develop a modeling protocol.* Some critical items to include in the protocol are the meteorological and terrain data that will be used, as well as the source-specific information (stack height, temperature, exit velocity, elevation, and emission rates of applicable pollutants) and receptor data from appropriate Class I areas. We recommend following EPA's *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts*[9] for parameter settings and meteorological data inputs. You may use other settings from those in IWAQM, but you should identify these settings and explain your selection of these settings.

One important element of the protocol is in establishing the receptors that will be used in the model. The receptors that you use should be located in the nearest Class I area with sufficient density to identify the likely visibility effects of the source. For other Class I areas in relatively close proximity to a BART-eligible source, you may model a few strategic receptors to determine whether effects at those areas may be greater than at the nearest Class I area. For example, you might chose to locate receptors at these areas at the closest point to the source, at the highest and lowest elevation in the Class I area, at the IMPROVE monitor, and at the approximate expected plume release height. If the highest modeled effects are observed at the nearest Class I area, you may choose not to analyze the other Class I areas any further as additional analyses might be unwarranted.

You should bear in mind that some receptors within the relevant Class I area may be less than 50 km from the source while other receptors within that same Class I area may be greater than 50 km from the same source. As indicated by the Guideline on Air Quality Models, 40 CFR part 51, appendix W, this situation may call for the use of two different modeling approaches for the same Class I area and source, depending upon the State's chosen method for modeling sources less than 50 km. In situations where you are assessing visibility impacts for source-receptor distances less than 50 km, you should use expert modeling judgment in determining visibility impacts, giving consideration to both CALPUFF and other appropriate methods.

In developing your modeling protocol, you may want to consult with EPA and your regional planning organization (RPO). Up-front consultation will ensure that key technical issues are addressed before you conduct your modeling.

2. *With the accepted protocol and compare the predicted visibility impacts with your threshold for "contribution."* You should calculate daily visibility values for each receptor as the change in deciviews compared against natural visibility conditions. You can use EPA's "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule," EPA–454/B–03–005 (September 2003) in making this calculation. To determine whether a source may reasonably be anticipated to cause or contribute to visibility impairment at Class I area, you then compare the impacts predicted by the model against the threshold that you have selected.

The emissions estimates used in the models are intended to reflect steady-state operating conditions during periods of high capacity utilization. We do not generally recommend that emissions reflecting periods of start-up, shutdown, and malfunction be used, as such emission rates could produce higher than normal effects than would be typical of most facilities. We recommend that States use the 24 hour average actual emission rate from the highest emitting day of the meteorological period modeled, unless this rate reflects periods start-up, shutdown, or malfunction. In addition, the monthly average relative humidity is used, rather than the daily average humidity—an approach that effectively lowers the peak values in daily model averages.

For these reasons, if you use the modeling approach we recommend, you should compare your "contribution" threshold against the 98th percentile of values. If the 98th percentile value from your modeling is less than your contribution threshold, then you may conclude that the source does not contribute to visibility impairment and is not subject to BART.

Option 2: Use of Model Plants To Exempt Individual Sources With Common Characteristics

Under this option, analyses of model plants could be used to exempt certain BART-eligible sources that share specific characteristics. It may be most useful to use this type of analysis to identify the types of small sources that do not cause or contribute to visibility impairment for purposes of BART, and thus should not be subject to a BART review. Different Class I areas may have different characteristics, however, so

[6] Note that the contribution threshold should be used to determine whether an individual source is reasonably anticipated to contribute to visibility impairment. You should not aggregate the visibility effects of multiple sources and compare their collective effects against your contribution threshold because this would inappropriately create a "contribute to contribution" test.

[7] The model code and its documentation are available at no cost for download from *http://www.epa.gov/scram001/tt22.htm#calpuff.*

[8] The Guideline on Air Quality Models, 40 CFR part 51, appendix W, addresses the regulatory application of air quality models for assessing criteria pollutants under the CAA, and describes further the procedures for using the CALPUFF model, as well as for obtaining approval for the use of other, nonguideline models.

[9] *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts,* U.S. Environmental Protection Agency, EPA–454/R–98–019, December 1998.

you should use care to ensure that the criteria you develop are appropriate for the applicable cases.

In carrying out this approach, you could use modeling analyses of representative plants to reflect groupings of specific sources with important common characteristics. Based on these analyses, you may find that certain types of sources are clearly anticipated to cause or contribute to visibility impairment. You could then choose to categorically require those types of sources to undergo a BART determination. Conversely, you may find based on representative plant analyses that certain types of sources are not reasonably anticipated to cause or contribute to visibility impairment. To do this, you may conduct your own modeling to establish emission levels and distances from Class I areas on which you can rely to exempt sources with those characteristics. For example, based on your modeling you might choose to exempt all NO_X-only sources that emit less than a certain amount per year and are located a certain distance from a Class I area. You could then choose to categorically exempt such sources from the BART determination process.

Our analyses of visibility impacts from model plants provide a useful example of the type of analyses that can be used to exempt categories of sources from BART.[10] In our analyses, we developed model plants (EGUs and non-EGUs), with representative plume and stack characteristics, for use in considering the visibility impact from emission sources of different sizes and compositions at distances of 50, 100 and 200 kilometers from two hypothetical Class I areas (one in the East and one in the West). As the plume and stack characteristics of these model plants were developed considering the broad range of sources within the EGU and non-EGU categories, they do not necessarily represent any specific plant. However, the results of these analyses are instructive in the development of an exemption process for any Class I area.

In preparing our analyses, we have made a number of assumptions and exercised certain modeling choices; some of these have a tendency to lend conservatism to the results, overstating the likely effects, while others may understate the likely effects. On balance, when all of these factors are considered, we believe that our examples reflect realistic treatments of the situations being modeled. Based on our analyses, we believe that a State that has established 0.5 deciviews as a contribution threshold could reasonably exempt from the BART review process sources that emit less than 500 tons per year of NO_X or SO_2 (or combined NO_X and SO_2), as long as these sources are located more than 50 kilometers from any Class I area; and sources that emit less than 1000 tons per year of NO_X or SO_2 (or combined NO_X and SO_2) that are located more than 100 kilometers from any Class I area. You do, however, have the option of showing other thresholds might also be appropriate given your specific circumstances.

[10] CALPUFF Analysis in Support of the June 2005 Changes to the Regional Haze Rule, U.S. Environmental Protection Agency, June 15, 2005, Docket No. OAR–2002–0076.

Option 3: Cumulative Modeling To Show That No Sources in a State Are Subject to BART

You may also submit to EPA a demonstration based on an analysis of overall visibility impacts that emissions from BART-eligible sources in your State, considered together, are not reasonably anticipated to cause or contribute to any visibility impairment in a Class I area, and thus no source should be subject to BART. You may do this on a pollutant by pollutant basis or for all visibility-impairing pollutants to determine if emissions from these sources contribute to visibility impairment.

For example, emissions of SO_2 from your BART-eligible sources may clearly cause or contribute to visibility impairment while direct emissions of $PM_{2.5}$ from these sources may not contribute to impairment. If you can make such a demonstration, then you may reasonably conclude that none of your BART-eligible sources are subject to BART for a particular pollutant or pollutants. As noted above, your demonstration should take into account the interactions among pollutants and their resulting impacts on visibility before making any pollutant-specific determinations.

Analyses may be conducted using several alternative modeling approaches. First, you may use the CALPUFF or other appropriate model as described in Option 1 to evaluate the impacts of individual sources on downwind Class I areas, aggregating those impacts to determine the collective contribution of all BART-eligible sources to visibility impairment. You may also use a photochemical grid model. As a general matter, the larger the number of sources being modeled, the more appropriate it may be to use a photochemical grid model. However, because such models are significantly less sensitive than dispersion models to the contributions of one or a few sources, as well as to the interactions among sources that are widely distributed geographically, if you wish to use a grid model, you should consult with the appropriate EPA Regional Office to develop an appropriate modeling protocol.

IV. The BART Determination: Analysis of BART Options

This section describes the process for the analysis of control options for sources subject to BART.

A. What factors must I address in the BART review?

The visibility regulations define BART as follows:

Best Available Retrofit Technology (BART) means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by . . . [a BART-eligible source]. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

The BART analysis identifies the best system of continuous emission reduction taking into account:

(1) The available retrofit control options,

(2) Any pollution control equipment in use at the source (which affects the availability of options and their impacts),

(3) The costs of compliance with control options,

(4) The remaining useful life of the facility,

(5) The energy and non-air quality environmental impacts of control options

(6) The visibility impacts analysis.

B. What is the scope of the BART review?

Once you determine that a source is subject to BART for a particular pollutant, then for each affected emission unit, you must establish BART for that pollutant. The BART determination must address air pollution control measures for each emissions unit or pollutant emitting activity subject to review.

Example: Plantwide emissions from emission units within the listed categories that began operation within the "time window" for BART[11] are 300 tons/yr of NO_X, 200 tons/yr of SO_2, and 150 tons/yr of primary particulate. Emissions unit A emits 200 tons/yr of NO_X, 100 tons/yr of SO_2, and 100 tons/yr of primary particulate. Other emission units, units B through H, which began operating in 1966, contribute lesser amounts of each pollutant. For this example, a BART review is required for NO_X, SO_2, and primary particulate, and control options must be analyzed for units B through H as well as unit A.

C. How does a BART review relate to Maximum Achievable Control Technology (MACT) Standards under CAA section 112, or to other emission limitations required under the CAA?

For VOC and PM sources subject to MACT standards, States may streamline the analysis by including a discussion of the MACT controls and whether any major new technologies have been developed subsequent to the MACT standards. We believe that there are many VOC and PM sources that are well controlled because they are regulated by the MACT standards, which EPA developed under CAA section 112. For a few MACT standards, this may also be true for SO_2. Any source subject to MACT standards must meet a level that is as stringent as the best-controlled 12 percent of sources in the industry. Examples of these hazardous air pollutant sources which effectively control VOC and PM emissions include (among others) secondary lead facilities, organic chemical plants subject to the hazardous organic NESHAP (HON), pharmaceutical production facilities, and equipment leaks and wastewater operations at petroleum refineries. We believe that, in many cases, it will be unlikely that States will identify emission controls more stringent than the MACT standards without

[11] That is, emission units that were in existence on August 7, 1977 and which began actual operation on or after August 7, 1962.

identifying control options that would cost many thousands of dollars per ton. Unless there are new technologies subsequent to the MACT standards which would lead to cost-effective increases in the level of control, you may rely on the MACT standards for purposes of BART.

We believe that the same rationale also holds true for emissions standards developed for municipal waste incinerators under CAA section 111(d), and for many NSR/PSD determinations and NSR/PSD settlement agreements. However, we do not believe that technology determinations from the 1970s or early 1980s, including new source performance standards (NSPS), should be considered to represent best control for existing sources, as best control levels for recent plant retrofits are more stringent than these older levels.

Where you are relying on these standards to represent a BART level of control, you should provide the public with a discussion of whether any new technologies have subsequently become available.

D. What Are the Five Basic Steps of a Case-by-Case BART Analysis?

The five steps are:

STEP 1—Identify All[12] Available Retrofit Control Technologies,

STEP 2— Eliminate Technically Infeasible Options,

STEP 3— Evaluate Control Effectiveness of Remaining Control Technologies,

STEP 4— Evaluate Impacts and Document the Results, and

STEP 5—Evaluate Visibility Impacts.

1. STEP 1: How do I identify all available retrofit emission control techniques?

1. Available retrofit control options are those air pollution control technologies with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies can include a wide variety of available methods, systems, and techniques for control of the affected pollutant. Technologies required as BACT or LAER are available for BART purposes and must be included as control alternatives. The control alternatives can include not only existing controls for the source category in question but also take into account technology transfer of controls that have been applied to similar source categories and gas streams. Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered as available; we do not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice.

2. Where a NSPS exists for a source category (which is the case for most of the categories affected by BART), you should include a level of control equivalent to the NSPS as one of the control options.[13] The NSPS standards are codified in 40 CFR part 60. We note that there are situations where NSPS standards do not require the most stringent level of available control for all sources within a category. For example, post-combustion NO_X controls (the most stringent controls for stationary gas turbines) are not required under subpart GG of the NSPS for Stationary Gas Turbines. However, such controls must still be considered available technologies for the BART selection process.

3. Potentially applicable retrofit control alternatives can be categorized in three ways.

- Pollution prevention: use of inherently lower-emitting processes/practices, including the use of control techniques (*e.g.* low-NO_X burners) and work practices that prevent emissions and result in lower "production-specific" emissions (note that it is not our intent to direct States to switch fuel forms, *e.g.* from coal to gas),
- Use of (and where already in place, improvement in the performance of) add-on controls, such as scrubbers, fabric filters, thermal oxidizers and other devices that control and reduce emissions after they are produced, and
- Combinations of inherently lower-emitting processes and add-on controls.

4. In the course of the BART review, one or more of the available control options may be eliminated from consideration because they are demonstrated to be technically infeasible or to have unacceptable energy, cost, or non-air quality environmental impacts on a case-by-case (or site-specific) basis. However, at the outset, you should initially identify all control options with potential application to the emissions unit under review.

5. We do not consider BART as a requirement to redesign the source when considering available control alternatives. For example, where the source subject to BART is a coal-fired electric generator, we do not require the BART analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting on a per unit basis.

6. For emission units subject to a BART review, there will often be control measures or devices already in place. For such emission units, it is important to include control options that involve improvements to existing controls and not to limit the control options only to those measures that involve a complete replacement of control devices.

Example: For a power plant with an existing wet scrubber, the current control efficiency is 66 percent. Part of the reason for the relatively low control efficiency is that 22 percent of the gas stream bypasses the scrubber. A BART review identifies options for improving the performance of the wet scrubber by redesigning the internal components of the scrubber and by eliminating or reducing the percentage of the gas stream that bypasses the scrubber. Four control options are identified: (1) 78 percent control based upon improved scrubber performance while maintaining the 22 percent bypass, (2) 83 percent control based upon improved scrubber performance while reducing the bypass to 15 percent, (3) 93 percent control based upon improving the scrubber performance while eliminating the bypass entirely, (this option results in a "wet stack" operation in which the gas leaving the stack is saturated with water) and (4) 93 percent as in option 3, with the addition of an indirect reheat system to reheat the stack gas above the saturation temperature. You must consider each of these four options in a BART analysis for this source.

7. You are expected to identify potentially applicable retrofit control technologies that represent the full range of demonstrated alternatives. Examples of general information sources to consider include:

- The EPA's Clean Air Technology Center, which includes the RACT/BACT/LAER Clearinghouse (RBLC);
- State and Local Best Available Control Technology Guidelines—many agencies have online information—for example South Coast Air Quality Management District, Bay Area Air Quality Management District, and Texas Natural Resources Conservation Commission;
- Control technology vendors;
- Federal/State/Local NSR permits and associated inspection/performance test reports;
- Environmental consultants;
- Technical journals, reports and newsletters, air pollution control seminars; and
- The EPA's NSR bulletin board—*http://www.epa.gov/ttn/nsr;*
- Department of Energy's Clean Coal Program—technical reports;
- The NO_X Control Technology "Cost Tool"—Clean Air Markets Division Web page—*http://www.epa.gov/airmarkets/arp/nox/controltech.html;*
- Performance of selective catalytic reduction on coal-fired steam generating units—final report. OAR/ARD, June 1997 (also available at *http://www.epa.gov/airmarkets/arp/nox/controltech.html*);
- Cost estimates for selected applications of NO_X control technologies on stationary combustion boilers. OAR/ARD June 1997. (Docket for NO_X SIP Call, A–96–56, item II–A–03);
- Investigation of performance and cost of NO_X controls as applied to group 2 boilers. OAR/ARD, August 1996. (Docket for Phase II NO_X rule, A–95–28, item IV–A–4);
- Controlling SO_2 Emissions: A Review of Technologies. EPA–600/R–00–093, USEPA/ORD/NRMRL, October 2000; and
- The OAQPS Control Cost Manual.

You are expected to compile appropriate information from these information sources.

8. There may be situations where a specific set of units within a fenceline constitutes the

[12] In identifying "all" options, you must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. It is not necessary to list all permutations of available control levels that exist for a given technology—the list is complete if it includes the maximum level of control each technology is capable of achieving.

[13] In EPA's 1980 BART guidelines for reasonably attributable visibility impairment, we concluded that NSPS standards generally, at that time, represented the best level sources could install as BART. In the 20 year period since this guidance was developed, there have been advances in SO_2 control technologies as well as technologies for the control of other pollutants, confirmed by a number of recent retrofits at Western power plants. Accordingly, EPA no longer concludes that the NSPS level of controls automatically represents "the best these sources can install." Analysis of the BART factors could result in the selection of a NSPS level of control, but you should reach this conclusion only after considering the full range of control options.

logical set to which controls would apply and that set of units may or may not all be BART-eligible. (For example, some units in that set may not have been constructed between 1962 and 1977.)

9. If you find that a BART source has controls already in place which are the most stringent controls available (note that this means that all possible improvements to any control devices have been made), then it is not necessary to comprehensively complete each following step of the BART analysis in this section. As long these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source, you may skip the remaining analyses in this section, including the visibility analysis in step 5. Likewise, if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses in this section.

2. STEP 2: *How do I determine whether the options identified in Step 1 are technically feasible?*

In Step 2, you evaluate the technical feasibility of the control options you identified in Step 1. You should document a demonstration of technical infeasibility and should explain, based on physical, chemical, or engineering principles, why technical difficulties would preclude the successful use of the control option on the emissions unit under review. You may then eliminate such technically infeasible control options from further consideration in the BART analysis.

In general, what do we mean by technical feasibility?

Control technologies are technically feasible if either (1) they have been installed and operated successfully for the type of source under review under similar conditions, or (2) the technology could be applied to the source under review. Two key concepts are important in determining whether a technology could be applied: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

What do we mean by "available" technology?

1. The typical stages for bringing a control technology concept to reality as a commercial product are:

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

2. A control technique is considered available, within the context presented above, if it has reached the stage of licensing and commercial availability. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as "available" for purposes of BART review.

3. Commercial availability by itself, however, is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to the source type under consideration.

Because a new technology may become available at various points in time during the BART analysis process, we believe that guidelines are needed on when a technology must be considered. For example, a technology may become available during the public comment period on the State's rule development process. Likewise, it is possible that new technologies may become available after the close of the State's public comment period and before submittal of the SIP to EPA, or during EPA's review process on the SIP submittal. In order to provide certainty in the process, all technologies should be considered if available before the close of the State's public comment period. You need not consider technologies that become available after this date. As part of your analysis, you should consider any technologies brought to your attention in public comments. If you disagree with public comments asserting that the technology is available, you should provide an explanation for the public record as to the basis for your conclusion.

What do we mean by "applicable" technology?

You need to exercise technical judgment in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been used on the same or a similar source type. Absent a showing of this type, you evaluate technical feasibility by examining the physical and chemical characteristics of the pollutant-bearing gas stream, and comparing them to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on a new or existing source with similar gas stream characteristics is generally a sufficient basis for concluding the technology is technically feasible barring a demonstration to the contrary as described below.

What type of demonstration is required if I conclude that an option is not technically feasible?

1. Where you conclude that a control option identified in Step 1 is technically infeasible, you should demonstrate that the option is either commercially unavailable, or that specific circumstances preclude its application to a particular emission unit. Generally, such a demonstration involves an evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology. Alternatively, a demonstration of technical infeasibility may involve a showing that there are unresolvable technical difficulties with applying the control to the source (*e.g.*, size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space constraints, reliability, and adverse side effects on the rest of the facility). Where the resolution of technical difficulties is merely a matter of increased cost, you should consider the technology to be technically feasible. The cost of a control alternative is considered later in the process.

2. The determination of technical feasibility is sometimes influenced by recent air quality permits. In some cases, an air quality permit may require a certain level of control, but the level of control in a permit is not expected to be achieved in practice (*e.g.*, a source has received a permit but the project was canceled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit). Where this is the case, you should provide supporting documentation showing why such limits are not technically feasible, and, therefore, why the level of control (but not necessarily the technology) may be eliminated from further consideration. However, if there is a permit requiring the application of a certain technology or emission limit to be achieved for such technology, this usually is sufficient justification for you to assume the technical feasibility of that technology or emission limit.

3. Physical modifications needed to resolve technical obstacles do not, in and of themselves, provide a justification for eliminating the control technique on the basis of technical infeasibility. However, you may consider the cost of such modifications in estimating costs. This, in turn, may form the basis for eliminating a control technology (see later discussion).

4. Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances. However, we do not consider a vendor guarantee alone to be sufficient justification that a control option will work. Conversely, lack of a vendor guarantee by itself does not present sufficient justification that a control option or an emissions limit is technically infeasible. Generally, you should make decisions about technical feasibility based on chemical, and engineering analyses (as discussed above), in conjunction with information about vendor guarantees.

5. A possible outcome of the BART procedures discussed in these guidelines is the evaluation of multiple control technology alternatives which result in essentially equivalent emissions. It is not our intent to encourage evaluation of unnecessarily large numbers of control alternatives for every emissions unit. Consequently, you should use judgment in deciding on those alternatives for which you will conduct the detailed impacts analysis (Step 4 below). For example, if two or more control techniques result in control levels that are essentially identical, considering the uncertainties of emissions factors and other parameters

pertinent to estimating performance, you may evaluate only the less costly of these options. You should narrow the scope of the BART analysis in this way only if there is a negligible difference in emissions and energy and non-air quality environmental impacts between control alternatives.

3. STEP 3: How do I evaluate technically feasible alternatives?

Step 3 involves evaluating the control effectiveness of all the technically feasible control alternatives identified in Step 2 for the pollutant and emissions unit under review.

Two key issues in this process include:

(1) Making sure that you express the degree of control using a metric that ensures an "apples to apples" comparison of emissions performance levels among options, and

(2) Giving appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels.

What are the appropriate metrics for comparison?

This issue is especially important when you compare inherently lower-polluting processes to one another or to add-on controls. In such cases, it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed.

Examples of common metrics:

- Pounds of SO_2 emissions per million Btu heat input, and
- Pounds of NO_X emissions per ton of cement produced.

How do I evaluate control techniques with a wide range of emission performance levels?

1. Many control techniques, including both add-on controls and inherently lower polluting processes, can perform at a wide range of levels. Scrubbers and high and low efficiency electrostatic precipitators (ESPs) are two of the many examples of such control techniques that can perform at a wide range of levels. It is not our intent to require analysis of each possible level of efficiency for a control technique as such an analysis would result in a large number of options. It is important, however, that in analyzing the technology you take into account the most stringent emission control level that the technology is capable of achieving. You should consider recent regulatory decisions and performance data (*e.g.*, manufacturer's data, engineering estimates and the experience of other sources) when identifying an emissions performance level or levels to evaluate.

2. In assessing the capability of the control alternative, latitude exists to consider special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative. However, you should explain the basis for choosing the alternate level (or range) of control in the BART analysis. Without a showing of differences between the source and other sources that have achieved more stringent emissions limits, you should conclude that the level being achieved by those other sources is representative of the achievable level for the source being analyzed.

3. You may encounter cases where you may wish to evaluate other levels of control in addition to the most stringent level for a given device. While you must consider the most stringent level as one of the control options, you may consider less stringent levels of control as additional options. This would be useful, particularly in cases where the selection of additional options would have widely varying costs and other impacts.

4. Finally, we note that for retrofitting existing sources in addressing BART, you should consider ways to improve the performance of existing control devices, particularly when a control device is not achieving the level of control that other similar sources are achieving in practice with the same device. For example, you should consider requiring those sources with electrostatic precipitators (ESPs) performing below currently achievable levels to improve their performance.

4. STEP 4: For a BART review, what impacts am I expected to calculate and report? What methods does EPA recommend for the impacts analysis?

After you identify the available and technically feasible control technology options, you are expected to conduct the following analyses when you make a BART determination:

Impact analysis part 1: Costs of compliance,

Impact analysis part 2: Energy impacts, and

Impact analysis part 3: Non-air quality environmental impacts.

Impact analysis part 4: Remaining useful life.

In this section, we describe how to conduct each of these three analyses. You are responsible for presenting an evaluation of each impact along with appropriate supporting information. You should discuss and, where possible, quantify both beneficial and adverse impacts. In general, the analysis should focus on the direct impact of the control alternative.

a. Impact analysis part 1: how do I estimate the costs of control?

1. To conduct a cost analysis, you:

(1) Identify the emissions units being controlled,

(2) Identify design parameters for emission controls, and

(3) Develop cost estimates based upon those design parameters.

2. It is important to identify clearly the emission units being controlled, that is, to specify a well-defined area or process segment within the plant. In some cases, multiple emission units can be controlled jointly. However, in other cases, it may be appropriate in the cost analysis to consider whether multiple units will be required to install separate and/or different control devices. The analysis should provide a clear summary list of equipment and the associated control costs. Inadequate documentation of the equipment whose emissions are being controlled is a potential cause for confusion in comparison of costs of the same controls applied to similar sources.

3. You then specify the control system design parameters. Potential sources of these design parameters include equipment vendors, background information documents used to support NSPS development, control technique guidelines documents, cost manuals developed by EPA, control data in trade publications, and engineering and performance test data. The following are a few examples of design parameters for two example control measures:

Control device	Examples of design parameters
Wet Scrubbers ..	Type of sorbent used (lime, limestone, etc.). Gas pressure drop. Liquid/gas ratio.
Selective Catalytic Reduction.	Ammonia to NO_X molar ratio. Pressure drop. Catalyst life.

4. The value selected for the design parameter should ensure that the control option will achieve the level of emission control being evaluated. You should include in your analysis documentation of your assumptions regarding design parameters. Examples of supporting references would include the EPA OAQPS *Control Cost Manual* (see below) and background information documents used for NSPS and hazardous pollutant emission standards. If the design parameters you specified differ from typical designs, you should document the difference by supplying performance test data for the control technology in question applied to the same source or a similar source.

5. Once the control technology alternatives and achievable emissions performance levels have been identified, you then develop estimates of capital and annual costs. The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (*i.e.*, budget estimates or bids) or by a referenced source (such as the *OAQPS Control Cost Manual*, Fifth Edition, February 1996, EPA 453/B–96–001).[14] In order to maintain and improve consistency, cost estimates should be based on the *OAQPS Control Cost Manual*, where possible.[15] The *Control Cost Manual* addresses most control technologies in sufficient detail for a BART analysis. The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option.

[14] The *OAQPS Control Cost Manual* is updated periodically. While this citation refers to the latest version at the time this guidance was written, you should use the version that is current as of when you conduct your impact analysis. This document is available at the following Web site: *http://www.epa.gov/ttn/catc/dir1/cs1ch2.pdf.*

[15] You should include documentation for any additional information you used for the cost calculations, including any information supplied by vendors that affects your assumptions regarding purchased equipment costs, equipment life, replacement of major components, and any other element of the calculation that differs from the *Control Cost Manual.*

b. What do we mean by cost effectiveness?

Cost effectiveness, in general, is a criterion used to assess the potential for achieving an objective in the most economical way. For purposes of air pollutant analysis, "effectiveness" is measured in terms of tons of pollutant emissions removed, and "cost" is measured in terms of annualized control costs. We recommend two types of cost-effectiveness calculations—average cost effectiveness, and incremental cost effectiveness.

c. How do I calculate average cost effectiveness?

Average cost effectiveness means the total annualized costs of control divided by annual emissions reductions (the difference between baseline annual emissions and the estimate of emissions after controls), using the following formula:

Average cost effectiveness (dollars per ton removed) = *Control option annualized cost*[16]

Baseline annual emissions—Annual emissions with Control option

Because you calculate costs in (annualized) dollars per year ($/yr) and because you calculate emissions rates in tons per year (tons/yr), the result is an average cost-effectiveness number in (annualized) dollars per ton ($/ton) of pollutant removed.

d. How do I calculate baseline emissions?

1. The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period.

2. When you project that future operating parameters (*e.g.*, limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.

3. For example, the baseline emissions calculation for an emergency standby generator may consider the fact that the source owner would not operate more than past practice of 2 weeks a year. On the other hand, baseline emissions associated with a base-loaded turbine should be based on its past practice which would indicate a large number of hours of operation. This produces a significantly higher level of baseline emissions than in the case of the emergency/standby unit and results in more cost-effective controls. As a consequence of the dissimilar baseline emissions, BART for the two cases could be very different.

e. How do I calculate incremental cost effectiveness?

1. In addition to the average cost effectiveness of a control option, you should also calculate incremental cost effectiveness. You should consider the incremental cost effectiveness in combination with the average cost effectiveness when considering whether to eliminate a control option. The incremental cost effectiveness calculation compares the costs and performance level of a control option to those of the next most stringent option, as shown in the following formula (with respect to cost per emissions reduction):

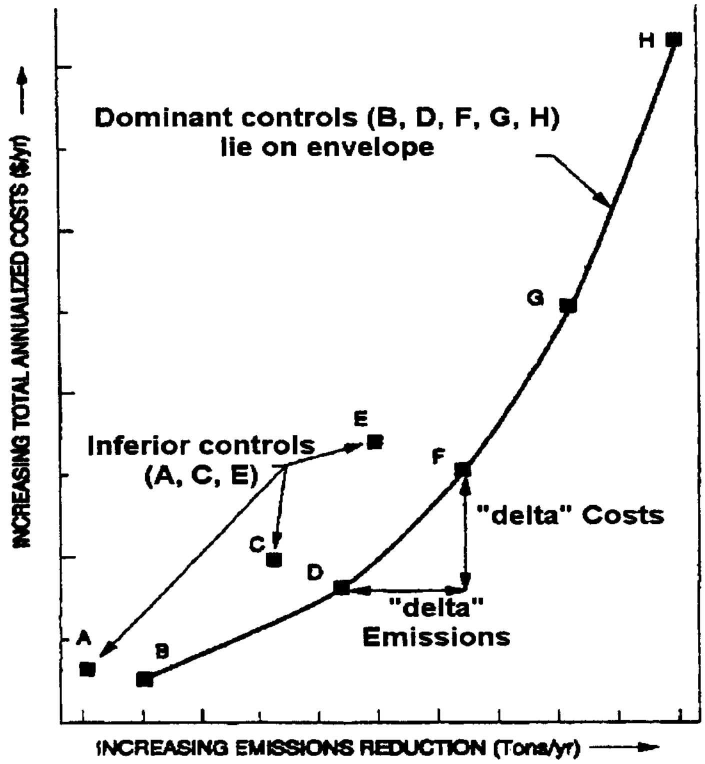
Incremental Cost Effectiveness (dollars per incremental ton removed) = (Total annualized costs of control option) − (Total annualized costs of next control option) ÷ (Control option annual emissions) − (Next control option annual emissions)

Example 1: Assume that Option F on Figure 2 has total annualized costs of $1 million to reduce 2000 tons of a pollutant, and that Option D on Figure 2 has total annualized costs of $500,000 to reduce 1000 tons of the same pollutant. The incremental cost effectiveness of Option F relative to Option D is ($1 million − $500,000) divided by (2000 tons − 1000 tons), or $500,000 divided by 1000 tons, which is $500/ton.

Example 2: Assume that two control options exist: Option 1 and Option 2. Option 1 achieves a 1,000 ton/yr reduction at an annualized cost of $1,900,000. This represents an average cost of ($1,900,000/1,000 tons) = $1,900/ton. Option 2 achieves a 980 tons/yr reduction at an annualized cost of $1,500,000. This represents an average cost of ($1,500,000/980 tons) = $1,531/ton. The incremental cost effectiveness of Option 1 relative to Option 2 is ($1,900,000 − $1,500,000) divided by (1,000 tons − 980 tons). The adoption of Option 1 instead of Option 2 results in an incremental emission reduction of 20 tons per year at an additional cost of $400,000 per year. The incremental cost of Option 1, then, is $20,000 per ton − 11 times the average cost of $1,900 per ton. While $1,900 per ton may still be deemed reasonable, it is useful to consider both the average and incremental cost in making an overall cost-effectiveness finding. Of course, there may be other differences between these options, such as, energy or water use, or non-air environmental effects, which also should be considered in selecting a BART technology.

2. You should exercise care in deriving incremental costs of candidate control options. Incremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between "dominant" alternatives. To identify dominant alternatives, you generate a graphical plot of total annualized costs for total emissions reductions for all control alternatives identified in the BART analysis, and by identifying a "least-cost envelope" as shown in Figure 2. (A "least-cost envelope" represents the set of options that should be dominant in the choice of a specific option.)

[16] Whenever you calculate or report annual costs, you should indicate the year for which the costs are estimated. For example, if you use the year 2000 as the basis for cost comparisons, you would report that an annualized cost of $20 million would be: $20 million (year 2000 dollars).



Example: Eight technically feasible control options for analysis are listed. These are represented as A through H in Figure 2. The dominant set of control options, B, D, F, G, and H, represent the least-cost envelope, as we depict by the cost curve connecting them. Points A, C and E are inferior options, and you should not use them in calculating incremental cost effectiveness. Points A, C and E represent inferior controls because B will buy more emissions reductions for less money than A; and similarly, D and F will buy more reductions for less money than C and E, respectively.

3. In calculating incremental costs, you:

(1) Array the control options in ascending order of annualized total costs,

(2) Develop a graph of the most reasonable smooth curve of the control options, as shown in Figure 2. This is to show the "least-cost envelope" discussed above; and

(3) Calculate the incremental cost effectiveness for each dominant option, which is the difference in total annual costs between that option and the next most stringent option, divided by the difference in emissions, after controls have been applied, between those two control options. For example, using Figure 2, you would calculate incremental cost effectiveness for the difference between options B and D, options D and F, options F and G, and options G and H.

4. A comparison of incremental costs can also be useful in evaluating the viability of a specific control option over a range of efficiencies. For example, depending on the capital and operational cost of a control device, total and incremental cost may vary significantly (either increasing or decreasing) over the operational range of a control device. Also, the greater the number of possible control options that exist, the more weight should be given to the incremental costs vs. average costs. It should be noted that average and incremental cost effectiveness are identical when only one candidate control option is known to exist.

5. You should exercise caution not to misuse these techniques. For example, you may be faced with a choice between two available control devices at a source, control A and control B, where control B achieves slightly greater emission reductions. The average cost (total annual cost/total annual emission reductions) for each may be deemed to be reasonable. However, the incremental cost (total annual cost$_{A-B}$/total annual emission reductions$_{A-B}$) of the additional emission reductions to be achieved by control B may be very great. In such an instance, it may be inappropriate to choose control B, based on its high incremental costs, even though its average cost may be considered reasonable.

6. In addition, when you evaluate the average or incremental cost effectiveness of a control alternative, you should make reasonable and supportable assumptions regarding control efficiencies. An unrealistically low assessment of the emission reduction potential of a certain technology could result in inflated cost-effectiveness figures.

f. What other information should I provide in the cost impacts analysis?

You should provide documentation of any unusual circumstances that exist for the source that would lead to cost-effectiveness estimates that would exceed that for recent retrofits. This is especially important in cases where recent retrofits have cost-effectiveness values that are within what has been considered a reasonable range, but your analysis concludes that costs for the source being analyzed are not considered reasonable. (A reasonable range would be a range that is consistent with the range of cost effectiveness values used in other similar permit decisions over a period of time.)

Example: In an arid region, large amounts of water are needed for a scrubbing system. Acquiring water from a distant location could greatly increase the cost per ton of emissions reduced of wet scrubbing as a control option.

g. What other things are important to consider in the cost impacts analysis?

In the cost analysis, you should take care not to focus on incomplete results or partial calculations. For example, large capital costs for a control option alone would not preclude selection of a control measure if large emissions reductions are projected. In such a case, low or reasonable cost effectiveness numbers may validate the option as an appropriate BART alternative irrespective of the large capital costs. Similarly, projects with relatively low capital costs may not be cost effective if there are few emissions reduced.

h. Impact analysis part 2: How should I analyze and report energy impacts?

1. You should examine the energy requirements of the control technology and determine whether the use of that technology results in energy penalties or benefits. A source owner may, for example, benefit from the combustion of a concentrated gas stream rich in volatile organic compounds; on the other hand, more often extra fuel or electricity is required to power a control

device or incinerate a dilute gas stream. If such benefits or penalties exist, they should be quantified to the extent practicable. Because energy penalties or benefits can usually be quantified in terms of additional cost or income to the source, the energy impacts analysis can, in most cases, simply be factored into the cost impacts analysis. The fact of energy use in and of itself does not disqualify a technology.

2. Your energy impact analysis should consider only direct energy consumption and not indirect energy impacts. For example, you could estimate the direct energy impacts of the control alternative in units of energy consumption at the source (*e.g.*, BTU, kWh, barrels of oil, tons of coal). The energy requirements of the control options should be shown in terms of total (and in certain cases, also incremental) energy costs per ton of pollutant removed. You can then convert these units into dollar costs and, where appropriate, factor these costs into the control cost analysis.

3. You generally do not consider indirect energy impacts (such as energy to produce raw materials for construction of control equipment). However, if you determine, either independently or based on a showing by the source owner, that the indirect energy impact is unusual or significant and that the impact can be well quantified, you may consider the indirect impact.

4. The energy impact analysis may also address concerns over the use of locally scarce fuels. The designation of a scarce fuel may vary from region to region. However, in general, a scarce fuel is one which is in short supply locally and can be better used for alternative purposes, or one which may not be reasonably available to the source either at the present time or in the near future.

5. Finally, the energy impacts analysis may consider whether there are relative differences between alternatives regarding the use of locally or regionally available coal, and whether a given alternative would result in significant economic disruption or unemployment. For example, where two options are equally cost effective and achieve equivalent or similar emissions reductions, one option may be preferred if the other alternative results in significant disruption or unemployment.

i. Impact analysis part 3: How do I analyze "non-air quality environmental impacts?"

1. In the non-air quality related environmental impacts portion of the BART analysis, you address environmental impacts other than air quality due to emissions of the pollutant in question. Such environmental impacts include solid or hazardous waste generation and discharges of polluted water from a control device.

2. You should identify any significant or unusual environmental impacts associated with a control alternative that have the potential to affect the selection or elimination of a control alternative. Some control technologies may have potentially significant secondary environmental impacts. Scrubber effluent, for example, may affect water quality and land use. Alternatively, water availability may affect the feasibility and costs of wet scrubbers. Other examples of secondary environmental impacts could include hazardous waste discharges, such as spent catalysts or contaminated carbon. Generally, these types of environmental concerns become important when sensitive site-specific receptors exist or when the incremental emissions reductions potential of the more stringent control is only marginally greater than the next most-effective option. However, the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BART, particularly if the control device has been applied to similar facilities elsewhere and the solid or liquid waste is similar to those other applications. On the other hand, where you or the source owner can show that unusual circumstances at the proposed facility create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control alternative as BART.

3. The procedure for conducting an analysis of non-air quality environmental impacts should be made based on a consideration of site-specific circumstances. If you propose to adopt the most stringent alternative, then it is not necessary to perform this analysis of environmental impacts for the entire list of technologies you ranked in Step 3. In general, the analysis need only address those control alternatives with any significant or unusual environmental impacts that have the potential to affect the selection of a control alternative, or elimination of a more stringent control alternative. Thus, any important relative environmental impacts (both positive and negative) of alternatives can be compared with each other.

4. In general, the analysis of impacts starts with the identification and quantification of the solid, liquid, and gaseous discharges from the control device or devices under review. Initially, you should perform a qualitative or semi-quantitative screening to narrow the analysis to discharges with potential for causing adverse environmental effects. Next, you should assess the mass and composition of any such discharges and quantify them to the extent possible, based on readily available information. You should also assemble pertinent information about the public or environmental consequences of releasing these materials.

j. Impact analysis part 4: What are examples of non-air quality environmental impacts?

The following are examples of how to conduct non-air quality environmental impacts:

(1) *Water Impact*

You should identify the relative quantities of water used and water pollutants produced and discharged as a result of the use of each alternative emission control system. Where possible, you should assess the effect on ground water and such local surface water quality parameters as ph, turbidity, dissolved oxygen, salinity, toxic chemical levels, temperature, and any other important considerations. The analysis could consider whether applicable water quality standards will be met and the availability and effectiveness of various techniques to reduce potential adverse effects.

(2) *Solid Waste Disposal Impact*

You could also compare the quality and quantity of solid waste (*e.g.*, sludges, solids) that must be stored and disposed of or recycled as a result of the application of each alternative emission control system. You should consider the composition and various other characteristics of the solid waste (such as permeability, water retention, rewatering of dried material, compression strength, leachability of dissolved ions, bulk density, ability to support vegetation growth and hazardous characteristics) which are significant with regard to potential surface water pollution or transport into and contamination of subsurface waters or aquifers.

(3) *Irreversible or Irretrievable Commitment of Resources*

You may consider the extent to which the alternative emission control systems may involve a trade-off between short-term environmental gains at the expense of long-term environmental losses and the extent to which the alternative systems may result in irreversible or irretrievable commitment of resources (for example, use of scarce water resources).

(4) *Other Adverse Environmental Impacts*

You may consider significant differences in noise levels, radiant heat, or dissipated static electrical energy of pollution control alternatives. Other examples of non-air quality environmental impacts would include hazardous waste discharges such as spent catalysts or contaminated carbon.

k. How do I take into account a project's "remaining useful life" in calculating control costs?

1. You may decide to treat the requirement to consider the source's "remaining useful life" of the source for BART determinations as one element of the overall cost analysis. The "remaining useful life" of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's *OAQPS Control Cost Manual* require the use of a specified time period for amortization that varies based upon the type of control. If the remaining useful life will clearly exceed this time period, the remaining useful life has essentially no effect on control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, you should use this shorter time period in your cost calculations.

2. For purposes of these guidelines, the remaining useful life is the difference between:

(1) The date that controls will be put in place (capital and other construction costs incurred before controls are put in place can be rolled into the first year, as suggested in EPA's *OAQPS Control Cost Manual*); you are conducting the BART analysis; and

(2) The date the facility permanently stops operations. Where this affects the BART determination, this date should be assured by a federally- or State-enforceable restriction preventing further operation.

3. We recognize that there may be situations where a source operator intends to shut down a source by a given date, but wishes to retain the flexibility to continue

operating beyond that date in the event, for example, that market conditions change. Where this is the case, your BART analysis may account for this, but it must maintain consistency with the statutory requirement to install BART within 5 years. Where the source chooses not to accept a federally enforceable condition requiring the source to shut down by a given date, it is necessary to determine whether a reduced time period for the remaining useful life changes the level of controls that would have been required as BART.

If the reduced time period does change the level of BART controls, you may identify, and include as part of the BART emission limitation, the more stringent level of control that would be required as BART if there were no assumption that reduced the remaining useful life. You may incorporate into the BART emission limit this more stringent level, which would serve as a contingency should the source continue operating more than 5 years after the date EPA approves the relevant SIP. The source would not be allowed to operate after the 5-year mark without such controls. If a source does operate after the 5-year mark without BART in place, the source is considered to be in violation of the BART emissions limit for each day of operation.

5. Step 5: How should I determine visibility impacts in the BART determination?

The following is an approach you may use to determine visibility impacts (the degree of visibility improvement for each source subject to BART) for the BART determination. Once you have determined that your source or sources are subject to BART, you must conduct a visibility improvement determination for the source(s) as part of the BART determination. When making this determination, we believe you have flexibility in setting absolute thresholds, target levels of improvement, or *de minimis* levels since the deciview improvement must be weighed among the five factors, and you are free to determine the weight and significance to be assigned to each factor. For example, a 0.3 deciview improvement may merit a stronger weighting in one case versus another, so one "bright line" may not be appropriate. [Note that if sources have elected to apply the most stringent controls available, consistent with the discussion in section E. step 1. below, you need not conduct, or require the source to conduct, an air quality modeling analysis for the purpose of determining its visibility impacts.]

Use CALPUFF,[17] or other appropriate dispersion model to determine the visibility improvement expected at a Class I area from the potential BART control technology applied to the source. Modeling should be conducted for SO_2, NO_X, and direct PM emissions ($PM_{2.5}$ and/or PM_{10}). If the source is making the visibility determination, you should review and approve or disapprove of the source's analysis before making the expected improvement determination. There are several steps for determining the visibility impacts from an individual source using a dispersion model:

• Develop a modeling protocol.

Some critical items to include in a modeling protocol are meteorological and terrain data, as well as source-specific information (stack height, temperature, exit velocity, elevation, and allowable and actual emission rates of applicable pollutants), and receptor data from appropriate Class I areas. We recommend following EPA's *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts*[18] for parameter settings and meteorological data inputs; the use of other settings from those in IWAQM should be identified and explained in the protocol.

One important element of the protocol is in establishing the receptors that will be used in the model. The receptors that you use should be located in the nearest Class I area with sufficient density to identify the likely visibility effects of the source. For other Class I areas in relatively close proximity to a BART-eligible source, you may model a few strategic receptors to determine whether effects at those areas may be greater than at the nearest Class I area. For example, you might chose to locate receptors at these areas at the closest point to the source, at the highest and lowest elevation in the Class I area, at the IMPROVE monitor, and at the approximate expected plume release height. If the highest modeled effects are observed at the nearest Class I area, you may choose not to analyze the other Class I areas any further as additional analyses might be unwarranted.

You should bear in mind that some receptors within the relevant Class I area may be less than 50 km from the source while other receptors within that same Class I area may be greater than 50 km from the same source. As indicated by the *Guideline on Air Quality Models*, this situation may call for the use of two different modeling approaches for the same Class I area and source, depending upon the State's chosen method for modeling sources less than 50 km. In situations where you are assessing visibility impacts for source-receptor distances less than 50 km, you should use expert modeling judgment in determining visibility impacts, giving consideration to both CALPUFF and other EPA-approved methods.

In developing your modeling protocol, you may want to consult with EPA and your regional planning organization (RPO). Up-front consultation will ensure that key technical issues are addressed before you conduct your modeling.

• For each source, run the model, at pre-control and post-control emission rates according to the accepted methodology in the protocol.

Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario). Calculate the model results for each receptor as the change in deciviews compared against natural visibility conditions. Post-control emission rates are calculated as a percentage of pre-control emission rates. For example, if the 24-hr pre-control emission rate is 100 lb/hr of SO_2, then the post control rate is 5 lb/hr if the control efficiency being evaluated is 95 percent.

• Make the net visibility improvement determination.

Assess the visibility improvement based on the modeled change in visibility impacts for the pre-control and post-control emission scenarios. You have flexibility to assess visibility improvements due to BART controls by one or more methods. You may consider the frequency, magnitude, and duration components of impairment. Suggestions for making the determination are:

• Use of a comparison threshold, as is done for determining if BART-eligible sources should be subject to a BART determination. Comparison thresholds can be used in a number of ways in evaluating visibility improvement (*e.g.* the number of days or hours that the threshold was exceeded, a single threshold for determining whether a change in impacts is significant, or a threshold representing an x percent change in improvement).

• Compare the 98th percent days for the pre- and post-control runs.

Note that each of the modeling options may be supplemented with source apportionment data or source apportionment modeling.

E. How do I select the "best" alternative, using the results of Steps 1 through 5?

1. Summary of the Impacts Analysis

From the alternatives you evaluated in Step 3, we recommend you develop a chart (or charts) displaying for each of the alternatives:

(1) Expected emission rate (tons per year, pounds per hour);

(2) Emissions performance level (*e.g.*, percent pollutant removed, emissions per unit product, lb/MMBtu, ppm);

(3) Expected emissions reductions (tons per year);

(4) Costs of compliance—total annualized costs ($), cost effectiveness ($/ton), and incremental cost effectiveness ($/ton), and/or any other cost-effectiveness measures (such as $/deciview);

(5) Energy impacts;

(6) Non-air quality environmental impacts; and

(7) Modeled visibility impacts.

2. Selecting a "best" alternative

1. You have discretion to determine the order in which you should evaluate control options for BART. Whatever the order in which you choose to evaluate options, you should always (1) display the options evaluated; (2) identify the average and incremental costs of each option; (3) consider the energy and non-air quality environmental impacts of each option; (4) consider the remaining useful life; and (5) consider the modeled visibility impacts. You should provide a justification for adopting the technology that you select as the "best" level of control, including an explanation of the

[17] The model code and its documentation are available at no cost for download from *http://www.epa.gov/scram001/tt22.htm#calpuff.*

[18] *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts,* U.S. Environmental Protection Agency, EPA–454/R–98–019, December 1998.

CAA factors that led you to choose that option over other control levels.

2. In the case where you are conducting a BART determination for two regulated pollutants on the same source, if the result is two different BART technologies that do not work well together, you could then substitute a different technology or combination of technologies.

3. In selecting a "best" alternative, should I consider the affordability of controls?

1. Even if the control technology is cost effective, there may be cases where the installation of controls would affect the viability of continued plant operations.

2. There may be unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology. These effects would include effects on product prices, the market share, and profitability of the source. Where there are such unusual circumstances that are judged to affect plant operations, you may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology. Where these effects are judged to have a severe impact on plant operations you may consider them in the selection process, but you may wish to provide an economic analysis that demonstrates, in sufficient detail for public review, the specific economic effects, parameters, and reasoning. (We recognize that this review process must preserve the confidentiality of sensitive business information). Any analysis may also consider whether other competing plants in the same industry have been required to install BART controls if this information is available.

4. Sulfur dioxide limits for utility boilers

You must require 750 MW power plants to meet specific control levels for SO_2 of either 95 percent control or 0.15 lbs/MMBtu, for each EGU greater than 200 MW that is currently uncontrolled unless you determine that an alternative control level is justified based on a careful consideration of the statutory factors. Thus, for example, if the source demonstrates circumstances affecting its ability to cost-effectively reduce its emissions, you should take that into account in determining whether the presumptive levels of control are appropriate for that facility. For a currently uncontrolled EGU greater than 200 MW in size, but located at a power plant smaller than 750 MW in size, such controls are generally cost-effective and could be used in your BART determination considering the five factors specified in CAA section 169A(g)(2). While these levels may represent current control capabilities, we expect that scrubber technology will continue to improve and control costs continue to decline. You should be sure to consider the level of control that is currently best achievable at the time that you are conducting your BART analysis.

For coal-fired EGUs with existing post-combustion SO_2 controls achieving less than 50 percent removal efficiencies, we recommend that you evaluate constructing a new FGD system to meet the same emission limits as above (95 percent removal or 0.15 lb/mmBtu), in addition to the evaluation of scrubber upgrades discussed below. For oil-fired units, regardless of size, you should evaluate limiting the sulfur content of the fuel oil burned to 1 percent or less by weight.

For those BART-eligible EGUs with pre-existing post-combustion SO_2 controls achieving removal efficiencies of at least 50 percent, your BART determination should consider cost effective scrubber upgrades designed to improve the system's overall SO_2 removal efficiency. There are numerous scrubber enhancements available to upgrade the average removal efficiencies of all types of existing scrubber systems. We recommend that as you evaluate the definition of "upgrade," you evaluate options that not only improve the design removal efficiency of the scrubber vessel itself, but also consider upgrades that can improve the overall SO_2 removal efficiency of the scrubber system. Increasing a scrubber system's reliability, and conversely decreasing its downtime, by way of optimizing operation procedures, improving maintenance practices, adjusting scrubber chemistry, and increasing auxiliary equipment redundancy, are all ways to improve average SO_2 removal efficiencies.

We recommend that as you evaluate the performance of existing wet scrubber systems, you consider some of the following upgrades, in no particular order, as potential scrubber upgrades that have been proven in the industry as cost effective means to increase overall SO_2 removal of wet systems:

(a) Elimination of Bypass Reheat;
(b) Installation of Liquid Distribution Rings;
(c) Installation of Perforated Trays;
(d) Use of Organic Acid Additives;
(e) Improve or Upgrade Scrubber Auxiliary System Equipment;
(f) Redesign Spray Header or Nozzle Configuration.

We recommend that as you evaluate upgrade options for dry scrubber systems, you should consider the following cost effective upgrades, in no particular order:

(a) Use of Performance Additives;
(b) Use of more Reactive Sorbent;
(c) Increase the Pulverization Level of Sorbent;
(d) Engineering redesign of atomizer or slurry injection system.

You should evaluate scrubber upgrade options based on the 5 step BART analysis process.

5. Nitrogen oxide limits for utility boilers

You should establish specific numerical limits for NO_X control for each BART determination. For power plants with a generating capacity in excess of 750 MW currently using selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) for part of the year, you should presume that use of those same controls year-round is BART. For other sources currently using SCR or SNCR to reduce NO_X emissions during part of the year, you should carefully consider requiring the use of these controls year-round as the additional costs of operating the equipment throughout the year would be relatively modest.

For coal-fired EGUs greater than 200 MW located at greater than 750 MW power plants and operating without post-combustion controls (*i.e.* SCR or SNCR), we have provided presumptive NO_X limits, differentiated by boiler design and type of coal burned. You may determine that an alternative control level is appropriate based on a careful consideration of the statutory factors. For coal-fired EGUs greater than 200 MW located at power plants 750 MW or less in size and operating without post-combustion controls, you should likewise presume that these same levels are cost-effective. You should require such utility boilers to meet the following NO_X emission limits, unless you determine that an alternative control level is justified based on consideration of the statutory factors. The following NO_X emission rates were determined based on a number of assumptions, including that the EGU boiler has enough volume to allow for installation and effective operation of separated overfire air ports. For boilers where these assumptions are incorrect, these emission limits may not be cost-effective.

TABLE 1.—PRESUMPTIVE NO_X EMISSION LIMITS FOR BART-ELIGIBLE COAL-FIRED UNITS.[19]

Unit type	Coal type	NO_X presumptive limit (lb/mmbtu)[20]
Dry-bottom wall-fired	Bituminous	0.39
	Sub-bituminous	0.23
	Lignite	0.29
Tangential-fired	Bituminous	0.28
	Sub-bituminous	0.15
	Lignite	0.17
Cell Burners	Bituminous	0.40
	Sub-bituminous	0.45
Dry-turbo-fired	Bituminous	0.32
	Sub-bituminous	0.23
Wet-bottom tangential-fired	Bituminous	0.62

MostEGUs can meet these presumptive NO_x limits through the use of current combustion control technology, *i.e.* the careful control of combustion air and low-NO_X burners. For units that cannot meet these limits using such technologies, you should consider whether advanced combustion control technologies such as rotating opposed fire air should be used to meet these limits.

Because of the relatively high NO_X emission rates of cyclone units, SCR is more cost-effective than the use of current combustion control technology for these units. The use of SCRs at cyclone units burning bituminous coal, sub-bituminous coal, and lignite should enable the units to cost-effectively meet NO_X rates of 0.10 lbs/mmbtu. As a result, we are establishing a presumptive NO_X limit of 0.10 lbs/mmbtu based on the use of SCR for coal-fired cyclone units greater than 200 MW located at 750 MW power plants. As with the other presumptive limits established in this guideline, you may determine that an alternative level of control is appropriate based on your consideration of the relevant statutory factors. For other cyclone units, you should review the use of SCR and consider whether these post-combustion controls should be required as BART.

For oil-fired and gas-fired EGUs larger than 200MW, we believe that installation of current combustion control technology to control NO_X is generally highly cost-effective and should be considered in your determination of BART for these sources. Many such units can make significant reductions in NO_X emissions which are highly cost-effective through the application of current combustion control technology.[21]

V. Enforceable Limits/Compliance Date

To complete the BART process, you must establish enforceable emission limits that reflect the BART requirements and require compliance within a given period of time. In particular, you must establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source. In addition, you must require compliance with the BART emission limitations no later than 5 years after EPA approves your regional haze SIP. If technological or economic limitations in the application of a measurement methodology to a particular emission unit make a conventional emissions limit infeasible, you may instead prescribe a design, equipment, work practice, operation standard, or combination of these types of standards. You should consider allowing sources to "average" emissions across any set of BART-eligible emission units within a fenceline, so long as the emission reductions from each pollutant being controlled for BART would be equal to those reductions that would be obtained by simply controlling each of the BART-eligible units that constitute BART-eligible source.

You should ensure that any BART requirements are written in a way that clearly specifies the individual emission unit(s) subject to BART regulation. Because the BART requirements themselves are "applicable" requirements of the CAA, they must be included as title V permit conditions according to the procedures established in 40 CFR part 70 or 40 CFR part 71.

Section 302(k) of the CAA requires emissions limits such as BART to be met on a continuous basis. Although this provision does not necessarily require the use of continuous emissions monitoring (CEMs), it is important that sources employ techniques that ensure compliance on a continuous basis. Monitoring requirements generally applicable to sources, including those that are subject to BART, are governed by other regulations. See, *e.g.*, 40 CFR part 64 (compliance assurance monitoring); 40 CFR 70.6(a)(3) (periodic monitoring); 40 CFR 70.6(c)(1) (sufficiency monitoring). Note also that while we do not believe that CEMs would necessarily be required for all BART sources, the vast majority of electric generating units potentially subject to BART already employ CEM technology for other programs, such as the acid rain program. In addition, emissions limits must be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements). In light of the above, the permit must:

- Be sufficient to show compliance or noncompliance (*i.e.*, through monitoring times of operation, fuel input, or other indices of operating conditions and practices); and
- Specify a reasonable averaging time consistent with established reference methods, contain reference methods for determining compliance, and provide for adequate reporting and recordkeeping so that air quality agency personnel can determine the compliance status of the source; and
- For EGUS, specify an averaging time of a 30-day rolling average, and contain a definition of "boiler operating day" that is consistent with the definition in the proposed revisions to the NSPS for utility boilers in 40 CFR Part 60, subpart Da.[22] You should consider a boiler operating day to be any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit. This would allow 30-day rolling average emission rates to be calculated consistently across sources.

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[19] No Cell burners, dry-turbo-fired units, nor wet-bottom tangential-fired units burning lignite were identified as BART-eligible, thus no presumptive limit was determined. Similarly, no wet-bottom tangential-fired units burning sub-bituminous were identified as BART-eligible.

[20] These limits reflect the design and technological assumptions discussed in the technical support document for NO_X limits for these guidelines. See *Technical Support Document for BART NO_X Limits for Electric Generating Units and Technical Support Document for BART NO_X* Limits for Electric Generating Units Excel Spreadsheet, Memorandum to Docket OAR 2002–0076, April 15, 2005.

[21] See *Technical Support Document for BART NO_X Limits for Electric Generating Units* and *Technical Support Document for BART NO_X Limits for Electric Generating Units Excel Spreadsheet*, Memorandum to Docket OAR 2002–0076, April 15, 2005.

[22] 70 FR 9705, February 28, 2005.