Monday through Friday, except Federal holidays. The Docket Office (telephone (800) 647–5527) is located at the street address stated in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

List of Subjects in 14 CFR Part 39

Air transportation, Aircraft, Aviation safety, Incorporation by reference, Safety.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 14 CFR part 39 as follows:

PART 39—AIRWORTHINESS DIRECTIVES

1. The authority citation for part 39 continues to read as follows:

Authority: 49 U.S.C. 106(g), 40113, 44701.

§ 39.13 [Amended]

2. The FAA amends § 39.13 by removing Airworthiness Directive (AD) 91–18–19, Amendment 39–8022 (56 FR 42224, August 24, 1991), and adding the following new AD:

Hawker Beechcraft Corporation (Type Certificate Numbers 3A15, 3A16, and A23CE formerly held by Raytheon Aircraft Company; formerly held by Beech Aircraft Corporation):Docket No. FAA–2009–0797; Directorate Identifier 2009–CE–032–AD.

Comments Due Date

(a) We must receive comments on this airworthiness directive (AD) action by October 27, 2009.

Affected ADs

(b) This AD supersedes AD 91–18–19, Amendment 39–8022.

Applicability

(c) This AD applies to the following airplane models and serial numbers that are certificated in any category:

(1) *Group 1 Airplanes* (retains the actions and applicability from AD 91–18–19):

Model	Serial Nos. (SNs)
58, 58A	TH–733 through TH–1609.
58P, 58PA	TJ–3 through TJ–497.
58TC, 58TCA	TK–1 through TK–151.
95–B55, 95–B55A.	TC–1947 through TC–2456.
A36	E–825 through E–2578.
B36TC	EA–242 and EA–273 through EA–509.
E55, E55A	TE–1078 through TE–1201.
F33A	CE–634 through CE–1536.
V35B	D–9862 through D–10403.

(2) *Group 2 Airplanes* (aligns certain SNs applicability to Models A36TC airplanes):

Model	SNs
A36TC	EA–1 through EA–241 and EA–243 through EA–272.

Unsafe Condition

(d) This AD results from reports of incorrect washers installed in the pilot and copilot shoulder harnesses on certain Beech 33, 35, 36, 55, 58, and 95 series airplanes. We are issuing this AD to detect and correct an incorrect washer installed in the pilot and copilot shoulder harnesses. This failure could result in a malfunctioning shoulder harness. Such a failure could lead to occupant injury.

Compliance

(e) To address this problem, you must do the following, unless already done:

Actions	Compliance	Procedures
(1) Inspect the washers on the "D" ring of the pilot and copilot shoulder harnesses for correct metal, inner and outer diameter, and thickness.	(i) *For Group 1 Airplanes:* Within the next 100 hours time-in-service (TIS) after October 21, 1991 (the effective date of AD 91–18–19). (ii) *For Group 2 Airplanes:* Within the next 100 hours TIS after the effective date of this AD.	Follow Beechcraft Mandatory Service Bulletin No. 2394, dated December 1990.
(2) If you find, as a result of the inspection required by paragraph (e)(1) of this AD, any washer does not meet the criteria for correct metal, inner and outer diameter, and thickness, replace the incorrect washer with part number 100951X060YA washer.	Before further flight, after the inspection required by paragraph (e)(1) of this AD.	Follow Beechcraft Mandatory Service Bulletin No. 2394, dated December 1990.

Alternative Methods of Compliance (AMOCs)

(f) The Manager, Wichita Aircraft Certification Office (ACO), FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. Send information to ATTN: Steve Potter, Aerospace Engineer, ACE–118W, Wichita Aircraft Certification Office (ACO), 1801 Airport Road, Room 100, Wichita, Kansas 67209; telephone: (316) 946–4124; fax: (316) 946–4107. Before using any approved AMOC on any airplane to which the AMOC applies, notify your appropriate principal inspector (PI) in the FAA Flight Standards District Office (FSDO), or lacking a PI, your local FSDO.

(g) In reviewing the docket and project files, we found no AMOCs submitted for AD 91–18–19. Since there are no AMOCs approved for AD 91–18–19 to approve for this AD, transfer of AMOCs to this AD does not apply.

Related Information

(h) To get copies of the service information referenced in this AD, contact Hawker Beechcraft Corporation, P.O. Box 85, Wichita, Kansas 67201–0085; telephone: (800) 429–5372 or (316) 676–3140; Internet: *http://pubs.hawkerbeechcraft.com.* To view the AD docket, go to U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue, SE., Washington, DC 20590, or on the Internet at *http://www.regulations.gov.*

Issued in Kansas City, Missouri, on August 20, 2009.

Kim Smith,

Manager, Small Airplane Directorate, Aircraft Certification Service.

[FR Doc. E9–20832 Filed 8–27–09; 8:45 am]

BILLING CODE 4910–13–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 49

[EPA–R09–OAR–2009–0598; FRL–8950–6]

Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advanced Notice of Proposed Rulemaking

AGENCY: Environmental Protection Agency (EPA).

ACTION: Advanced Notice of Proposed Rulemaking.

SUMMARY: The Environmental Protection Agency is providing an Advanced Notice of Proposed Rulemaking (ANPR)

concerning the anticipated visibility improvements and the cost effectiveness for different levels of air pollution controls as Best Available Retrofit Technology (BART) for two coal-fired power plants, Four Corners Power Plant (FCPP) and Navajo Generating Station (NGS), located on the Navajo Nation. This ANPR briefly describes the provisions in Part C, Subpart II of the Clean Air Act (CAA or Act), EPA's implementing regulations, and the Tribal Authority Rule (TAR) for promulgating Federal Implementation Plans (FIPs) to protect visibility in national parks and wilderness areas known as Class I Federal areas.

The specific purpose of this ANPR is for EPA to collect additional information that we may consider in modeling the degree of anticipated visibility improvements in the Class I areas surrounding FCPP and NGS and for determining whether BART controls are cost effective at this time. EPA is also requesting any additional information that any person believes the agency should consider in promulgating a FIP establishing BART for FCPP and NGS.

EPA intends to publish separate FIPs proposing our BART determinations for FCPP and NGS approximately 60 days after receiving information from this ANPR. EPA will not respond to comments or information submitted in response to this ANPR. The information submitted in response to this ANPR will be used in developing the subsequent proposed FIPs containing our detailed BART determinations for FCPP and NGS.

The FCPP and NGS FIP proposals following this ANPR will request further public comment. During the public comment period for the proposed FIPs containing the FCPP and NGS BART determinations, EPA intends to hold separate public hearings at locations to be determined near each facility.

EPA will not hold a public hearing for this ANPR. This ANPR also serves to begin EPA's 60-day consultation period with the Federal Land Managers (FLMs) within the Departments of Interior and Agriculture. Information necessary to initiate consultation is contained in this ANPR and supporting documentation included in the docket for this ANPR. EPA will address any matters raised by the FLMs in this 60-day consultation period when we propose the BART FIPs for FCPP and NGS.

DATES: Comments on this ANPR must be submitted no later than September 28, 2009.

ADDRESSES: Submit comments, identified by docket number EPA–R09–OAR–2009–0598, by one of the following methods:

1. *Federal eRulemaking Portal: www.regulations.gov.* Follow the on-line instructions.
2. *E-mail: lee.anita@epa.gov.*
3. *Mail or delivery:* Anita Lee (Air-3), U.S. Environmental Protection Agency Region IX, 75 Hawthorne Street, San Francisco, CA 94105–3901.

Instructions: All comments will be included in the public docket without change and may be made available online at *www.regulations.gov*, including any personal information provided, unless the comment includes Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Information that you consider CBI or otherwise protected should be clearly identified as such and should not be submitted through *www.regulations.gov* or e-mail. *www.regulations.gov* is an ''anonymous access'' system, and EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send e-mail directly to EPA, your e-mail address will be automatically captured and included as part of the public comment. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment.

Docket: The index to the docket for this action is available electronically at *www.regulations.gov* and in hard copy at EPA Region IX, 75 Hawthorne Street, San Francisco, California. While all documents in the docket are listed in the index, some information may be publicly available only at the hard copy location (*e.g.*, copyrighted material), and some may not be publicly available in either location (*e.g.*, CBI). To inspect the hard copy materials, please schedule an appointment during normal business hours with the contact listed in the **FOR FURTHER INFORMATION CONTACT** section.

FOR FURTHER INFORMATION CONTACT: Anita Lee, EPA Region IX, (415) 972–3958, *lee.anita@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document, ''we'', ''us'', and ''our'' refer to EPA.

Table of Contents

I. Background

A. Statutory and Regulatory Framework for Addressing Visibility

Part C, Subsection II, of the Act, establishes a visibility protection program that sets forth ''as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from man-made air pollution.'' 42 U.S.C. 7491A(a)(1). The terms ''impairment of visibility'' and ''visibility impairment'' are defined in the Act to include a reduction in visual range and atmospheric discoloration. Id. 7491A(g)(6). A fundamental requirement of the program is for EPA, in consultation with the Secretary of the Interior, to promulgate a list of ''mandatory Class I Federal areas'' where visibility is an important value. Id. 7491A(a)(2). These areas include national wilderness areas and national parks greater than six thousand acres in size. Id. 7472(a).

On November 30, 1979, EPA identified 156 mandatory Class I Federal areas, including for example: Grand Canyon National Park in Arizona (40

CFR 81.403); Mesa Verde National Park and La Garita Wilderness Area in Colorado (Id. 81.406); Bandolier Wilderness Area in New Mexico (Id. 81.421); and Arches, Bryce Canyon, Canyonlands and Capitol Reef National Parks in Utah (Id. 81.430). All of these mandatory Class I Federal areas and many others are within a 300-km radius of either FCPP or NGS.

On December 2, 1980, EPA promulgated what it described as the first phase of the required visibility regulations, codified at 40 CFR 51.300–51.307 (45 FR 80084). The 1980 regulations deferred regulating regional haze from multiple sources finding that the scientific data was inadequate at that time. Id. at 80086.

Congress added Section 169B to the Act in the 1990 Amendments, requiring EPA to take further action to reduce visibility impairment in broad geographic regions. 42 U.S.C. 7492. In 1993, the National Academy of Sciences released a comprehensive study [1] required by the 1990 Amendments concluding that ''current scientific knowledge is adequate and control technologies are available for taking regulatory action to improve and protect visibility.''

EPA first promulgated regulations to address regional haze on April 22, 1999. 64 FR 35765 (April 22, 1999). EPA's 1999 regional haze regulations included a provision requiring States to review BART-eligible sources for potentially mandating further air pollution controls. Congress defined BART-eligible sources as ''each major station stationary source which is in existence on August 7, 1977, but which has not been in operation for more than fifteen years as of such date'' which emits pollutants that are reasonably anticipated to cause or contribute to visibility impairment. 42 U.S.C. 7479(b)(2)(A).

EPA's 1999 regulations followed the five factor approach set forth in the statutory definition of BART. However, the regulations treated the fifth factor, the degree of visibility improvement, on an area-wide rather than source specific basis. 64 FR 35741. The Court remanded the 1999 regulations to EPA on that issue. *American Corn Growers Assoc.* v. *EPA,* 291 F.3d 1 (DC Cir. 2002). EPA promulgated revisions to the regulations in June 2003, which were remanded on narrow grounds not relevant to this action. *Center for Energy and Economic Development* v. *EPA,* 398 F.3d 653 (DC Cir. 2005). Finally, EPA revised regional haze regulations in March 2005, which were upheld by the Court of Appeals for the District of Columbia Circuit. *Utility Air Regulatory Group* v. *EPA,* 471 F.3d 1333 (DC Cir. 2006).

B. Statutory and Regulatory Framework for Addressing Sources Located on Tribal Lands

The 1990 Amendments included Section 301(d)(4) of the Act directing EPA to promulgate regulations for controlling air pollution on Tribal lands. EPA promulgated regulations to implement this Congressional directive, known as the Tribal Authority Rule (TAR), in 1998. 63 FR 7264 (1998) codifed at 40 CFR 49.1–49.11. *See generally Arizona Public Service* v. *EPA,* 211 F.3d 1280 (DC Cir. 2000).

Section 49.11 of the TAR authorizes EPA to promulgate a FIP when EPA determines such regulations are ''necessary or appropriate'' to protect air quality. 40 CFR 49.11(a). Pursuant to the authority in the TAR, EPA promulgated a source specific FIP for FCPP 2006. The Court of Appeals for the Tenth Circuit considered the regulatory language in 40 CFR 49.11(a) and concluded that ''[i]t provides the EPA discretion to determine what rulemaking is necessary or appropriate to protect air quality and requires the EPA to promulgate such rulemaking.'' *Arizona Public Service* v. *EPA,* 562 F.3d 1116 (10th Cir. 2009).

C. Statutory and Regulatory Framework for BART Determinations

FCPP and NGS are the only BART eligible sources located on the Navajo Nation. EPA's guidelines for evaluating BART are set forth in Appendix Y to 40 CFR Part 51. The Guidelines include a ''five factor'' analysis for BART determinations. Id. at IV.A. Those factors, from the definition of BART, are: (1) Costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any pollution control equipment in use or in existence 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. 40 CFR 51.308(e)(1)(ii)(A).

D. EPA's Intended Action Subsequent to the ANPR

After receiving information from this ANPR, EPA intends to propose separate FIPs for FCPP and NGS containing our determination of what level of control technology is BART for each power plant. EPA has determined it has authority to promulgate these FIPs under CAA Section 301(d)(4), 40 CFR Part 49.11, and 40 CFR 51.308(e). Any person may submit information concerning EPA's authority during the 30 day comment period for this ANPR.

As discussed more fully below, EPA is specifically seeking information in this ANPR on two of the listed considerations in the five factor test: (1) The data inputs to model the degree of improvement in visibility which may reasonably be anticipated from different levels of air pollution controls as BART and (2) the costs of compliance of those potential BART controls. We anticipate that those two factors will generate the most comments on our subsequent proposed BART FIPs for FCPP and NGS. Information on the other three factors in the five factor test may also be submitted in response to this ANPR.

E. Factual Background

1. Four Corners Power Plant

FCPP is a privately owned and operated coal-fired power plant located on the Navajo Nation Indian Reservation near Farmington, New Mexico. Based on lease agreements signed in 1960, FCPP was constructed and has been operating on real property held in trust by the Federal government for the Navajo Nation. The facility consists of five coal-fired electric utility steam generating units with a total capacity of 2060 megawatts (MW). Units 1, 2, and 3 at FCPP are owned entirely by Arizona Public Service (APS), which serves as the facility operator, and are rated to 170 MW (Units 1 and 2) and 220 MW (Unit 3). Units 4 and 5 are each rated to a capacity of 750 MW, and are co-owned by six entities: Southern California Edison (48%), APS (15%), Public Service Company of New Mexico (13%), Salt River Project (SRP) (10%), El Paso Electric Company (7%), and Tucson Electric Power (7%).

Based on 2006 emissions data from the EPA Clean Air Markets Division,[2] FCPP is the largest source of NO_X emissions in the United States (nearly 45,000 tons per year (tpy) of NO_X).

FCPP, located near the Four Corners region of Arizona, New Mexico, Utah, and Colorado, is within 300 kilometers (km) of sixteen mandatory Class I areas: Arches National Park (NP), Bandolier National Monument (NM), Black Canyon of the Gunnison Wilderness Area (WA), Canyonlands NP, Capitol Reef NP, Grand Canyon NP, Great Sand Dunes NP, La Garita WA, Maroon Bells-Snowmass WA, Mesa Verde NP, Pecos WA, Petrified Forest NP, San Pedro Parks WA, West Elk WA, Weminuche WA, and Wheeler Park WA. APS

[1] ''Protecting Visibility in National Parks and Wilderness Areas'', Committee on Haze in National Parks and Wilderness Areas, National Research Council, National Academy Press (1993).

[2] ''Clean Air Markets—Data and Maps'' at *http://camddataandmaps.epa.gov/gdm/.*

provided information relevant to a BART analysis to EPA on January 29, 2008. The information consisted of a BART engineering and cost analysis conducted by Black and Veatch (B&V) dated December 4, 2007 (Revision 3), a BART visibility modeling protocol prepared by ENSR Corporation (now called AECOM and will be referred to as AECOM throughout this document) dated January 2008, a BART visibility modeling report prepared by AECOM dated January 2008, and APS BART Analysis conclusions, dated January 29, 2008. APS provided supplemental information on cost and visibility modeling in correspondence dated May 28, 2008, June 10, 2008, November 2008, and March 16, 2009.

2. Navajo Generating Station

NGS is a coal-fired power plant located on the Navajo Nation Indian Reservation, just east of Page, Arizona, approximately 135 miles north of Flagstaff, Arizona. The facility is co-owned by six different entities: U.S. Bureau of Reclamation (24.3%), SRP, which also acts as the facility operator (21.7%), Los Angeles Department of Water and Power (21.2%), APS (14%), Nevada Power Company (11.3%), and Tucson Electric Power (7.5%).

Based on 2006 emissions data from the EPA Clean Air Markets Division, NGS is the fourth largest source of NO_X emissions in the United States (nearly 35,000 tpy). NGS, in northern Arizona, is located within 300 km of eleven Class I areas: Arches NP, Bryce Canyon NP, Canyonlands NP, Capitol Reef NP, Grand Canyon NP, Mazatzal WA, Mesa Verde NP, Petrified Forest NP, Pine Mountain WA, Sycamore Canyon WA, and Zion NP.

SRP submitted to EPA a BART modeling protocol prepared by AECOM dated September 2007, and a BART Analysis, conducted by AECOM, dated November 2007. SRP provided supplemental information regarding cost on July 29, 2008, a revised BART Analysis, dated December 2008, and additional information regarding modeling and emission control rates on June 3, 2009.

3. Relationship of NO_X and PM to Visibility Impairment

Particulate matter (PM) less than 10 microns (millionths of a meter) in size interacts with light. The smallest particles in the 0.1 to 1 micron range interact most strongly as they are about the same size as the wavelengths of visible light. The effect of the interaction is to scatter light from its original path. Conversely, for a given line of sight, such as between a mountain scene and an observer, light from many different original paths is scattered into that line. The scattered light appears as whitish haze in the line of sight, obscuring the view.

PM emitted directly into the atmosphere, also called primary PM, for example from materials handling, tends to be coarse, *i.e.* around 10 microns, since it is created from the breakup of larger particles of soil and rock. PM that is formed in the atmosphere from the condensation of gaseous chemical pollutants, also called secondary PM, tends to be fine, *i.e.* smaller than 1 micron, since they are formed from the buildup of individual molecules. Thus, secondary PM tends to contribute more to visibility impairment than primary PM because it is in the size range where it most effectively interacts with visible light. NO_X and ammonia are two examples of precursors to secondary PM.

NO_X is a gaseous pollutant that can be oxidized to form nitric acid. In the atmosphere, nitric acid in the presence of ammonia can form particulate ammonium nitrate. The formation of ammonium nitrate is also dependent on temperature and relative humidity. Particulate ammonium nitrate can grow into the size range that effectively interacts with light by coagulating together and by taking on additional pollutants and water. The same principle applies to SO_2 and the formation of particulate ammonium sulfate.

In air quality models, secondary PM is tracked separately from primary PM because the amount of secondary PM formed depends on weather conditions and because it can be six times more effective at impairing visibility. This is reflected in the equation used to calculate visibility impact from concentrations measured by the Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring network covering Class I areas.[3]

II. Request for Public Comment

A. Factor 1: Cost of Compliance

1. FCPP

a. Estimated Cost of Controls

APS, through its contractor B&V, evaluated the BART cost of compliance analysis using the EPA Coal Utility Environmental Cost (CUECost) program, information supplied by equipment vendors, estimates from previous projects, and projected costs from FCPP. The cost estimates provided by APS (updated in the March 16, 2009 submission to EPA) are included in Table 1 for four different levels of control technology to reduce NO_X and in Table 2 for four different levels of control options to reduce PM on Units 1–3. The NO_X control technology options in Table 1 are: (1) Low NO_X Burners (LNB) on Units 1 and 2 and LNB plus overfire air (OFA) on Units 3–5; (2) selective catalytic reduction (SCR) on all units (units 1–5); (3) SCR plus LNB on all units (Units 1–5); and (4) SCR plus LNB + OFA on all units (units 1–5). The PM control options for Units 1–3 [4] are: (1) Electrostatic precipitators (ESP) upstream of current air quality control equipment, *i.e.,* venturi scrubbers; (2) pulse jet fabric filter (baghouse) upstream of current air quality control equipment; (3) wet metal ESP downstream of venturi scrubber, and (4) wet membrane ESP downstream of venturi scrubber.

TABLE 1—FCPP COSTS OF COMPLIANCE FOR NO_X BASED ON APS'S ANALYSIS

	LNB/LNB + OFA [5]	SCR	SCR + LNB	SCR + LNB + OFA
Total Capital Investment				
Unit 1 ...	$4,109,000	$110,664,000	$111,609,000	$112,058,000
Unit 2 ...	4,109,000	119,010,000	121,066,000	121,496,000
Unit 3 ...	4,701,000	113,084,000	115,420,000	114,851,000
Unit 4 ...	15,260,000	265,406,000	273,892,000	279,444,000

[3] Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule, U.S. Environmental Protection Agency'', EPA–454/B–03–005, September 2003; *http://www.epa.gov/ttn/oarpg/t1pgm.html.*

[4] PM emissions from Units 4 and 5 at FCPP are already controlled by baghouses.

TABLE 1—FCPP COSTS OF COMPLIANCE FOR NO_X BASED ON APS'S ANALYSIS—Continued

	LNB/LNB + OFA [5]	SCR	SCR + LNB	SCR + LNB + OFA
Unit 5 ...	15,260,000	265,406,000	273,892,000	279,444,000
Total Annual Costs				
Unit 1 ...	$922,000	$22,297,000	$21,764,000	$21,685,000
Unit 2 ...	922,000	23,634,000	23,468,000	23,385,000
Unit 3 ...	1,055,000	23,173,000	23,010,000	22,729,000
Unit 4 ...	3,447,000	55,755,000	56,883,000	57,237,000
Unit 5 ...	3,447,000	55,755,000	56,883,000	57,237,000

TABLE 2—FCPP COSTS OF COMPLIANCE FOR PM BASED ON APS'S ANALYSIS

	Upstream [6] ESP	Upstream baghouse	Wet metal ESP	Wet membrane ESP
Total Capital Investment				
Unit 1 ...	$37,236,000	$50,515,000	$32,136,000	$23,360,000
Unit 2 ...	45,702,000	60,992,000	32,879,000	23,901,000
Unit 3 ...	40,135,000	59,594,000	59,594,000 [7]	26,988,000
Total Annual Costs				
Unit 1 ...	$10,169,000	$13,950,000	$8,781,000	$5,652,000
Unit 2 ...	11,011,000	14,481,000	8,972,000	6,658,000
Unit 3 ...	10,925,000	16,559,000	10,309,000	7,557,000

b. Cost Effectiveness of Controls

To determine the cost effectiveness of controls, typically expressed in cost per ton of pollutant reduced ($/ton), estimating the amount of NO_X and PM that will be reduced from the various control options is necessary. The estimated reduction of the pollutant is determined by establishing the baseline emissions and the degree of emissions reduction from the control technology. 40 CFR Part 51, App. Y, Step 4, c.

APS estimated NO_X emissions reductions by starting with baseline emission rates of NO_X of: 0.78 pounds of NO_X per million BTU heat input (lb/MMBtu) for Unit 1; 0.64 lb/MMBtu for Unit 2; 0.59 lb/MMBtu for Unit 3; and 0.49 lb/MMBtu from Units 4 and 5 each. For the four control technology options, APS estimated FCPP could achieve the following emissions reductions: (1) LNB on Units 1 and 2 would reduce NO_X 45% and 33%, respectively and LNB + OFA on Units 3, and 4–5 would reduce NO_X 44% and 29%, respectively; (2) SCR on Units 1–5 would reduce NO_X approximately 88–91%; (3) SCR + LNB on Units 1–5 would reduce NO_X by 88–93%; and (4) SCR + LNB + OFA on Units 1–5 would reduce NO_X by approximately 88—93%.

APS estimated PM emissions reductions using baseline emission rates of PM of: 0.025 lb/MMBtu for Unit 1; 0.029 lb/MMBtu for Unit 2; and 0.029 lb/MMBtu for Unit 3. APS estimated that the four different PM control options would all achieve 52% control on Unit 1 and 59% control on Units 2 and 3.

Table 3 lists the reduction in NO_X emissions and cost effectiveness estimated by APS for the four control technology options listed in Table 1. Table 4 provides the corresponding estimates for PM.

TABLE 3—FCPP EMISSIONS REDUCTIONS AND COST EFFECTIVENESS FOR NO_X

	LNB/LNB + OFA [8]	SCR	SCR + LNB	SCR + LNB + OFA
Tons of NO_X Reduced per Year (tpy)				
Unit 1 ...	2,569	5,138	5,285	5,285
Unit 2 ...	1,573	4,344	4,344	4,344
Unit 3 ...	2,465	5,025	5,025	5,023
Unit 4 ...	3,798	11,665	11,665	11,665
Unit 5 ...	3,798	11,665	11,665	11,665
Cost Effectiveness of Controls ($/ton)				
Unit 1 ...	359	4,343	4,118	4,103
Unit 2 ...	586	5,484	5,403	5,384
Unit 3 ...	428	4,582	4,579	4,523

[5] Capital and annual cost values are for LNB on Units 1 and 2, and LNB + OFA on Units 3–5.

[6] Upstream refers to a location before the existing venturi scrubbers.

[7] This estimate was reported by APS in their December 2007 analysis. EPA believes this value was reported by APS in error because it is unlikely a wet ESP would equal the cost of a baghouse for Unit 3, but not Units 1 and 2.

TABLE 3—FCPP EMISSIONS REDUCTIONS AND COST EFFECTIVENESS FOR NO_X—Continued

	LNB/LNB + OFA [8]	SCR	SCR + LNB	SCR + LNB + OFA
Unit 4 ...	908	4,872	4,780	4,907
Unit 5 ...	908	4,872	4,780	4,907

TABLE 4—FCPP EMISSIONS REDUCTIONS AND COST EFFECTIVENESS FOR PM

	Upstream ESP	Upstream baghouse	Wet metal ESP	Wet membrane ESP
Tons of PM Reduced per Year (tpy)				
Unit 1 ...	95	95	95	95
Unit 2 ...	127	127	127	127
Unit 3 ...	161	161	161	161
Cost Effectiveness of Controls ($/ton)				
Unit 1 ...	106,571	146,195	92,024	59,233
Unit 2 ...	86,485	113,739	70,470	52,294
Unit 3 ...	67,785	102,741	63,963	46,888

EPA's regulations recommend using the EPA's Office of Air Quality Planning and Standards' Air Pollution Cost Control Manual (Sixth Edition, January 2002) for estimating costs of compliance. 40 CFR Part 51, App. Y, Step 4.a.4. The Air Pollution Cost Control Manual provides guidance and methodologies for developing accurate and consistent estimates of cost for air pollution control devices. The costs that may be estimated include capital costs, operation and maintenance expenses, and other annual costs. Chapter 2 (Cost Estimation: Concepts and Methodology) states that total capital costs may include equipment costs, freight, sales tax, and installation costs. For existing facilities, retrofit costs should also be considered, and may include auxiliary equipment, handling and erection, piping, insulation, painting, site preparation, off-site facilities, engineering, and lost production revenue. Finally, annual costs are estimated from costs of raw materials, maintenance labor and materials, utilities, waste treatment and disposal, replacement materials, overhead, property taxes, insurance, and administrative charges.

For the estimated costs that FCPP submitted, in Tables 1 & 2 above, APS provided line-item estimates for the direct and indirect capital costs, as well as direct and indirect annual costs. APS's estimate, however, included several costs that are not included in the EPA Air Pollution Cost Control Manual, including costs of unintended consequences, such as new Continuous Emission Monitors (CEMs) and costs of Relative Accuracy Test Audits (RATA) for the CEMs. Additionally, FCPP included costs of performance tests and ''owner's costs'' in the indirect capital investment, such as financing, project management, and construction support costs, as well as legal assistance, permits and offsets, and public relations costs.

In reviewing APS's estimate, EPA found that the ratio of annual costs to the total capital costs for all control technologies projected by APS are considerably higher than those projected by other facilities that were amortized over the same 20 year time frame. For example, the total capital investment of SCR for Units 4 and 5 at FCPP is comparable to the most costly SCR retrofit (Unit 2) at NGS. However, total annual costs for FCPP are approximately 20% of the total capital costs for NO_X control, and approximately 17–28% of total capital costs for PM control. In contrast, the total annual cost estimates by NGS for LNB and SCR are approximately 12–14% of the total capital costs. Other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12–15% of total capital investments.

In Tables 5 and 6, EPA re-calculated the total annual cost of the NO_X and PM control technologies based on an annual to capital cost ratio of 15% to be consistent with annual costs estimated by other facilities. EPA did not adjust APS's estimates for capital costs.

TABLE 5—FCPP COSTS OF COMPLIANCE FOR NO_X BASED ON EPA REVISIONS

	LNB/LNB + OFA	SCR	SCR + LNB	SCR + LNB + OFA
Total Annual Costs				
Unit 1	$616,350	$16,599,600	$16,741,350	$16,808,700
Unit 2	616,350	17,851,500	18,159,900	18,224,400
Unit 3	705,150	16,962,600	17,313,000	17,227,650
Unit 4	2,289,000	39,810,900	39,810,900	41,916,600
Unit 5	2,289,000	39,810,900	39,810,900	41,916,600

[8] Capital and annual cost values are for LNB on Units 1 and 2, and LNB + OFA on Units 3–5.

TABLE 6—FCPP COSTS OF COMPLIANCE FOR PM BASED ON EPA REVISIONS

	Upstream ESP	Upstream baghouse	Wet metal ESP	Wet membrane ESP
Total Annual Costs				
Unit 1	$5,585,400	$7,577,250	$4,820,400	$3,504,000
Unit 2	6,855,300	9,148,800	4,931,850	3,585,150
Unit 3	6,020,250	8,939,100	8,939,100	4,048,200

In addition to the total annual cost, other factors, such as estimated control efficiency and how the emissions reductions are calculated influence the cost effectiveness of controls. See 40 CFR Part 51, App. Y, Step 4.a.4. APS estimated that SCR could achieve NO_X control of approximately 90% or greater from the baseline emissions. For new facilities, 90% or greater reduction in NO_X from SCR can be reasonably expected. See May 2009 White Paper on SCR from Institute of Clean Air Companies.[9] For SCR retrofits on an existing coal-fired power plant, Arizona Department of Environmental Quality (ADEQ) determined that 75% control from SCR (following upstream reductions by LNB) was appropriate for the Coronado Generating Station in Arizona.[10] Based on this data, EPA has determined that an 80% control efficiency for SCR alone, rather than the 90+% control assumed by APS, is appropriate. Accordingly, EPA calculated post-SCR control NO_X emissions from FCPP to be higher than the values of 0.06 and 0.08 lb/MMBtu used by APS, ranging from 0.10 lb/MMBtu from Units 4 or 5 to a maximum of 0.16 lb/MMBtu from Unit 1.

APS reported baseline PM emissions from Unit 3 to be 0.029 lb/MMBtu, however, EPA has determined that 0.05 lb/MMBtu for Unit 3 is the appropriate emission rate to use based on source test information collected in October 2007. PM emissions determined from three one-hour test runs on October 19, 2007 were 0.041 lb/MMbtu, 0.372 lb/MMbtu, and 0.121 lb/MMbtu. APS shut down Unit 3 for repairs after receiving the test results. Subsequent testing when the unit was brought back on line showed the unit barely met its 0.05 lb/MMbtu emission limit. Prior year test results for Unit 3 have also shown emissions at or near the 0.05 lb/MMBtu limit.

Tables 7 and 8 contain EPA's re-calculated emissions reductions and cost effectiveness for NO_X and PM based on adjusting the annual costs, the NO_X control efficiency for SCR and the baseline PM emissions as discussed above.

TABLE 7—FCPP COST EFFECTIVENESS FOR NO_X BASED ON EPA REVISIONS

	LNB/LNB + OFA	SCR	SCR + LNB	SCR + LNB + OFA
Tons of NO_X Reduced per Year (tpy)				
Unit 1	2,478	4,417	5,097	5,097
Unit 2	1,524	3,716	4,210	4,210
Unit 3	2,563	4,652	5,224	5,224
Unit 4	3,275	9,171	10,060	10,060
Unit 5	3,284	9,195	10,086	10,086
Cost Effectiveness of Controls ($/ton)				
Unit 1	249	3,758	3,284	3,298
Unit 2	404	4,803	4,314	4,329
Unit 3	275	3,646	3,314	3,298
Unit 4	699	4,341	3,957	4,167
Unit 5	697	4,330	3,947	4,156

TABLE 8—FCPP COST EFFECTIVENESS FOR PM BASED ON EPA REVISIONS

	Upstream ESP	Upstream baghouse	Wet metal ESP	Wet membrane ESP
Tons of PM Reduced per Year (tpy)				
Unit 1	92	92	92	92
Unit 2	123	123	123	123
Unit 3	375	375	375	375
Cost Effectiveness of Controls ($/ton)				
Unit 1	60,691	82,334	52,378	38,074
Unit 2	55,556	74,143	39,968	29,054
Unit 3	16,074	23,867	23,867	10,808

[9] White Paper: Selective Catalytic Reduction (SCR) Control of NO_X Emissions from Fossil Fuel-Fired Electric Power Plants, Prepared by Institute of Clean Air Companies Inc., May 2009.

[10] See *http://www.azdeq.gov/environ/air/permits/download/pastmonth.pdf.*

The National Park Service (NPS) calculated the cost effectiveness of SCR using only the estimates and allowed categories of costs from EPA's Air Pollution Control Costs Manual. The NPS costs of compliance and cost effectiveness are shown in Table 9. NPS assumed post-SCR NO_X emissions of 0.06 lb/MMBtu. The capital and annual costs of SCR the NPS estimated using the EPA Control Cost Manual are considerably lower than those estimated by APS.

TABLE 9—NPS'S ESTIMATED SCR COSTS OF COMPLIANCE FOR FCPP

	Total capital cost	Total annual cost	Cost effectiveness (ton)
Unit 1	$18,508,764	$2,983,004	$1,558
Unit 2	18,508,764	3,052,010	1,469
Unit 3	22,187,577	3,497,117	1,684
Unit 4	52,788,968	9,838,997	1,185
Unit 5	52,788,968	9,213,942	1,357

In Tables 10 and 11, EPA has calculated the expected increase in electricity generation costs to be borne by consumers in terms of dollars per kilowatt hour ($/kWh), assuming 85% capacity. The calculation is based on EPA's annual cost estimates in Tables 5 and 6. DOE provides information on the average cost of electricity by state in a given year.[11] In 2009, the average cost of electricity in Arizona for residential consumers was $0.0994/kWh, which was below the U.S. average ($0.1128/kWh) and the continental U.S. maximum of $0.1993/kWh in Connecticut.

TABLE 10—INCREASE IN ELECTRICITY COSTS FROM NO_X CONTROLS AT FCPP

	LNB/LNB + OFA kWh	SCR kWh	SCR + LNB kWh	SCR + LNB + OFA kWh
Unit 1	$0.001	$0.015	$0.015	$0.015
Unit 2	0.001	0.016	0.016	0.016
Unit 3	0.001	0.011	0.012	0.012
Unit 4	0.001	0.009	0.009	0.009
Unit 5	0.001	0.009	0.009	0.009

TABLE 11—INCREASE IN ELECTRICITY COSTS FROM PM CONTROLS AT FCPP

	Upstream ESP kWh	Upstream baghouse kWh	Wet metal ESP kWh	Wet membrane ESP kWh
Unit 1	$0.005	$0.007	$0.004	$0.003
Unit 2	0.006	0.008	0.004	0.003
Unit 3	0.004	0.006	0.006	0.003

EPA requests comments on the data used to estimate the cost of compliance for the different levels of control for NO_X and PM for FCPP.

2. NGS

a. Cost of Compliance

The cost estimates provided by SRP (updated in the 2008 submissions to EPA) are included in Table 12 for different control options for NO_X. The NO_X control options included in Table 12 are (1) LNB plus Separated Overfire Air (SOFA) on all three units, (2) SCR on Units 1 and 3, LNB + SOFA on Unit 2, and (3) SCR + LNB + SOFA on all three units.

TABLE 12—NGS COSTS OF COMPLIANCE FOR NO_X BASED ON SRP ANALYSIS

	LNB + SOFA (All units)	SCR + LNB + SOFA (Units 1 & 3); LNB + SOFA (Unit 2)	SCR + LNB + SOFA (All units)
Total Capital Investment			
Unit 1	$14,000,000	$212,000,000	$212,000,000
Unit 2	14,000,000	14,000,000	281,000,000
Unit 3	14,000,000	212,000,000	212,000,000

[11] *http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_b.html*

TABLE 12—NGS COSTS OF COMPLIANCE FOR NO_X BASED ON SRP ANALYSIS—Continued

	LNB + SOFA (All units)	SCR + LNB + SOFA (Units 1 & 3); LNB + SOFA (Unit 2)	SCR + LNB + SOFA (All units)
Total Annual Cost			
Unit 1	1,622,000	28,951,500	28,951,500
Unit 2	1,622,000	36,945,000	36,945,000
Unit 3	1,622,000	28,951,500	28,951,500

The higher retrofit cost of SCR on Unit 2 compared to Units 1 and 3 is a result of the physical layout of the coal conveyor and its supports in relation to Unit 2. Because of limited access for construction cranes and equipment, and to make room for the SCR and fans by demolishing the remainder of the old Unit 2 chimney, costs for the Unit 2 retrofit are anticipated to be higher than for Units 1 and 3.[12]

b. Cost Effectiveness

In determining the cost effectiveness of controls, SRP estimated NO_X emissions reductions using baseline emission rates of: 0.49 lb/MMBtu for Unit 1; 0.45 lb/MMBtu for Unit 2; 0.46 lb/MMBtu for Unit 3. For the various control options, SRP estimated emissions reductions from: LNB + SOFA of 47–51% to achieve 0.24 lb/MMBtu; and from SCR of 82–84% to achieve 0.08 lb/MMBtu.

Table 13 lists the reduction in NO_X emissions and cost effectiveness estimated by SRP for the three control scenarios listed in Table 12.

TABLE 13—SRP EMISSIONS REDUCTIONS AND COST EFFECTIVENESS FOR NO_X

	LNB + SOFA (All units)	SCR + LNB + SOFA (Units 1 & 3); LNB + SOFA (Unit 2)	SCR + LNB + SOFA (All units)
NO_X Emissions Reductions (tpy)			
Unit 1	9,631	15,794	15,794
Unit 2	8,667	8,667	15,271
Unit 3	8,824	15,241	15,241
Cost Effectiveness ($/ton)			
Unit 1	168	1,833	1,833
Unit 2	187	187	2,419
Unit 3	184	1,900	1,900

Appendix Y of the BART Guidelines states that average cost effectiveness should be based on the annualized cost and the difference between baseline annual emissions and annual emissions with the control technology. In calculating the cost effectiveness, it appears SRP used the same 24-hour average actual emission rate from the highest emitting day used for its modeling inputs, rather than an annual average rate. Therefore, EPA has revised SRP's estimated NO_X emissions reductions by starting with baseline emission rates for NO_X averaged over 2004–2006 of: 0.35 lb/MMBtu for Unit 1; 0.37 lb/MMBtu for Unit 2; 0.31 lb/MMBtu for Unit 3. The revised emission reductions and cost effectiveness estimates are provided in Table 14.

TABLE 14—EPA EMISSIONS REDUCTIONS AND COST EFFECTIVENESS FOR NO_X

	LNB + SOFA (All units)	SCR + LNB + SOFA (Units 1 & 3); LNB + SOFA (Unit 2)	SCR + LNB + SOFA (All units)
NO_X Emissions Reductions (tpy)			
Unit 1	3,658	9,643	9,643
Unit 2	4,208	4,208	9,888
Unit 3	2,284	8,158	8,158
Cost Effectiveness ($/ton)			
Unit 1	443	3,002	3,002
Unit 2	385	385	3,736

[12] See July 29, 2008 Letter from Kevin Wanttaja (SRP) to Deborah Jordan (EPA) and its attachment: July 25, 2008 Final Report for SCR and SNCR Cost Study, prepared by Sargent and Lundy.

TABLE 14—EPA EMISSIONS REDUCTIONS AND COST EFFECTIVENESS FOR NO_X—Continued

	LNB + SOFA (All units)	SCR + LNB + SOFA (Units 1 & 3); LNB + SOFA (Unit 2)	SCR + LNB + SOFA (All units)
Unit 3	710	3,549	3,549

The NPS calculated the cost effectiveness of SCR + LNB + SOFA using only the estimates and allowed categories of costs from EPA's Air Pollution Control Costs Manual. The NPS costs of compliance and cost effectiveness are shown in Table 15. NPS assumed post-SCR NO_X emissions of 0.05 lb/MMBtu. NPS accounts for the higher retrofit costs associated with Unit 2 by applying a larger retrofit factor associated with physically difficult retrofits on Unit 2 compared to Units 1 and 3. Note that the capital and annual costs of SCR estimated using the EPA Control Cost Manual are considerably lower than those estimated by SRP.

TABLE 15—NPS COSTS OF CONTROLS AND COST EFFECTIVENESS FOR SCR

	Total capital cost	Total annual cost	Cost effectiveness (ton)
Unit 1	$71,983,100	$12,065,299	$1,059
Unit 2	66,138,162	14,589,766	1,528
Unit 3	68,642,323	11,870,003	1,317

EPA calculated the expected increase in electricity generation costs to consumers in $/kWh, assuming 85% capacity in Table 16.

TABLE 16—INCREASE IN ELECTRICITY COSTS FROM NO_X CONTROLS AT NGS

	LNB + SOFA (All Units) kWh	SCR + LNB + SOFA (Units 1&3); LNB + SOFA (Unit 2) kWh	SCR + LNB + SOFA (All Units) kWh
Unit 1	$0.0003	$0.006	$0.006
Unit 2	0.0003	0.0003	0.007
Unit 3	0.0003	0.006	0.006

In addition to the three NO_X control scenarios, EPA considered another SCR control option that was not addressed by SRP. Based on EPA's understanding of the location of the coal-feed line and the physical layout of Unit 2, EPA is requesting comment on the application of half an SCR to Unit 2. As configured, the flue gas from Unit 2 is split in half with each half containing its own separate hot-side ESP and FGD. Because the flue gas is already split, and because the coal-feed line impedes only one side of the Unit 2 split, SCR may be applied to half of Unit 2 so that the difficult retrofit associated with the relocation of the coal-feed line can be avoided. EPA estimates that the application of half-SCR on Unit 2 would require a total capital investment of $106 million, a total annual cost of $14.5 million, result in NO_X reductions of over 7000 tpy (based on control to 0.14 lb/MMBtu) with a cost effectiveness of $2000/ton and an increased electricity generation cost of $0.003/kWh.

In the November 2007 BART Analysis, SRP states that PM emissions controlled by hot-side ESPs in combination with wet scrubbers effectively limited PM emissions to less than 0.03 lb/MMBtu and did not include a BART analysis for further retrofit controls for PM_{10}. In a letter dated December 12, 2008, NGS proposed a BART emission limit for PM of 0.05 lb/MMBtu. No additional discussions of modeling or other analyses for PM control at NGS are included in this ANPR.

EPA requests comment on the data provided above to estimate the costs of compliance for BART controls at NGS.

B. Factor 5: Degree of Visibility Improvement

1. FCPP

a. Visibility Modeling Scenarios

APS's contractor, AECOM, conducted visibility modeling using CALPUFF [13] based on a number of selected inputs. APS used its modeling results to estimate anticipated visibility improvement from the four different control technology options at the mandatory Class I Federal areas within a 300 km radius.

EPA disagrees with and is requesting comment on a number of the inputs APS used for modeling. EPA has selected alternative inputs that we have determined are more representative. We have also modeled the resulting visibility improvement at the Class I areas based on our revised inputs. EPA is specifically requesting comment on EPA's and APS's selection of inputs. EPA's modeled results, also using CALPUFF, are presented below in Tables 17–21. The modeling scenarios are:

[13] CALPUFF is the model that is recommended for use in predicting visibility impact under the Regional Haze Guidelines. 40 CFR Part 51, App. Y, III.A.3 (''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. [note omitted]'').

A. Baseline Visibility Impact (modeled by APS and EPA)
B. Wet ESP for PM Control on Units 1–3 (modeled by APS and EPA)
C1. LNB + OFA for NO_X on Units 1–5 (modeled by APS)
C2. LNB for NO_X on Units 1 and 2 and LNB + OFA on Units 3–5 (modeled by EPA)
D. SCR for NO_X on Units 3–5 (modeled by EPA)
E1. SCR + LNB + OFA for NO_X on Units 1–5 (modeled by APS)
E2. SCR for NO_X on Units 1–5 (modeled by EPA)

APS and EPA modeled baseline and control scenarios using meteorological data from 2001–2003. The baseline scenario uses heat input and pollutant emission rates based on the 24-hour average actual emission rate from the highest emitting day of the meteorological period. The modeling scenarios listed above in C1/C2 and E1/E2 are based on the application of the same, or similar, control technologies but are listed as distinct modeling scenarios because EPA used different emission inputs than APS.

b. EPA Modifications to Emission Rate Inputs

The Appendix Y BART Guidelines state that baseline heat input and pollutant emission rates should be based on the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled. Although the modeling period for the BART analysis submitted by APS is 2001–2003, APS used heat input, NO_X, SO_2, and PM emission rates from 2002–2006. Based on our review of the 2001–2003 emissions data that APS reported to the EPA Clean Air Markets Division (CAMD), we have determined that the heat input and baseline NO_X emission rates inputs were generally appropriate, except that several of the highest emitting days for NO_X and heat input occurred in 2001. Therefore, EPA revised the highest heat input rate for Units 1, 3, and 5 based on the 2001–2003 meteorological period. For NO_X emissions, the highest emitting days for Units 1,2, 3, and 5 occurred in 2001 (over the 2001–2003 period), therefore, we also revised the baseline NO_X emission rate for those units. Data from CAMD for Unit 2 and 4 generally agreed with emission inputs used by APS. For SO_2 emissions, because the SO_2 control efficiency for Units 4 and 5 recently increased to 88%, EPA considers it more appropriate to rely on a more recent period (2006–2007) for SO_2 emissions for Units 4 and 5, rather than using SO_2 data from the 2001–2003 meteorological period.

CALPUFF modeling requires additional inputs, including SO_4, representing condensable inorganic PM and fine and coarse filterable PM. For SO_4, APS estimated that the condensable inorganic PM was entirely represented by sulfuric acid (H_2SO_4) formed during the combustion process (Scenarios A—C), or from the combustion process together with reactions on the SCR catalyst (Scenarios D and E). APS and EPA both relied on the H_2SO_4 calculation methodology provided by the Electric Power Research Institute (''EPRI''). [14] The EPRI method relies on characterization of various sources and sinks of H_2SO_4 in the boiler and downstream components, such as the air preheater, and particulate matter (PM) and SO_2 control devices. For the baseline and non-SCR emissions scenarios (Scenarios A–C), the main difference between APS's and EPA's calculations for H_2SO_4 arises from the assumed loss of H_2SO_4 in the air preheater. APS used a penetration factor [15] of 0.9 whereas EPA used a penetration factor of 0.49, which is consistent with the 2008 EPRI guidelines.

Because CAMD data is not available for PM, we relied on filterable PM emissions used in APS's revised modeling analysis (Supplemental submitted November 2008), based on the maximum of six stack test results from the 2002–2006 period for each unit. APS additionally provided the stack test results in a spreadsheet for each unit over 2002–2006. Although APS reported using the worst-case stack test values in their Supplemental Modeling Report, the lb/MMBtu PM values in Table 5–2 do not match the highest stack test results in the APS's spreadsheet. Therefore, EPA revised the filterable PM values for Units 1–3. We then applied values from AP–42 that estimate for a dry bottom boiler with scrubber (Units 1–3), 71% of filterable PM is PM_{10}, and 51% of filterable PM is fine PM_{10} (*i.e.,* $PM_{2.5}$), thus 20% of filterable PM is coarse PM_{10}, *i.e.,* 71%–51%. For a dry bottom boiler with a baghouse (Units 4 and 5), AP–42 estimates that 92% of filterable PM is PM_{10}, and 53% of filterable PM is fine PM_{10} (*i.e.,* $PM_{2.5}$), thus 39% of filterable PM is coarse PM_{10}, *i.e.,* 92%–53%. APS also estimated elemental carbon (EC) to be 3.7% of the $PM_{2.5}$, based on Table 6 of a 2002 draft report prepared for EPA.[16]

In addition to the estimates for PM fine described above, EPA additionally revised the modeling inputs for PM fine to include emissions of hydrogen chloride (HCl) and hydrogen fluoride (HF). AP–42 (1.1 Bituminous and Subbituminous Coal Combustion) provides a single emission factor each for HCl and HF from all coal and boiler types. APS assumed H_2SO_4 to be the only contributor to condensable inorganic PM, and the NPS raised concerns about the exclusion of HCl and HF and recommended these two compounds be factored into the CPM–IOR (SO_4) modeling input. Method 202 for measuring condensable PM does not capture HCl and HF, therefore, EPA added these emissions to PM fine rather than SO_4.

HCl and HF emission factors in AP–42 (Table 1.1–15) are based on a lb/ton coal basis (1.2 lbs HCl per ton of coal and 0.15 lb HF per ton of coal, which converts to 0.016 lb HCl/mmbtu and 0.007 lb HF/mmbtu using 10496 Btu/lb coal). Footnote (a) to Table 1.1–15 in AP–42 states that these factors apply to both controlled and uncontrolled sources. The HCl and HF emission factors refer to a 1985 report on HCl and HF prepared for the NAPAP inventory.[17] This 1985 report shows that the uncontrolled and controlled emission factors for HCl and HF were considered to be the same only because wet scrubbers and FGD systems, which are the only controls used on boilers that have a significant effect on HCl and HF removal, were (at the time) used to control only a small percentage of coal burned in utility boilers (see footnote (a) from Tables 3–6 and 3–7 from the 1985 report). Given that 2 units at FCPP use wet FGD and 3 units use venturi scrubbers for SO_2 control, EPA did not apply the AP–42 emission factor ''as is'' to FCPP. Furthermore, given that the chlorine content of the coal used by FCPP is much lower than coal from other parts of the U.S., we scaled the HCl emission factor (based on 46 sites from several parts of the country [18]) for subbituminous coal to account for the low Cl content of FCPP coal compared to average Cl content of U.S. coal.

[14] *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants—Technical Update,* Electric Power Research Institute (EPRI), Palo Alto, CA, 2008. EPRI Product ID: 1016384.

[15] We use penetration factor as 1-control factor, such that a penetration factor of 0.9 means 90% of the sulfuric acid penetrates through the control equipment.

[16] Battye, W, and Boyer, K. *Catalog of Global Emissi113on Inventories and Emission Inventory Tools for Black Carbon.* EPA Contract No. 68–D–98–046, 2002.

[17] *Hydrogen Chloride and Hydrogen Fluoride Emission Factors for the NAPAP Inventory,* EPA–600/7–85–041, U.S. Environmental Protection Agency, October 1985.

[18] See Reference 1 of Table A–1 from the 1985 EPA report.

From the emission factor of 1.9 lb HCl/ton, EPA scaled the emission factor to 0.13 lb HCl/ton coal. Table 3–2 of the 1985 report shows that average Cl content of coal by coal type ranges from 63–1064 ppm (by weight) with lignite and eastern bituminous coals contributing the low and high values, respectively. Table 3–3 shows that average Cl content of coal ranges from 20–1900 ppm (by weight), with Montana coal and Illinois coal contributing the low and high values, respectively. The average bituminous coal Cl content from the values reported in Table 3–2 is 736 ppm. From chlorine coal content data collected for the Clean Air Mercury Rule,[19] FCPP coal was determined to have 50 ppm Cl. Therefore, we scaled the HCl emission factor of 1.9 by the Cl content ratio of FCPP to bituminous US coal (50/736) yielding an emission factor of 0.13 lb HCl/ton coal.

For the fluorine content of coal, Tables 3–2 and 3–3 from the 1985 report show that average F content ranges from 28–141 ppm depending on coal type (lignite and eastern bituminous, respectively), and from 45–124 depending on the region in the U.S. (Northern Great Plains and Gulf Province, respectively). Based on trace element data reported in the U.S. Coal Quality Database,[20] coal burned by FCPP (from the Navajo Mine) has an average F content of 80 ppm.[21] We scaled the HF emission factor of 0.23 lb/ton by the F content ratio of FCPP coal to total US (80/102), resulting in an FCPP emission factor for HF of 0.18 lb HF/ton coal.

Using the scaled emission factors of 0.13 lb HCl/ton coal and 0.18 lb HF/ton coal, EPA accounted for additional loss of HCl and HF from the use of flue gas desulfurization (FGD) or venturi scrubbers. Page 19 of the 1985 EPA report describes that wet scrubbers are expected to provide approximately 80% control of HCl and HF from coal-fired utility boilers, and removal of HCl from flue gases with FGD systems is very high (with sodium bicarbonate systems providing 95% control), but little data are available to quantify the HF removal efficiency of FGD systems. We assumed the FGD and venturi scrubbers provided 80% control of HCl and HF. Thus, our HCl and HF emission factors for FCPP are 0.015 lb HCl/MMBtu and 0.0020 lb HF/MMBtu. These HCl and HF emissions were applied as inputs to PM fine for all modeling scenarios.

TABLE 17—APS AND EPA BASELINE EMISSION RATES

[Scenario A]

	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
APS Modeling Inputs for Baseline Case (all units in lb/hr)					
SO_2	464.17	615.12	995.26	2,026.10	2,130.76
SO_4	3.35	3.78	4.65	1.03	1.03
NO_X	1,841.37	1,567.66	1,926.23	5,015.98	4,444.04
SOA	8.35	9.41	11.58	32.00	32.00
PM fine	30.74	47.87	52.90	100.93	48.00
PM coarse	12.52	19.49	21.54	77.12	36.67
EC	1.18	1.84	2.03	3.88	1.84
EPA Modeling Inputs for Baseline Case (all units in lb/hr)					
SO_2	522.54	615.12	1,042.09	2,026.10	2,131.85
SO_4	2.06	2.06	2.65	0.51	0.51
NO_X	2,020.14	1,599.47	1,970.80	5,015.98	4,508.56
SOA	9.40	9.41	12.13	32.00	32.20
PM fine	46.29	65.99	70.18	128.93	76.20
PM coarse	15.50	23.52	24.26	77.12	36.69
EC	1.46	2.22	2.29	3.88	1.85

TABLE 18—APS AND EPA EMISSION FOR PM CONTROL ON UNITS 1–3

[Scenario B]

	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
APS Modeling Inputs for Baseline Case (all units in lb/hr)					
SO_2	464.17	615.12	995.26	2,026.10	2,130.76
SO_4	0.34	0.38	0.47	1.03	1.03
NO_X	1,841.37	1,567.66	1,926.23	5,015.98	4,444.04
SOA	8.35	9.41	11.58	32.00	32.00
PM fine	15.34	20.39	22.54	100.93	48.00
PM coarse	11.72	15.58	17.22	77.12	36.67
EC	0.59	0.78	0.87	3.88	1.84
EPA Modeling Inputs for Baseline Case (all units in lb/hr)					
SO_2	522.54	615.12	1,042.09	2,026.10	2,131.85
SO_4	0.21	0.21	0.27	0.51	0.51
NO_X	2,020.14	1,599.47	1,970.80	5,015.98	4,508.56
SOA	9.40	9.41	12.13	32.00	32.20

[19] Electric Utility Mercury Information Collection Request (OMB Control Number 2060–0396): *http://www.epa.gov/ttn/atw/combust/utiltox/utoxpg.html#DA2.*

[20] *http://energy.er.usgs.gov/coalqual.htm#submit.*

[21] Based on samples D176206 and D202211.

TABLE 18—APS AND EPA EMISSION FOR PM CONTROL ON UNITS 1–3—Continued

[Scenario B]

	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
PM fine	25.49	28.63	34.21	128.93	76.20
PM coarse	13.19	15.58	18.03	77.12	36.69
EC	0.66	0.78	0.91	3.88	1.85

TABLE 19—APS AND EPA EMISSION FOR PM CONTROL ON UNITS 1–3

[Scenario C]

	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
APS Modeling Inputs for LNB + OFA (Scenario C1) (in lb/hr)					
SO_2	464.17	615.12	995.26	2,026.10	2,130.76
SO_4	3.35	3.78	4.65	1.03	1.03
NO_X	1,010.91	1,051.90	1,078.69	3,561.35	3,155.27
SOA	8.35	9.41	11.58	32.00	32.00
PM fine	30.74	47.87	52.90	100.93	48.00
PM coarse	12.52	19.49	21.54	77.12	36.67
EC	1.18	1.84	2.03	3.88	1.84
EPA Modeling Inputs for LNB/OFA (Scenario C2) (in lb/hr)					
SO_2	522.54	615.12	1,042.09	2,026.10	2,131.85
SO_4	2.06	2.06	2.65	0.51	0.51
NO_X	1,109.06	1,073.25	1,103.65	3,561.35	3,201.08
SOA	9.40	9.41	12.13	32.00	32.20
PM fine	46.29	65.99	70.18	128.93	76.20
PM coarse	15.50	23.52	24.26	77.12	36.69
EC	1.46	2.22	2.29	3.88	1.85

EPA also disagrees with APS's evaluation of sulfuric acid emissions. Sulfuric acid emissions are estimated to increase as a result of operating an SCR due to additional oxidation of SO_2 to SO_3 on the SCR catalyst. APS used a 1% conversion rate from the SCR catalyst. Yet a Prevention of Significant Deterioration (PSD) permit issued June 2, 2009, to Coronado Generating Station by the ADEQ [22] required the use of an ultra-low conversion catalyst (0.5% conversion) as Best Available Control Technology (BACT). EPA has determined that APS could also use an ultra-low conversion catalyst. Therefore, in our calculation of H_2SO_4 emissions from the addition of the SCR, we accounted for a 0.5% conversion of SO_2 to SO_3.

For emissions of ammonia (NH_3) resulting from SCR, EPA followed the calculation methodology APS used in its supplemental modeling analysis for FCPP (dated November 2008).

TABLE 20—EPA EMISSIONS FOR SCR ON UNITS 3–5

[Scenario D]

	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
EPA Modeling Inputs for SCR on Units 3–5, No Control Units 1 and 2 (in lb/hr)					
SO_2	522.54	615.12	1,042.09	2,026.10	2,131.85
SO_4	2.06	2.06	12.52	2.52	2.54
NO_X	2,020.14	1,599.47	472.99	1,203.84	1,082.05
SOA	9.40	9.41	12.13	32.00	32.20
PM fine	46.29	65.99	70.18	128.93	76.20
PM coarse	15.50	23.52	24.26	77.12	36.69
EC	1.46	2.22	2.29	3.88	1.85

TABLE 21—APS AND EPA EMISSIONS FOR SCR ON UNITS 1–5

[Scenario E]

	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
APS Modeling Inputs for SCR + LNB + OFA (Scenario E1) (in lb/hr)					
SO_2	464.17	615.12	995.26	2,026.10	2,130.76

[22] See *http://www.azdeq.gov/environ/air/permits/download/pastmonth.pdf.*

TABLE 21—APS AND EPA EMISSIONS FOR SCR ON UNITS 1–5—Continued

[Scenario E]

	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
SO_4	30.71	34.61	42.61	9.53	9.58
NO_X	147.31	141.09	192.62	601.92	533.29
SOA	8.35	9.41	11.58	32.00	32.00
PM fine	30.74	47.87	52.90	100.93	48.00
PM coarse	12.52	19.49	21.54	77.12	36.67
EC	1.18	1.84	2.03	3.88	1.84
EPA Modeling Inputs for SCR (Scenario E2) (in lb/hr)					
SO_2	522.54	615.12	1,042.09	2,026.10	2,131.85
SO_4	9.70	9.71	12.52	2.52	2.54
NO_X	484.83	383.87	472.99	1,203.84	1,082.05
SOA	9.40	9.41	12.13	32.00	32.20
PM fine	46.29	65.99	70.18	128.93	76.20
PM coarse	15.50	23.52	24.26	77.12	36.69
EC	1.46	2.22	2.29	3.88	1.85

c. Ammonia Background

In addition to the different CALPUFF emission rates described above, EPA additionally revised some post-processor settings from those originally used by APS. The USFS indicated that the ammonia background concentrations modeled by APS were underestimated compared to observed concentrations.[23] EPA agrees and has used a similar back-calculation methodology to the one referenced by the USFS for estimating ammonia background values.

Ammonia is important because it is a precursor to particulate ammonium sulfate and ammonium nitrate which degrades visibility. It is present in the air from both natural and anthropogenic sources. The latter may include ammonia slip from the use of ammonia in SCR and SNCR technologies to control NO_X emissions.

In our modeling input for ammonia, EPA assumed that the remaining ammonia in the flue gas following SCR reacts to form ammonium sulfate or ammonium bisulfate before exiting the stack. This particulate ammonium is represented in the modeling as sulfate (SO_4) emissions. Thus, EPA addressed ammonia solely as a background concentration.

Very little monitored ammonia data is available. The default recommended ammonia background value for arid regions is 1 ppb, as described in the *IWAQM Phase 2* document.[24] Alternative levels may be used if supported by data. To address concerns expressed by APS in their January 2008 BART modeling protocol (p. 4–1) that CALPUFF over-predicts ammonium nitrate in winter, EPA estimated ammonia background for all Class I areas (except Mesa Verde National Park, see below) by back-calculating from measurements at monitors in the areas run by the IMPROVE program.[25] IMPROVE monitors do not measure ammonia directly; rather, they measure particulate sulfate and nitrate. In the atmosphere, particulate sulfate and nitrate are essentially all in the form of ammonium sulfate and ammonium nitrate, respectively. Applying their chemical formulas, EPA estimated a lower bound on the amount of ammonia that must have been present to combine with gaseous sulfate and nitrate in order to form the measured particulate sulfate and nitrate.

EPA performed this back-calculation using 2005–2007 data for all 14 IMPROVE monitors at Class I areas in the modeling domains. For each monitor, EPA used the maximum calculated value for each calendar month to represent the month. Then, for each month, EPA averaged over all monitors, resulting in a single value for each of the 12 calendar months. For the months of May and July, this back-calculation resulted in a somewhat lower value than the *IWAQM* default of 1 ppb which was also used by APS; for these months EPA used 1 ppb. The back-calculation results ranged from 0.7 ppb in the winter to 1 ppb in summer, except the value of 1.3 ppb in June.

Ammonia background concentrations for Mesa Verde National Park were derived from measured ammonia concentrations in the Four Corners area, as described in Sather *et al.*, (2008).[26] Monitored data was available within park, but because particulate formation happens within a pollutant plume as it travels, rather than instantaneously at the Class I area, EPA also examined data at locations outside the park itself. Monitored 3-week average ammonia at the Substation site, some 30 miles south of Mesa Verde, were as high as 3.5 ppb, though generally levels were under 1.5 ppb. Maximum values in Mesa Verde were 0.6 ppb, whereas other sites' maxima ranged from 1 to 3 ppb, but generally values were less than 2 ppb. EPA used values estimated from Figure 5 of Sather *et al.*, (2008), in the mid-range of the various stations plotted. The results ranged from 1.0 ppb in winter to 1.5 ppb in summer. See Table 22.

TABLE 22—AMMONIA BACKGROUND CONCENTRATION IN PPB (POSTUTIL PARAMETER BCKNH3) FOR FCPP

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
IWAQM default	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

[23] Letter from Rick Cables (Forest Service R2 Regional Forester) and Corbin Newman (Forest Service R3 Regional Forester) to Deborah Jordan (EPA Region 9 Air Division Director) dated March 17, 2009.

[24] Interagency Workgroup On Air Quality Modeling (IWAQM) Phase 2 Summary Report And Recommendations For Modeling Long Range Transport Impacts (EPA–454/R–98–019), EPA OAQPS, December 1998, *http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf*.

[25] http://vista.cira.colostate.edu/improve/.

[26] Mark E. Sather *et al.*, 2008. ''Baseline ambient gaseous ammonia concentrations in the Four Corners area and eastern Oklahoma, USA''. Journal of Environmental Monitoring, 2008, 10, 1319–1325, DOI: 10.1039/b807984f.

TABLE 22—AMMONIA BACKGROUND CONCENTRATION IN PPB (POSTUTIL PARAMETER BCKNH3) FOR FCPP—Continued

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
APS values	0.2	0.2	0.5	0.5	1.0	1.0	1.0	1.0	1.0	0.5	0.5	0.2
EPA values	0.8	0.7	0.7	1.0	1.0	1.3	1.0	1.0	1.0	1.0	1.0	0.9
EPA values for Mesa Verde	1.0	1.0	1.3	1.3	1.3	1.3	1.5	1.5	1.5	1.5	1.3	1.0

d. Natural Background

The BART determination guidelines recommend that impacts of sources should be estimated in deciviews relative to natural background. CALPOST, a CALPUFF post-processor, uses background concentrations of various pollutants to calculate the natural background visibility impact. EPA used background concentrations from Table 2–1 of ''Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule.'' [27] Although the concentration for each pollutant is a single value for the year, this method allows for monthly variation in its visibility impact, which changes with relative humidity. The resulting deciviews differ by roughly 1% from those resulting from the method originally used by APS.

TABLE 23—NATURAL BACKGROUND CONCENTRATIONS FOR FCPP AND NGS

CALPOST parameter	Pollutant	Concentration (µg/m^3)
BKSO4	ammonium sulfate	0.12
BKNO3	ammonium nitrate	0.10
BKPMC	coarse particulates	3.00
BKOC	organic carbon	0.47
BKSOIL	soil	0.50
BKEC	elemental carbon	0.02

e. Visibility Modeling Results

To assess results from the CALPUFF model and post-processing steps, EPA used a least-squares regression analysis of all visibility modeling output from the 2001–2003 modeling period to determine the percent improvement in visibility (measured in deciviews) compared to the baseline resulting from the application of control technologies. Table 24 shows EPA's modeled predicted visibility improvements at the 16 Class I areas within a 300 km radius of FCPP.

APS presented visibility improvement by comparing the 98th percentile (8th highest) of the daily maximum deciview (dv) values from CALPUFF per Class I area, averaged over 2001–2003. As outlined in the 1999 Regional Haze rule (64 FR 35725, July 1, 1999), a one deciview change in haziness is a small but noticeable change in haziness under most circumstances when viewing scenes in a Class I area. Table 25 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area for each year, averaged over 2001–2003, determined for FCPP by APS. Table 26 presents the visibility impacts of the 98th percentile of daily maxima from 2001–2003 for each Class I area determined by EPA.[28]

TABLE 24—PERCENT IMPROVEMENT IN DECIVIEW IMPACTS FROM EPA MODELING AT EACH CLASS I AREA FROM PM AND NO_X CONTROLS AT FCPP

	Scenario B (Wet ESP) (%)	Scenario C2 (LNB) (%)	Scenario D (SCR 3–5) (%)	Scenario E2 (SCR 1–5) (%)
Arches	0.4	17	31	49
Bandolier	0.5	20	37	52
Black Canyon	0.3	22	39	55
Canyonlands	0.4	15	28	45
Capitol Reef	0.3	17	30	46
Grand Canyon	0.4	19	33	50
Great Sand Dunes	0.4	24	44	42
La Garita	0.4	24	43	42
Maroon Bells	0.4	25	43	59
Mesa Verde	0.6	14	27	42
Pecos	0.5	21	39	53
Petrified Forest	0.4	20	35	51
San Pedro	0.6	18	32	47
West Elk	0.3	24	42	58
Weminuche	0.5	22	50	55
Wheeler Peak	0.5	22	40	55

[27] U.S. Environmental Protection Agency, EPA–454/B–03–005, September 2003, on web page *http://www.epa.gov/ttn/oarpg/t1pgm.html,* with direct link *http://www.epa.gov/ttn/oarpg/t1/memoranda/rh_envcurhr_gd.pdf.*

[28] EPA did not average the 98th percentiles from each year as did APS, rather EPA used the 98th percentile from all three years taken together. This does not significantly impact the overall results.

TABLE 25—IMPACTS OF FCPP ON VISIBILITY (98TH PERCENTILE OF DAILY MAXIMUM DV) AT SIXTEEN CLASS I AREAS AS MODELED BY APS

	Baseline	Visibility impact (dv) after applying:		
		Wet ESP (B)	LNB (C1)	SCR (E1)
Arches	1.98	1.96	1.74	1.23
Bandolier	1.71	1.70	1.57	1.12
Black Canyon	1.44	1.43	1.21	0.75
Canyonlands	2.25	2.23	2.06	1.67
Capitol Reef	1.74	1.73	1.53	1.15
Grand Canyon	1.07	1.07	0.95	0.66
Great Sand Dunes	1.02	1.02	1.02	0.62
La Garita	1.36	1.36	1.08	0.58
Maroon Bells	1	0.81	0.66	0.35
Mesa Verde	3.17	3.14	3.01	2.73
Pecos	1.55	1.54	1.31	0.88
Petrified Forest	1.21	1.20	1.05	0.68
San Pedro	2.21	2.18	2.04	1.51
West Elk	1.22	1.21	1.03	0.56
Weminuche	1.90	1.68	1.66	0.94
Wheeler Peak	1.20	1.19	0.97	0.64
Sum of Class I areas	26.03	25.45	22.89	16.07

TABLE 26—IMPACTS OF FCPP ON VISIBILITY (98TH PERCENTILE DV) ON SIXTEEN CLASS I AREAS AS MODELED BY EPA

	Baseline	Visibility Impact (dv) after applying:			
		Wet ESP	LNB (C2)	SCR(D)	SCR (E2)
Arches	4.03	4.02	3.24	2.55	1.83
Bandolier	2.91	2.90	2.25	1.81	1.38
Black Canyon	2.36	2.36	1.89	1.44	1.01
Canyonlands	4.89	4.87	4.21	3.76	2.66
Capitol Reef	3.21	3.20	2.44	1.87	1.48
Grand Canyon	1.63	1.63	1.31	0.96	0.81
Great Sand Dunes	1.21	1.20	0.91	0.67	0.54
La Garita	1.71	1.71	1.28	1.05	0.73
Maroon Bells	1.04	1.04	0.77	0.57	0.43
Mesa Verde	6.48	6.45	5.47	4.90	3.89
Pecos	2.11	2.10	1.65	1.34	1.06
Petrified Forest	1.51	1.51	1.14	0.97	0.81
San Pedro	3.81	3.80	3.13	2.53	2.01
West Elk	1.86	1.86	1.41	1.06	0.75
Weminuche	2.79	2.77	2.16	1.58	1.17
Wheeler Peak	1.50	1.50	1.17	0.93	0.74
Sum of Class I areas	43.05	42.90	34.43	27.99	21.29

EPA used higher values for ammonia background concentration than APS, which resulted in higher modeled visibility impacts of FCPP and larger percent visibility improvement of controls compared to APS modeling. Although the different inputs used by EPA changed the absolute deciview values, it did not change the relative ranking of the controls in terms of deciview benefit. The different natural background concentrations EPA used compared to APS did not significantly change the visibility modeling results.

In their March 16, 2009 letter to EPA, the USFS discusses the need for a more comprehensive characterization of a facility's impacts, particularly, for facilities like FCPP and NGS that affect visibility at multiple Class I areas. To account for cumulative impacts, the USFS suggested accounting for the total dv impact by summing across all days for all Class I areas. EPA agrees that alternative visibility metrics may assist in evaluating the visibility improvement associated with various control options at FCPP and NGS, including taking an average of the 98th percentile of all Class I areas or summing over all days for all Class I areas. Table 27 presents an alternative visibility metric that takes into account the size of the area over which controls provide visibility benefits. The 98th percentile for each Class I area is multiplied by its land area in km^2 and then summed. EPA is requesting comment on this, and other alternative visibility metrics. These metrics can then be used as an adjunct to cost effectiveness expressed in $/ton to assist EPA in evaluating the effectiveness of controls at FCPP and NGS on visibility improvement, as expressed in terms of dollar per deciview ($/dv) or $/dv-km^2.

TABLE 27—ALTERNATIVE VISIBILITY METRIC

	A (Baseline)	Visibility Impact (dv-km^2) after applying:			
		B (Wet ESP)	C2 (LNB)	D (SCR 3–5)	E2 (SCR 1–5)
Arches	1,014	1,012	816	615	461
Bandolier	249	246	193	156	119
Black Canyon	121	121	89	76	53
Canyon-lands	4,991	4,964	4,419	3,961	2,794
Capitol Reef	2,433	2,427	1,849	1,405	1,113
Grand Canyon	6,443	6,416	4,870	3,714	3,174
Great Sand Dunes	119	119	88	69	56
La Garita	699	697	518	394	295
Maroon Bells	571	569	415	315	238
Mesa Verde	1,112	1,109	939	818	666
Pecos	1,574	1,570	1,225	974	780
Petrified Forest	469	467	374	322	259
San Pedro	505	503	430	347	265
West Elk	2,996	2,988	2,221	1,614	1,207
Weminuche	1,525	1,522	1,170	860	636
Wheeler Peak	121	121	92	74	59
Sum over all areas	24,943	24,852	19,708	15,716	12,175

2. NGS

a. Visibility Modeling Scenarios

SRP conducted visibility modeling for NGS using CALPUFF based on estimated emission rates of various pollutants as inputs for the model. EPA conducted its own CALPUFF modeling using inputs that we determined were more representative.

EPA then modeled anticipated visibility improvements for four different options for installed control technologies. NGS's and EPA's modeling inputs are set forth in Tables 28–32 below. The modeling scenarios are:

A. Baseline Visibility Impact (modeled by NGS and EPA),

B. LNB + SOFA on Units 1–3 (modeled by NGS and EPA),

C. SCR + LNB + SOFA on Units 1 and 3, LNB + SOFA on Unit 2 (modeled by NGS and EPA),

D. SCR + LNB + SOFA on Units 1 and 3, Half-SCR + LNB + SOFA on Unit 2 (modeled by EPA),

E. SCR on Units 1–3 (modeled by NGS and EPA).

Scenarios C and E modeled by SRP and EPA were not listed as discrete modeling scenarios as they were for FCPP because the emission inputs for NGS from SRP and EPA, though different for PM fine and SO_4, are more similar to each other in terms of NO_X control than for FCPP. For Scenario E, SRP assumed NO_X emissions to be 0.08 lb/MMBtu, whereas EPA assumed 0.06 lb/MMBtu.

b. EPA Modifications to Emission Rate Inputs

Similar to FCPP, for the baseline and non-SCR emissions scenarios (Scenarios A and B), the main difference between SRP and EPA calculations for H_2SO_4 were from the assumed loss of H_2SO_4 in the air preheater. SRP used a penetration factor of 0.9 whereas EPA used a penetration factor of 0.49, which is consistent with the 2008 EPRI guidelines. Similarly for H_2SO_4 emissions resulting from the SCR scenarios, EPA used a 0.5% SO_2 to SO_3 conversion rate based on the application of an ultra-low oxidation catalyst.

For all modeling scenarios, EPA included HCl and HF emissions as PM fine modeling inputs and scaled them in a similar manner described for FCPP. For HCl, EPA used a scaled emission factor of 0.0025 lb/MMBtu, and for HF, EPA used a scaled emission factor of 0.00086 lb/MMBtu.

TABLE 28—SRP AND EPA BASELINE EMISSION RATES (SCENARIO A)

	Unit 1	Unit 2	Unit 3
SRP Baseline Modeling Inputs (in lb/hr)			
SO_2	487.75	526.92	576.17
SO_4	4.18	4.48	4.36
NO_X	4,271.42	4,207.50	4,181.67
SOA	35.18	37.69	36.63
PM fine	63.86	55.27	79.28
PM coarse	86.89	75.20	107.87
EC	2.45	2.12	3.05
EPA Baseline Modeling Inputs (in lb/hr)			
SO_2	487.75	526.92	576.17
SO_4	3.62	3.87	3.76
NO_X	4,271.42	4,207.50	4,181.67
SOA	35.18	37.69	36.63
PM fine	93.41	86.93	110.05
PM coarse	86.89	75.20	107.87

TABLE 28—SRP AND EPA BASELINE EMISSION RATES (SCENARIO A)—Continued

	Unit 1	Unit 2	Unit 3
EC	2.45	2.12	3.05

TABLE 29—SRP AND EPA EMISSIONS FOR LNB + SOFA (SCENARIO B)

	Unit 1	Unit 2	Unit 3
SRP Baseline Modeling Inputs (in lb/hr)			
SO_2	487.75	526.92	576.17
SO_4	4.18	4.48	4.36
NO_X	2,110.74	2,261.63	2,197.78
SOA	35.18	37.69	36.63
PM fine	63.86	55.27	79.28
PM coarse	86.89	75.20	107.87
EC	2.45	2.12	3.05
EPA Baseline Modeling Inputs (in lb/hr)			
SO_2	487.75	526.92	576.17
SO_4	3.62	3.87	3.76
NO_X	2,110.74	2,261.63	2,197.78
SOA	35.18	37.69	36.63
PM fine	93.41	86.93	110.05
PM coarse	86.89	75.20	107.87
EC	2.45	2.12	3.05

TABLE 30—SRP AND EPA EMISSIONS FOR SCR + LNB + SOFA ON UNITS 1 AND 3, LNB + SOFA ON UNIT 2 (SCENARIO C)

	Unit 1	Unit 2	Unit 3
SRP Baseline Modeling Inputs (in lb/hr)			
SO_2	487.75	526.92	576.17
SO_4	64.01	4.48	66.65
NO_X	703.58	2,261.63	732.59
SOA	35.18	37.69	36.63
PM fine	63.86	55.27	79.28
PM coarse	86.89	75.20	107.87
EC	2.45	2.12	3.05
EPA Baseline Modeling Inputs (in lb/hr)			
SO_2	487.75	526.92	576.17
SO_4	19.90	3.87	20.72
NO_X	615.63	2,261.63	641.02
SOA	35.18	37.69	36.63
PM fine	93.41	86.93	110.05
PM coarse	86.89	75.20	107.87
EC	2.45	2.12	3.05

TABLE 31—EPA EMISSIONS FOR SCR + LNB + SOFA ON UNITS 1 AND 3, HALF-SCR + LNB + SOFA ON UNIT 2 (SCENARIO D)

	Unit 1	Unit 2	Unit 3
EPA Baseline Modeling Inputs (in lb/hr)			
SO_2	487.75	526.92	576.17
SO_4	19.90	12.60	20.72
NO_X	615.63	1,696.22	641.02
SOA	35.18	37.69	36.63
PM fine	93.41	86.93	110.05
PM coarse	86.89	75.20	107.87
EC	2.45	2.12	3.05

TABLE 32—SRP AND EPA EMISSIONS FOR SCR + LNB + SOFA ON UNITS 1—3 (SCENARIO E)

	Unit 1	Unit 2	Unit 3
SRP Baseline Modeling Inputs (in lb/hr)			
SO_2	487.75	526.92	576.17
SO_4	64.01	68.59	66.65
NO_X	703.58	753.88	732.59
SOA	35.18	37.69	36.63
PM fine	63.86	55.27	79.28
PM coarse	86.89	75.20	107.87
EC	2.45	2.12	3.05
EPA Baseline Modeling Inputs (in lb/hr)			
SO_2	487.75	526.92	576.17
SO_4	19.90	21.32	20.72
NO_X	615.63	659.64	641.02
SOA	35.18	37.69	36.63
PM fine	93.41	86.93	110.05
PM coarse	86.89	75.20	107.87
EC	2.45	2.12	3.05

c. Ammonia Background and Natural Background

For ammonia background values at the Class I areas impacted by NGS, EPA used the same ammonia values listed in Table 22 above and the same natural background values listed in Table 23. See discussion of ammonia back-calculation methodologies and changes to natural background conditions described in Section II.B.1.

d. Visibility Modeling Results

To assess results from the CALPUFF model and post-processing steps, EPA used a least-squares regression analysis of all visibility modeling output from the 2001–2003 modeling period to determine the percent improvement in visibility compared to the baseline resulting from the application of control technologies. Table 33 shows EPA's modeled predicted visibility improvements at the 11 Class I areas within a 300 km radius of NGS.

SRP presented visibility improvement by comparing the 98th percentile (8th highest) of daily maximum deciview (dv) values from CALPUFF per Class I area, averaged over 2001–2003. Table 34 presents the visibility impacts of the 98th percentile of daily maxima for each Class I area for each year, averaged over 2001–2003, determined for NGS by SRP.

Table 35 presents the visibility impacts of the 98th percentile of daily maxima over 2001–2003 for each Class I area determined by EPA. Table 36 presents the alternative visibility metric determined by EPA for each Class I area.

TABLE 33—PERCENT IMPROVEMENT IN DECIVIEW IMPACTS FROM EPA MODELING AT EACH CLASS I AREA FROM NO_X CONTROLS AT NGS

	Scenario B (LNB) (percent)	Scenario C (SCR: 1&3) (percent)	Scenario D (½ SCR 2) (percent)	Scenario E (SCR: 1–3) (percent)
Arches	36	60	65	74
Bryce Canyon	26	47	53	63
Canyonlands	32	56	62	71
Capitol Reef	25	48	53	63
Grand Canyon	22	43	48	58
Mazatzal	38	60	65	72
Mesa Verde	40	63	68	76
Petrified Forest	36	60	65	74
Pine Mountain	38	59	64	71
Sycamore Canyon	36	59	64	72
Zion	31	54	60	69

TABLE 34—VISIBILITY IMPACTS (98TH PERCENTILE DV) OF NGS ON ELEVEN CLASS I AREAS AS MODELED BY SRP

	Baseline	Visibility Impact (dv) after applying:		
		LNB (B)	SCR (C)	SCR (E)
Arches	2.05	1.51	1.19	0.99
Bryce Canyon	2.00	1.58	1.36	1.23
Canyonlands	2.47	1.96	1.53	1.35
Capitol Reef	2.68	2.31	2.06	1.89
Grand Canyon	2.56	2.29	2.25	2.29
Mazatzal	0.71	0.47	0.41	0.38
Mesa Verde	1.42	1.04	0.77	0.58

TABLE 34—VISIBILITY IMPACTS (98TH PERCENTILE DV) OF NGS ON ELEVEN CLASS I AREAS AS MODELED BY SRP—Continued

	Baseline	Visibility Impact (dv) after applying:		
		LNB (B)	SCR (C)	SCR (E)
Petrified Forest	1.52	1.14	0.92	0.76
Pine Mountain	0.66	0.46	0.38	0.34
Sycamore Canyon	1.31	0.92	0.78	0.63
Zion	1.83	1.47	1.26	1.10
Sum of Class I areas	19.29	15.15	12.88	11.54

TABLE 35—VISIBILITY IMPACTS (98TH PERCENTILE DV) OF NGS ON ELEVEN CLASS I AREAS AS MODELED BY EPA

	Baseline	Visibility Impact (dv) after applying:			
		LNB (B)	SCR (C)	SCR (D)	SCR (E)
Arches	3.25	2.08	1.33	1.16	0.89
Bryce Canyon	3.66	2.44	1.57	1.39	1.10
Canyonlands	4.37	2.98	1.90	1.65	1.25
Capitol Reef	5.48	4.08	2.97	2.71	2.04
Grand Canyon	5.41	4.35	3.34	3.06	2.46
Mazatzal	1.16	0.73	0.48	0.45	0.37
Mesa Verde	2.24	1.33	0.78	0.67	0.52
Petrified Forest	2.62	1.54	1.00	0.86	0.66
Pine Mountain	1.08	0.64	0.42	0.38	0.32
Sycamore Canyon	1.96	1.28	0.80	0.71	0.59
Zion	3.73	2.65	1.65	1.44	1.05
Sum of Class I areas	34.95	24.10	16.25	14.48	11.23

TABLE 36—ALTERNATIVE VISIBILITY METRIC

	A (Baseline)	Visibility Impact (dv-km2) after applying:			
		B (LNB)	C (SCR: 1&3)	D (½ SCR 2)	E (SCR: 1–3)
Arches	812	514	336	293	223
Bryce Canyon	495	324	212	187	147
Canyonlands	4,649	3,071	2,022	1,741	1,320
Capitol Reef	4,184	3,127	2,233	2,031	1,566
Grand Canyon	21,399	17,219	13,157	12,033	9,698
Mazatzal	978	618	410	367	297
Mesa Verde	383	226	135	115	87
Petrified Forest	847	515	313	270	217
Pine Mountain	72	44	28	25	22
Sycamore Canyon	390	235	162	144	120
Zion	1,574	1,104	739	649	494
Sum over all areas	24,943	19,708	19,708	15,716	19,708

C. Factor 2: Energy and Non-Air Quality Impacts

1. FCPP

The application of LNB and LNB + OFA to control NO_X by staging combustion to reduce boiler temperatures will result in reduced NO_X formation as well as reduced combustion efficiency. The reduced combustion temperatures thus result in increased emissions of carbon monoxide (CO), volatile organic compounds (VOCs), and increased unburned carbon in the fly ash, known as loss of ignition (LOI). Increases in CO, and potential increases in VOC, from LNB or LNB + OFA, may trigger the Prevention of Significant Deterioration (PSD) permitting requirements, including the application of Best Available Control Technology (BACT) if the emission increases exceed the 100 tpy CO and 40 tpy VOC significance thresholds. Increased LOI in fly ash may reduce the desirability of the fly ash for sale and reuse.

Emissions of sulfuric acid (H_2SO_4) from coal fired power plants result from the conversion of sulfur in the coal into SO_2 and further oxidation to SO_3 during the combustion process in the boiler. SO_3 can then combine with moisture (H_2O) in the flue gas to form H_2SO_4. Fuels high in vanadium can catalyze SO_2 to SO_3 at higher rates than low vanadium fuels and result in higher H_2SO_4 emissions. The use of SCR catalysts, in particular, SCR catalysts that use vanadium, can result in increased emissions of H_2SO_4. Emissions increases in H_2SO_4 at existing major stationary sources as a result of the application of SCR for NO_X control will trigger PSD permitting requirements, including the application of BACT, if they exceed the H_2SO_4 significance threshold of 7 tpy. Add-on control technologies exist to help reduce H_2SO_4 emissions following SO_2 to SO_3 conversion from combustion and SCR, including injection of reagents (*e.g.*, hydrated lime, sodium bisulfite) to convert H_2SO_4 to particulate matter that is then captured by downstream PM control devices, such as baghouses. Based on discussions with URS Corporation, the commercial vendor for sodium bisulfite (SBS) injection technology, the expected low concentrations of H_2SO_4 at FCPP, compared to coal-fired facilities in the Midwestern and Eastern states, suggests the application of reagent injection will not effectively reduce H_2SO_4 emissions from FCPP. Based on a recent PSD permit issued to the Coronado Generating Station in Arizona, the use of an ultra-low conversion catalyst (achieving no more than 0.5% SO_2 to SO_3 conversion) currently represents BACT.

In addition to the impact of SCR on H_2SO_4 emissions, the application of SCR reduces the energy efficiency of the facility by increasing parasitic load from the use of additional fans to overcome increased resistance created by SCR.

2. NGS

As described above, the use of LNB + SOFA for NO_X control results in potential increases in emissions of CO and VOC, and increased LOI of fly ash. Additionally, the impacts associated with SCR, *i.e.*, H_2SO_4 emissions increases, the limited efficacy of reagent injection for H_2SO_4 control, and energy impacts, also apply to NGS. NGS additionally identified another concern related to SCR resulting from the need for daily deliveries by tanker truck of anhydrous ammonia for the SCR system.

D. Factor 3: Existing Controls at the Facility

1. FCPP

Existing controls at FCPP are shown in Table 37.

TABLE 37—EXISTING AIR POLLUTION CONTROLS AT FCPP

	NO_X control	PM control	SO_2 control
Unit 1	none	Venturi Scrubber (VS)	VS.
Unit 2	LNB	VS—Lime	VS—Lime.
Unit 3	LNB	VS—Lime	VS—Lime.
Unit 4	LNB	Reverse Gas Fabric Filter (Baghouse)	Tray Tower Flue Gas Desulfurization (FGD).
Unit 5	LNB	Baghouse	Tray Tower FGD.

a. Existing NO_X Controls at FCCP

For the SCR control case, EPA conducted visibility modeling for FCPP (Table 21, Scenario E2) without the addition of LNB + OFA, whereas APS modeled an SCR control case assuming LNB + OFA could provide further control of NO_X emissions (Scenario E1). FCPP emits more NO_X than any other coal-fired power plant in the U.S. This is due to both the size of the facility and the high average concentration of NO_X emitted from each unit. Every unit at FCPP emits NO_X at a higher concentration than any other unit in Region IX.

The potential for successfully obtaining significant reductions of NO_X using only combustion controls, such as LNB, at this facility is limited. The fireboxes for Units 1, 2 and 3 are considered to be too small to effectively utilize modern approaches to low NO_X combustion which require separated overfire air. Unit 2 was retrofitted with a 1990-designed LNB and, according to APS, had considerable operational problems subsequent to this retrofit. Units 1 and 2 are identical boilers. Thus due to operational difficulties following the Unit 2 retrofit, APS did not attempt a retrofit on Unit 1, which continues to emit NO_X at a concentration of 0.8 lb/MMBtu. Due to their small size, EPA has determined that a retrofit of Units 1 and 2 with LNB and Unit 3 with LNB + OFA will not provide significant NO_X control.

Units 4 and 5 were originally designed and operated with cell burners. This type of combustion burner inherently creates more NO_X than conventional wall-fired burners. Although these burners were replaced in the 1980s, the design of a cell burner boiler limits the NO_X reduction that can be achieved with modern low NO_X combustion techniques. EPA has set different presumptive levels for the expected achievable NO_X reductions for cell burner boilers with combustion modifications due to this design limitation. Thus, the efficacy of LNB + OFA on Units 4 and 5 will also be limited by their inherent design. EPA is requesting comment on the potential efficacy of LNB + OFA on all Units at FCPP.

b. Existing PM Controls at FCCP

Units 1, 2, and 3 utilize venturi scrubbers for both PM and SO_2 control. These scrubbers operate at pressure drops less than 10 inches of water. Venturi scrubbers have not been installed for PM pollution control on any coal fired EGU in Region IX since the early 1970s. This was principally due to concerns over the ability of venturi scrubbers to continuously meet the 0.10 lb/MMBtu standard in a 1971 regulation. Fossil fuel fired boiler standards for coal fired units were revised for units built after 1978 and the PM limit was lowered to 0.03 lb/MMbtu. Most current coal fired boilers now use baghouses which are capable of meeting PM limits of about 0.01 to 0.012 lb/MMBtu (Method 5 front half PM measurement).

In Region IX, all other coal fired EGUs controlled by venturi scrubbers have been retrofit with new PM controls. Unit 1 at APS's Cholla power plant was retrofit with a baghouse in 2007, in order to meet a new 20% opacity standard established by the ADEQ. APS received an extended compliance schedule for meeting that opacity standard to allow for the installation of the new baghouse. Three units at the Nevada Energy Reid Gardner facility also have venturi scrubbers for PM control. These units are required by a consent decree between Nevada Energy, and Nevada Department of Environmental Protection and EPA, to install new baghouses in 2010. EPA is requesting comment on whether the existing controls on Units 1–3 at FCPP meet BART for PM.

2. NGS

Existing controls at NGS are shown in Table 38.

TABLE 38—EXISTING AIR POLLUTION CONTROLS AT NGS

	NO_X control	PM control	SO_2 control
Units 1–3	LNB + SOFA[29]	Hot-side ESP	Wet FGD

E. Factor 4: Remaining Useful Life of Facility

1. FCPP

The remaining useful life of the facility is often expressed in terms of the amortization period used to annualize the costs of control. In its analysis, APS used an amortization period of 20 years, anticipating that the remaining useful life of Units 1–5 is at least 20 years.

EPA is requesting comment on the use of this period of time for the remaining useful life of FCPP.

2. NGS

In its analysis, SRP used an amortization period of 20 years, anticipating that the remaining useful life of Units 1–3 is at least 20 years.

EPA is also requesting comment on the use of this period of time for the remaining useful life of NGS.

III. Statutory and Executive Order Reviews

Under Executive Order 12866, entitled *Regulatory Planning and Review* (58 FR 51735, October 4, 1993), this is not a ''significant regulatory action.'' Because this action does not propose or impose any requirements, the various statutes and Executive Orders that apply to rulemaking do not apply in this case. In addition, this notice covers two facilities. Any future rulemaking would be separate, one for each facility. Determinations of significance and applicability of any Executive Order or statute would depend upon the content of each individual rulemaking. Should EPA subsequently determine to pursue rulemaking and propose BART for these facilities, EPA will address the statutes and Executive Orders as applicable to those individual proposed actions.

Nevertheless, the Agency welcomes comments and/or information that would help the Agency to assess any of the following: tribal implications pursuant to Executive Order 13175, entitled *Consultation and Coordination with Indian Tribal Governments* (65 FR 67249, November 6, 2000); environmental health or safety effects on children pursuant to Executive Order 13045, entitled *Protection of Children from Environmental Health Risks and Safety Risks* (62 FR 19885, April 23, 1997); energy effects pursuant to Executive Order 13211, entitled *Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use* (66 FR 28355, May 22, 2001); Paperwork burdens pursuant to the Paperwork Reduction Act (PRA) (44 U.S.C. 3501); or human health or environmental effects on minority or low-income populations pursuant to Executive Order 12898, entitled *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations* (59 FR 7629, February 16, 1994). The Agency will consider such comments during the development of any subsequent rulemaking.

[29] On November 20, 2008, EPA Region IX issued a PSD permit authorizing NGS to modify Units 1–3 with LNB + SOFA over 2009–2011.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Oxides of nitrogen, Particulate matter, Regional haze.

Authority: 42 U.S.C. 7401 *et seq.*

Dated: August 19, 2009.

Laura Yoshii,

Acting Regional Administrator, Region IX.

[FR Doc. E9–20826 Filed 8–27–09; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R09–OAR–2009–0385; FRL–8948–5]

Revisions to the California State Implementation Plan, San Joaquin Valley Unified Air Pollution Control District and Santa Barbara County Air Pollution Control District

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA is proposing to approve revisions to the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) and the Santa Barbara County Air Pollution Control (SBCAPCD) portions of the California State Implementation Plan (SIP). We are proposing to approve these local rules that are administrative and address changes for clarity and consistency under the Clean Air Act as amended in 1990 (CAA or the Act).

DATES: Any comments on this proposal must arrive by September 28, 2009.

ADDRESSES: Submit comments, identified by docket number EPA–R09–OAR–2009–0385, by one of the following methods:

1. *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the on-line instructions.
2. *E-mail: steckel.andrew@epa.gov.*
3. *Mail or deliver:* Andrew Steckel (Air-4), U.S. Environmental Protection Agency Region IX, 75 Hawthorne Street, San Francisco, CA 94105–3901.

Instructions: All comments will be included in the public docket without change and may be made available online at *http://www.regulations.gov*, including any personal information provided, unless the comment includes Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Information that you consider CBI or otherwise protected should be clearly identified as such and should not be submitted through *http://www.regulations.gov* or e-mail. *http://www.regulations.gov* is an ''anonymous access'' system, and EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send e-mail directly to EPA, your e-mail address will be automatically captured and included as part of the public comment. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses.

Docket: The index to the docket for this action is available electronically at *http://www.regulations.gov* and in hard copy at EPA Region IX, 75 Hawthorne Street, San Francisco, California. While all documents in the docket are listed in the index, some information may be publicly available only at the hard copy location (*e.g.,* copyrighted material), and some may not be publicly available in either location (*e.g.,* CBI). To inspect the hard copy materials, please schedule an appointment during normal business hours with the contact listed in the **FOR FURTHER INFORMATION CONTACT** section.

FOR FURTHER INFORMATION CONTACT: Cynthia G. Allen, EPA Region IX, (415) 947–4120, *allen.cynthia@epa.gov.*