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## Part II

## Environmental Protection Agency

40 CFR Part 51

Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans; Proposed Rule

**ENVIRONMENTAL PROTECTION AGENCY**

**40 CFR Part 51**

**[EPA–R09–OAR–2012–0021, FRL–9700–1]**

## Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Proposed rule.

**SUMMARY:** EPA is proposing to approve partially and disapprove partially a revision to Arizona's State Implementation Plan (SIP) to implement the regional haze program for the first planning period through July 31, 2018. This proposed action addresses only the portion of the SIP related to Arizona's determination of Best Available Retrofit Technology (BART) to control emissions from eight units at three electric generating stations: Apache Generating Station, Cholla Power Plant and Coronado Generating Station. EPA proposes to approve the State's determination that these sources are subject to BART, and to approve the emissions limits for sulfur dioxide ($SO_2$) and particulate matter ($PM_{10}$) at all the units. EPA proposes to disapprove the BART emissions limits for nitrogen oxides ($NO_X$) at most of the units. EPA also proposes to promulgate a Federal Implementation Plan (FIP) containing new emissions limits for $NO_X$ as well as BART compliance requirements for the three facilities. We encourage the State to submit a revised SIP to replace all portions of our FIP, and we stand ready to work with the State to develop a revised plan. The Clean Air Act (CAA) requires states to prevent any future and remedy any existing man-made impairment of visibility in 156 national parks and wilderness areas designated as Class I areas. Arizona has a wealth of such areas. The three power plants affect visibility at 18 national parks and wilderness areas, including the Grand Canyon, Mesa Verde and the Petrified Forest. The State and EPA must work together to ensure that plans are in place to make progress toward natural visibility conditions at these national treasures.

**DATES:** Written comments must be received by the designated contact at the address below on or before August 31, 2012.

**ADDRESSES:** See the **SUPPLEMENTARY INFORMATION** section for further instructions on where and how to learn more about this proposal, attend a public hearing, or submit comments.

**FOR FURTHER INFORMATION CONTACT:** Thomas Webb, U.S. EPA, Region 9, Planning Office, Air Division, Air-2, 75 Hawthorne Street, San Francisco, CA 94105. Thomas Webb can be reached at telephone number (415) 947–4139 and via electronic mail at *webb.thomas@epa.gov.*

**SUPPLEMENTARY INFORMATION:**

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## I. General Information

### *A. Definitions*

For the purpose of this document, we are giving meaning to certain words or initials as follows:

(1) The words or initials *Act* or *CAA* mean or refer to the Clean Air Act, unless the context indicates otherwise.

(2) The initials *ADEQ* mean or refer to the Arizona Department of Environmental Quality.

(3) The initials *AEPCO* mean or refer to Arizona Electric Power Cooperative.

(4) The initials *AFUDC* mean or refer to allowance for funds used during construction.

(5) The initials *APS* mean or refer Arizona Public Service Company.

(6) The words *Arizona* and *State* mean the State of Arizona.

(7) The initials *BART* mean or refer to Best Available Retrofit Technology.

(8) The term *Class I area* refers to a mandatory Class I Federal area.[1]

(9) The initials *CBI* mean or refer to Confidential Business Information.

(10) The initials *CEMS* mean or refer to continuous emission monitoring system.

(11) The initials *COFA* mean or refer to close-coupled overfire air.

(12) The initials *CY* mean or refer to Calendar Year

(13) The initials *EGU* mean or refer to Electric Generating Unit.

(14) The initials *ESPs* mean or refer to electrostatic precipitators.

(15) The words *EPA, we, us* or *our* mean or refer to the United States Environmental Protection Agency.

[1] Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to "mandatory Class I Federal areas."

(16) The initials *FGD* mean or refer to flue gas desulfurization.

(17) The initials *FGR* mean or refer to flue gas recirculation.

(18) The initials *FIP* mean or refer to Federal Implementation Plan.

(19) The initials *FLMs* mean or refer to Federal Land Managers.

(20) The initials *IMPROVE* mean or refer to Interagency Monitoring of Protected Visual Environments monitoring network.

(21) The initials *IPM* mean or refer to Integrated Planning Model.

(22) The initials *LNB* mean or refer to low-$NO_X$ burners.

(23) The initials *LTS* mean or refer to Long-Term Strategy.

(24) The initials *MW* mean or refer to megawatts.

(25) The initials *NEI* mean or refer to National Emission Inventory.

(26) The initials $NH_3$ mean or refer to ammonia.

(27) The initials $NO_X$ mean or refer to nitrogen oxides.

(28) The initials *NP* mean or refer to National Park.

(29) The initials *OC* mean or refer to organic carbon.

(30) The initials *OFA* mean or refer to over fire air.

(31) The initials *PM* mean or refer to particulate matter.

(32) The initials $PM_{2.5}$ mean or refer to fine particulate matter with an aerodynamic diameter of less than 2.5 micrometers.

(33) The initials $PM_{10}$ mean or refer to particulate matter with an aerodynamic diameter of less than 10 micrometers (coarse particulate matter).

(34) The initials *PNG* mean or refer to pipeline natural gas.

(35) The initials *ppm* mean or refer to parts per million.

(36) The initials *PSD* mean or refer to Prevention of Significant Deterioration.

(37) The initials *RAVI* mean or refer to Reasonably Attributable Visibility Impairment.

(38) The initials *RMC* mean or refer to Regional Modeling Center.

(39) The initials *RP* mean or refer to Reasonable Progress.

(40) The initials *RPG* or *RPGs* mean or refer to Reasonable Progress Goal(s).

(41) The initials *RPOs* mean or refer to regional planning organizations.

(42) The initials *SCR* mean or refer to Selective Catalytic Reduction.

(43) The initials *SIP* mean or refer to State Implementation Plan.

(44) The initials *SNCR* mean or refer to Selective Non-catalytic Reduction.

(45) The initials $SO_2$ mean or refer to sulfur dioxide.

(46) The initials *SOFA* mean or refer to separated over fire air.

(47) The initials *SRP* mean or refer to Salt River Project Agricultural Improvement and Power District.

(48) The initials *tpy* mean tons per year.

(49) The initials *TSD* mean or refer to Technical Support Document.

(50) The initials *VOC* mean or refer to volatile organic compounds.

(51) The initials *WA* mean or refer to Wilderness Area.

(52) The initials *WEP* mean or refer to Weighted Emissions Potential.

(53) The initials *WFGD* mean or refer to wet flue gas desulfurization.

(54) The initials *WRAP* mean or refer to the Western Regional Air Partnership.

*B. Docket*

The proposed action relies on documents, information and data that are listed in the index on *http://www.regulations.gov* under docket number EPA–R09–OAR–2012–0021. Although listed in the index, some information is not publicly available (e.g., Confidential Business Information (CBI)). Certain other material, such as copyrighted material, is publicly available only in hard copy form. Publicly available docket materials are available either electronically at *http://www.regulations.gov* or in hard copy at the Planning Office of the Air Division, AIR–2, EPA Region 9, 75 Hawthorne Street, San Francisco, CA 94105. EPA requests that you contact the individual listed in the **FOR FURTHER INFORMATION CONTACT** section to view the hard copy of the docket. You may view the hard copy of the docket Monday through Friday, 9–5:00 PDT, excluding Federal holidays.

*C. Instructions for Submitting Comments to EPA*

Written comments must be received at the address below on or before August 31, 2012. Submit your comments, identified by Docket ID No. EPA–R09–OAR–2011–0021, by one of the following methods:

• *Federal Rulemaking portal: http://www.regulations.gov.* Follow the on-line instructions for submitting comments.

• *Email: Arizona_Regional_Haze@epa.gov.*

• *Fax:* 415–947–3579 (Attention: Thomas Webb).

• *Mail, Hand Delivery or Courier:* Thomas Webb, EPA Region 9, Air Division (AIR–2), 75 Hawthorne Street, San Francisco, California 94105. Hand and courier deliveries are only accepted Monday through Friday, 8:30 a.m.–4:30 p.m., excluding Federal holidays. Special arrangements should be made for deliveries of boxed information.

EPA's policy is to include all comments received in the public docket without change. We may make comments available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be CBI or other information for which disclosure is restricted by statute. Do not submit information that you consider to be CBI or that is otherwise protected through *http://www.regulations.gov* or email. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to EPA, without going through *http://www.regulations.gov,* we will include your email address as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. 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 not include special characters or any form of encryption, and be free of any defects or viruses.

*D. Submitting Confidential Business Information*

Do not submit CBI to EPA through *http://www.regulations.gov* or email. Clearly mark the part or all of the information that you claim as CBI. For CBI information in a disk or CD–ROM that you mail to EPA, mark the outside of the disk or CD–ROM as CBI and identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, you must submit a copy of the comment that does not contain the information claimed as CBI for inclusion in the public docket. We will not disclose information so marked except in accordance with procedures set forth in 40 CFR part 2.

*E. Tips for Preparing Your Comments*

When submitting comments, remember to:

• Identify the rulemaking by docket number and other identifying information (e.g., subject heading, **Federal Register** date and page number).

• Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

- Describe any assumptions and provide any technical information and/or data that you used.
- If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.
- Provide specific examples to illustrate your concerns, and suggest alternatives.
- Explain your views as clearly as possible, avoiding the use of profanity or personal threats.
- Make sure to submit your comments by the identified comment period deadline.

*F. Public Hearings*

EPA will hold a public hearing at the date, time and location stated below to accept oral and written comments into the record.

*Date:* July 31, 2012.

*Open House:* 4:00–5:00 p.m.

*Public Hearing:* 6:00–8:00 p.m.

*Location:* Sandra Day O'Connor Federal Courthouse (atrium and juror room), 401 W. Washington Street, Phoenix, AZ 85003–2118.

To provide opportunities for questions and discussion, EPA will hold an open house prior to the public hearing. During the open house, EPA staff will be available informally to answer questions on our proposed rule. Any comments made to EPA staff during the open house must still be provided formally in writing or orally during a public hearing in order to be considered in the record.

The public hearing will provide the public with an opportunity to present views or information concerning the proposed Regional Haze FIP for Arizona. EPA may ask clarifying questions during the oral presentations, but will not respond to the presentations at that time. Simultaneous translation in Spanish will be available during the public hearing. We will consider written statements and supporting information submitted during the comment period with the same weight as any oral comments and supporting information presented at the public hearing. Please consult section I.C, I.D. and I.E of this preamble for guidance on how to submit written comments to EPA. We will include verbatim transcripts of the hearing in the docket for this action. The EPA Region 9 Web site for the rulemaking, which includes the proposal and information about the public hearing, is at *http://www.epa.gov/region9/air/actions*.

**II. Overview of Proposed Actions**

EPA proposes to partially approve and partially disapprove a portion of Arizona's SIP for Regional Haze submitted to EPA Region 9 on February 28, 2011, to meet the requirements of Section 308 of the Regional Haze Rule. EPA is proposing to take action only on the BART requirements for the three electric generating stations and units listed in Table 1. At this time, EPA is not proposing to take action on the State's other BART determinations or any other parts of the SIP regarding the remaining requirements of the Regional Haze Rule. EPA takes very seriously a decision to disapprove a state plan, as we believe that it is preferable, and preferred in the provisions of the Clean Air Act, that these requirements be implemented through state plans. A state plan need not contain exactly the same provisions that EPA might require, but EPA must be able to find that the state plan is consistent with the requirements of the Act. Further, EPA's oversight role requires that it assure fair implementation of Clean Air Act requirements by states across the country, even while acknowledging that individual decisions from source to source or state to state may not have identical outcomes. In this instance, we believe that Arizona's SIP generally meets those requirements with respect to its $SO_2$ and $PM_{10}$ limits, but as we describe in more detail below, the SIP does not include several specifically required elements. The $NO_X$ BART determinations for the coal-fired units are neither consistent with the requirements of the Act nor with BART decisions that other states have made. As a result, EPA believes this proposed disapproval is the only path that is consistent with the Act at this time. Specifically, we propose the following:

- *Proposed Approval:* EPA proposes to approve Arizona's determination that the following sources and units are subject to BART: Arizona Electric Power Company's (AEPCO) Apache Generating Station (Apache) Units 1, 2 and 3; Arizona Public Service's (APS) Cholla Power Plant (Cholla) Units 2, 3 and 4; and Salt River Project's (SRP) Coronado Generating Station (Coronado) Units 1 and 2. We are proposing to approve the State's emissions limits for $SO_2$ and $PM_{10}$ at all of these units, but are seeking comment on whether lower emissions limits may be warranted for any of these units, and whether an alternative test method should be accepted for measurement of $PM_{10.}$ Finally, we are proposing to approve the emissions limits for $NO_X$, $SO_2$ and $PM_{10}$ at Apache Unit 1.
- *Proposed Disapproval:* Based on our evaluation described in this notice, we propose to disapprove the State's BART emissions limits for $NO_X$ at all three sources and units except for Coronado Unit 2 and Apache Unit 1. We also propose to disapprove the compliance and equipment maintenance requirements for BART at all three sources, since these were not included in the revised SIP.[2]
- *Proposed FIP:* We propose to promulgate a Federal Implementation Plan (FIP) that includes emissions limitations representing BART for $NO_X$ at all units except for Apache Unit 1. The proposed FIP also includes compliance schedules and requirements for equipment maintenance, monitoring, testing, recordkeeping and reporting for all the sources and units. The regulatory language for the FIP requirements is listed under PART 52 at the end of this notice.

TABLE 1—SCOPE OF PROPOSED ACTION

| Source name | Owner | Units | Pollutants |
|---|---|---|---|
| Apache Generating Station | AEPCO | Steam Units 1, 2 and 3 | $NO_X$, $SO_2$, $PM_{10}$ |
| Cholla Power Plant | APS | Steam Units 2, 3 and 4 | $NO_X$, $SO_2$, $PM_{10}$ |
| Coronado Generating Station | SRP | Units 1 and 2 | $NO_X$, $SO_2$, $PM_{10}$ |

[2] For each BART source, the SIP must include a requirement to install and operate control equipment as expeditiously as practicable (40 CFR 51.308(e)(1)(iv)); a requirement to maintain control equipment (40 CFR 51.308(e)(1)(v)); and procedures to ensure control equipment is properly operated and maintained, including requirements for monitoring, recordkeeping and reporting (40 CFR 51.308(e)(1)(v)).

## III. Regional Haze Background

### A. Description of Regional Haze

Regional haze is visibility impairment that is produced by a multitude of sources and activities that are located across a broad geographic area and emit fine particulates (e.g., sulfates, nitrates, organic carbon (OC), elemental carbon (EC), and soil dust), and their precursors (e.g., sulfur dioxide, nitrogen oxides, and in some cases, ammonia ($NH_3$) and volatile organic compounds (VOC)). Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that one can see. $PM_{2.5}$ can also cause serious health effects and mortality in humans and contributes to environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the ''Interagency Monitoring of Protected Visual Environments'' (IMPROVE) monitoring network, show that visibility impairment caused by air pollution occurs virtually all the time at most national parks (NPs) and wilderness areas (WAs). The average visual range [3] in many Class I areas (i.e., NPs and memorial parks, WAs, and international parks meeting certain size criteria) in the western United States is 100–150 kilometers, or about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. In most of the eastern Class I areas of the United States, the average visual range is less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions (64 FR 35715, July 1, 1999).

### B. History of Regional Haze Regulations

In section 169A of the 1977 Amendments to the CAA, Congress created a program for protecting visibility in the nation's national parks and wilderness areas. This section of the CAA establishes as a national goal the ''prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas [4] which impairment results from manmade air pollution.'' EPA promulgated regulations on December 2, 1980, to address visibility impairment in Class I areas that is ''reasonably attributable'' to a single source or small group of sources, *i.e.,* ''reasonably attributable visibility impairment.'' (45 FR 80084, December 2, 1980). These regulations represented the first phase in addressing visibility impairment. EPA deferred action on regional haze that emanates from a variety of sources until monitoring, modeling and scientific knowledge about the relationships between pollutants and visibility impairment were improved.

As part of the 1990 Amendments to the CAA, Congress added section 169B to focus attention on regional haze issues. EPA promulgated a rule to address regional haze on July 1, 1999 (64 FR 35714, July 1, 1999) codified at 40 CFR part 51, subpart P (Regional Haze Rule). The primary regulatory requirements that address regional haze are found at 40 CFR 51.308 and 51.309 and are summarized below. Under 40 CFR 51.308(b), all states, the District of Columbia and the Virgin Islands are required to submit an initial state implementation plan (SIP) addressing regional haze visibility impairment no later than December 17, 2007.[5]

### C. Roles of Agencies in Addressing Regional Haze

Successful implementation of the regional haze program will require long-term regional coordination among states, tribal governments and various federal agencies. As noted above, pollution affecting the air quality in Class I areas can be transported over long distances, even hundreds of kilometers. Therefore, to effectively address the problem of visibility impairment in Class I areas, states, or the EPA when implementing a FIP, need to develop strategies in coordination with one another, taking into account the effect of emissions from one jurisdiction on the air quality in another.

Because the pollutants that lead to regional haze can originate from sources located across broad geographic areas, EPA has encouraged the states and tribes across the United States to address visibility impairment from a regional perspective. Five regional planning organizations (RPOs) were developed to address regional haze and related issues. The RPOs first evaluated technical information to better understand how their states and tribes impact Class I areas across the country, and then pursued the development of regional strategies to reduce emissions of particulate matter and other pollutants leading to regional haze.

The Western Regional Air Partnership (WRAP) RPO is a collaborative effort of state governments, tribal governments, and various federal agencies established to initiate and coordinate activities associated with the management of regional haze, visibility and other air quality issues in the western United States. WRAP member State governments include: Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. Tribal members include Campo Band of Kumeyaay Indians, Confederated Salish and Kootenai Tribes, Cortina Indian Rancheria, Hopi Tribe, Hualapai Nation of the Grand Canyon, Native Village of Shungnak, Nez Perce Tribe, Northern Cheyenne Tribe, Pueblo of Acoma, Pueblo of San Felipe, and Shoshone-Bannock Tribes of Fort Hall.

## IV. Requirements for Regional Haze Implementation Plans

### A. Regional Haze Rule

The Regional Haze Rule (RHR) sets out specific requirements for states' initial regional haze implementation plans.[6] In particular, each state's plan must establish a long-term strategy that ensures reasonable progress toward achieving natural visibility conditions in each Class I area affected by the emissions from sources within the state. In addition, for each Class I area within the state's boundaries, the plan must establish a reasonable progress goal (RPG) for the first planning period that ends on July 31, 2018. The long-term strategy must include enforceable emission limits and other measures as necessary to achieve the RPG. Regional haze plans must also give specific

[3] Visual range is the greatest distance, in kilometers or miles, at which a dark object can be viewed against the sky.

[4] Areas designated as mandatory Class I Federal areas consist of national parks exceeding 6000 acres, wilderness areas and national memorial parks exceeding 5000 acres, and all international parks that were in existence on August 7, 1977. 42 U.S.C. 7472(a). In accordance with section 169A of the CAA, EPA, in consultation with the Department of Interior, promulgated a list of 156 areas where visibility is identified as an important value (44 FR 69122, November 30, 1979). The extent of a mandatory Class I area includes subsequent changes in boundaries, such as park expansions. 42 U.S.C. 7472(a). Although states and tribes may designate as Class I additional areas which they consider to have visibility as an important value, the requirements of the visibility program set forth in section 169A of the CAA apply only to ''mandatory Class I Federal areas.'' Each mandatory Class I Federal area is the responsibility of a ''Federal Land Manager.'' 42 U.S.C. 7602(i). When we use the term ''Class I area'' in this action, we mean a ''mandatory Class I Federal area.''

[5] EPA's regional haze regulations require subsequent updates to the regional haze SIPs. 40 CFR 51.308(g)–(i).

[6] Pursuant to 40 CFR 51.301, ''implementation plan'' is defined as ''any State Implementation Plan, Federal Implementation Plan, or Tribal Implementation Plan.'' Therefore, although the requirements of the RHR are generally described in relation to SIPs, they are also relevant where EPA is promulgating a regional haze plan.

attention to certain stationary sources that were in existence on August 7, 1977, but were not in operation before August 7, 1962. These sources, where appropriate, are required to install BART controls to eliminate or reduce visibility impairment. Although such BART determinations can be a part of a reasonable progress strategy, BART is also an independent requirement that can be assessed separately from the other requirements of the RHR. Because this proposal only pertains to BART at three specific sources, we do not discuss other requirements of the RHR below.

*B. The Deciview*

The RHR establishes the deciview (dv) as the principal metric for measuring visibility. This visibility metric expresses uniform changes in haziness in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions. Visibility expressed in deciviews is determined by using air quality measurements to estimate light extinction and then transforming the value of light extinction to deciviews using a logarithmic function. The deciview is a more useful measure for tracking progress in improving visibility than light extinction because each deciview change is an equal incremental change in visibility as perceived by the human eye.[7]

*C. Best Available Retrofit Technology*

Section 169A of the CAA directs states to evaluate the use of retrofit controls at certain larger, often uncontrolled, older stationary sources in order to address visibility impacts from these sources. Specifically, section 169A(b)(2)(A) of the CAA requires states to revise their SIPs to contain such measures as may be necessary to make reasonable progress towards the natural visibility goal, including a requirement that certain categories of existing major stationary sources[8] built between 1962 and 1977 procure, install, and operate the ''Best Available Retrofit Technology'' as determined by the state. Under the RHR, states are directed to conduct BART determinations for such ''BART-eligible'' sources that may be anticipated to cause or contribute to any visibility impairment in a Class I area. Rather than requiring source-specific BART controls, states also have the flexibility to adopt an emissions trading program or other alternative program as long as the alternative provides greater reasonable progress towards improving visibility than BART.

EPA published the Guidelines for BART Determinations under the Regional Haze Rule at Appendix Y to 40 CFR part 51 (hereinafter referred to as the ''BART Guidelines'') on July 6, 2005. The Guidelines are to assist states in determining which of their sources should be subject to the BART requirements and in determining appropriate emission limits for each such ''subject-to-BART'' source. In making BART determinations for fossil fuel-fired electric generating plants with a total generating capacity in excess of 750 megawatts, states must use the approach set forth in the BART Guidelines. States are encouraged, but not required, to follow the BART Guidelines in making BART determinations for other types of sources. States must address all visibility-impairing pollutants emitted by a source in the BART determination process. The most significant visibility impairing pollutants are $SO_2$, $NO_X$ and PM. EPA has indicated that states should use their best judgment in determining whether VOC or $NH_3$ compounds impair visibility in Class I areas.

Under the BART Guidelines, states may select an exemption threshold value for their BART modeling, below which a BART-eligible source would not be expected to cause or contribute to visibility impairment in any Class I area. The state must document this exemption threshold value in the SIP and must state the basis for its selection of that value. Any source with emissions that model above the threshold value would be subject to a BART determination review. The BART Guidelines acknowledge varying circumstances affecting different Class I areas. In setting their exemption threshold values, states should consider the number of emission sources affecting the Class I areas at issue and the magnitude of the individual sources' impacts. An exemption threshold set by the state should not be higher than 0.5 deciview.

In their SIPs, states must identify potential BART sources, described in the RHR as ''BART-eligible sources,'' and document their BART control determination analyses. In making BART determinations, section 169A(g)(2) of the CAA requires that states consider the following factors: (1) The costs of compliance; (2) the energy and non-air quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. States are free to determine the weight and significance assigned to each factor, but must consider all five factors and provide a reasoned explanation for adopting the technology selected as BART, based on the five factors.

A regional haze SIP must include source-specific BART emission limits and compliance schedules for each source subject to BART, unless the SIP includes an alternative program that provides greater reasonable progress towards improving visibility than BART and meets the other requirements of 40 CFR 51.308(e)(2). Once a state has made its BART determination, the BART controls must be installed and in operation as expeditiously as practicable, but no later than five years after the date EPA approves the regional haze SIP.[9] The Regional Haze SIP must also contain a requirement for each BART source to maintain the relevant control equipment, as well as procedures to ensure control equipment is properly operated and maintained.[10] In addition to what is required by the RHR, general SIP requirements mandate that the SIP must also include all regulatory requirements related to monitoring, recordkeeping and reporting for the BART emissions limitations.[11]

*D. The Grand Canyon Visibility Transport Commission and Section 309*

In addition to the general requirements of the regional haze program, the RHR also includes 40 CFR 51.309, which contains the strategies developed by the Grand Canyon Visibility Transport Commission (GCVTC), established under Section 169B(f) of CAA, 42 U.S.C. 7492(f). Certain western States and Tribes were eligible to submit implementation plans under section 309 as an alternative method of achieving reasonable progress for Class I areas that were covered by the GCVTC's analysis—i.e., the 16 Class I areas on the Colorado Plateau. In order for States and Tribes to be able to utilize this section, however, the rule provided that EPA must receive an ''Annex'' to

[7] The preamble to the RHR provides additional details about the deciview (64 FR 35714, 35725 July 1, 1999).

[8] The set of ''major stationary sources'' potentially subject to BART is listed in CAA section 169A(g)(7).

[9] CAA section 169(g)(4); 40 CFR 51.308(e)(1)(iv).

[10] 40 CFR 51.308(e)(1)(v). *See also* CAA section 302(k) (defining ''emission limitation'' as ''a requirement established by the State or the Administrator which limits the quantity, rate, or concentration of emissions of air pollutants on a continuous basis, *including any requirement relating to the operation or maintenance of a source to assure continuous emission reduction* * * *'') (emphasis added).

[11] *See* CAA section 110(a)(2) (requirements for SIPs).

the GCVTC's final recommendations. The purpose of the Annex was to provide the specific provisions needed to translate the GCVTC's general recommendations for stationary source $SO_2$ reductions into an enforceable regulatory program. The rule provided that such an Annex, meeting certain requirements, be submitted to EPA no later than October 1, 2000, see 40 CFR 51.309(d)(4) and 51.309(f). The Annex was submitted in 2000, and EPA revised 40 CFR 51.309 in 2003. See 68 FR 33764, June 5, 2003.

## V. SIP and FIP Background

### *A. History of State Submittals and EPA Actions*

Since four of its twelve mandatory Class I Federal areas are on the Colorado Plateau, Arizona had the option of submitting a Regional Haze SIP under section 309 of the Regional Haze Rule. A SIP that is approved by EPA as meeting all of the requirements of section 309 is ''deemed to comply with the requirements for reasonable progress with respect to the 16 Class I areas [on the Colorado Plateau] for the period from approval of the plan through 2018.'' 40 CFR 51.309(a). When these regulations were first promulgated, 309 submissions were due no later than December 31, 2003. Accordingly, the Arizona Department of Environmental Quality (ADEQ) submitted to EPA on December 23, 2003, a 309 SIP for Arizona's four Class I Areas on the Colorado Plateau. ADEQ submitted a revision to its 309 SIP, consisting of rules on emissions trading and smoke management, and a correction to the state's regional haze statutes, on December 31, 2004. EPA approved the smoke management rules submitted as part of the 2004 revisions, *see* 71 FR 28270 and 72 FR 25973, but did not propose or take final action on any other portion of the 309 SIP.

In response to an adverse court decision,[12] EPA revised 40 CFR 51.309 on October 13, 2006, making a number of substantive changes and requiring states to submit revised 309 SIPs by December 17, 2007. See 71 FR 60612. Subsequently, ADEQ sent a letter to EPA dated December 14, 2008, acknowledging that it had not submitted a SIP revision to address the requirements of 309(d)(4) related to stationary sources and 309(g), which governs reasonable progress requirements for Arizona's eight mandatory Class I areas outside of the Colorado Plateau.[13]

EPA made a finding on January 15, 2009, that 37 states, including Arizona, had failed to make all or part of the required SIP submissions to address regional haze. See 74 FR 2392. Specifically, EPA found that Arizona failed to submit the plan elements required by 40 CFR 309(d)(4) and (g). EPA sent a letter to ADEQ on January 14, 2009, notifying the state of this failure to submit a complete SIP. ADEQ later decided to submit a SIP under section 308, instead of section 309.

ADEQ adopted and transmitted its Regional Haze SIP under Section 308 of the Regional Haze Rule (''Arizona Regional Haze SIP'') to EPA Region 9 in a letter dated February 28, 2011. The plan was determined complete by operation of law on August 28, 2011.[14] The SIP was properly noticed by the State and available for public comment for 30 days prior to a public hearing held in Phoenix, Arizona, on December 2, 2010. Arizona included in its SIP responses to written comments from EPA Region 9, the National Park Service, the U.S. Forest Service, and other stakeholders including regulated industries and environmental organizations. The Arizona Regional Haze SIP is available to review in the docket for the proposed rule.

### *B. EPA's Authority To Promulgate a FIP*

Under CAA section 110(c), EPA is required to promulgate a Federal Implementation Plan within two years of the effective date of a finding that a state has failed to make a required SIP submission. The FIP requirement is void if a state submits a regional haze SIP, and EPA approves that SIP within the two-year period. See 74 FR 2392, January 15, 2009. Specifically, CAA section 110(c) provides:

(1) The Administrator shall promulgate a Federal implementation plan at any time within 2 years after the Administrator—

(A) finds that a State has failed to make a required submission or finds that the plan or plan revision submitted by the State does not satisfy the minimum criteria established under [CAA section 110(k)(1)(A)], or

(B) disapproves a State implementation plan submission in whole or in part, unless the State corrects the deficiency, and the Administrator approves the plan or plan revision, before the Administrator promulgates such Federal implementation plan.

Section 302(y) defines the term ''Federal implementation plan'' in pertinent part, as:

> [A] plan (or portion thereof) promulgated by the Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a State implementation plan, and which includes enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions or emissions allowances).

Thus, because we determined that Arizona failed to timely submit a Regional Haze SIP, we are required to promulgate a Regional Haze FIP for Arizona, unless we first approve a SIP that corrects the non-submittal deficiencies identified in our finding of January 15, 2009. For the reasons explained below, we are proposing to partially approve and partially disapprove the Arizona Regional Haze SIP. Therefore, we are proposing a FIP to address those portions of the SIP that we are proposing to disapprove. If Arizona submits a SIP revision that addresses the deficiencies in sufficient time for EPA to review the submission, then we would prefer to act on that submittal, if such action is consistent with our obligations under the CAA and applicable court orders.

## VI. EPA's Evaluation of Arizona's BART Analyses and Determinations

### *A. Arizona's Identification of BART Sources*

*ADEQ's Analysis:* In the first step of the BART process, ADEQ identified all the BART-eligible sources within the jurisdiction of the State and local agencies, and applied the three eligibility criteria in the RHR (40 CFR 51.301) to these facilities. The criteria are: (1) One or more emission units at the facility are classified in one of the 26 industrial source categories listed in the BART Guidelines; (2) the emission unit(s) did not operate before August 7, 1962, but was in existence on August 7, 1977; and (3) the total potential to emit of any visibility impairing pollutant from the subject emission units is greater or equal to 250 tons per year. ADEQ determined that Apache, Cholla and Coronado have emissions units that meet these criteria.

In a second step, ADEQ identified those BART-eligible sources that may reasonably be anticipated to cause or contribute to visibility impairment at any Class I area. The BART Guidelines allow states to consider exempting some BART-eligible sources from BART review in the event that they may not

[12] *Center for Energy and Economic Development* v. *EPA,* 398 F.3d 653 (D.C. Circuit 2005).

[13] Letter from Stephen A. Owens, ADEQ, to Wayne Nastri, EPA (December 14, 2008).

[14] See CAA section 110(k)(1)(B).

reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. For states using modeling to determine the applicability of BART to single sources, the BART Guidelines note that the first step is to set a contribution threshold to assess whether the impact of a single source is sufficient to cause or contribute to visibility impairment at a Class I area. Further, the BART Guidelines state that, ''[a] single source that is responsible for a 1.0 deciview change or more should be considered to 'cause' visibility impairment.'' [15] The BART Guidelines also state that ''the appropriate threshold for determining whether a source contributes to visibility impairment' may reasonably differ across states,'' but, ''[a]s a general matter, any threshold that you use for determining whether a source 'contributes' to visibility impairment should not be higher than 0.5 deciviews.'' For determining whether a source is subject to BART, ADEQ used a contribution threshold of 0.50 dv.

The WRAP's Regional Modeling Center (RMC) developed a modeling protocol, entitled ''CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States.'' [16] The protocol specified the use of CALPUFF version 6.112 and CALMET version 6.211, which were the accepted model versions at the time.[17] The WRAP RMC used this protocol to perform CALPUFF modeling for each of the western states. ADEQ then relied on the RMC's modeling to assess the potential of BART-eligible sources to cause or contribute to Class I visibility impairment. The visibility impacts of AEPCO Apache Generating Station, APS Cholla Power Plant, and SRP Coronado Generating Station are each well above the 0.5 dv ''contribution'' threshold as well as the 1.0 dv ''causation'' threshold.[18] As a result, ADEQ determined that emissions units at the Apache, Cholla, and Coronado facilities are subject to BART as listed in Table 2.

TABLE 2—SOURCES SUBJECT TO BART

| Facility | BART emission units | Source category | Pollutants evaluated | WRAP modeled impact [a] |
|---|---|---|---|---|
| AEPCO Apache Generating Station. | Units 1, 2, and 3 | Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input. | $NO_X$, $SO_2$, $PM_{10}$ | 1.95 dv |
| APS Cholla Power Plant | Units 2, 3, and 4 | ........................................ | $NO_X$, $SO_2$, $PM_{10}$ | 2.88 dv |
| SRP Coronado Generating Station. | Units 1 and 2 | ........................................ | $NO_X$, $SO_2$, $PM_{10}$ | 3.32 dv |

[a] Average of the 98th percentile across 2001, 2002 and 2003 for the most affected Class I Area.

*EPA's Evaluation:* We are proposing to approve ADEQ's determination that Apache, Cholla, and Coronado are eligible for and subject to a BART control analysis. Each of the three facilities addressed in this notice (Apache, Cholla and Coronado) agreed with ADEQ's determination that they are subject to BART. While we do not agree with all aspects of the process by which ADEQ identified its eligible-for-BART and subject-to-BART sources, we do agree with ADEQ that the three facilities in this notice are eligible for and subject to BART. Since our action today focuses on only the three facilities, we will address ADEQ's other subject-to-BART determinations in a separate action at a later date.

*B. Arizona's BART Control Analysis*

The third step of the BART evaluation is to perform a five-factor BART analysis as the basis for making a BART control determination. In performing this analysis, 40 CFR 51.308(e)(1)(ii)(A) requires that states consider the following factors on a pollutant-by-pollutant basis: (1) The costs of compliance of each technically feasible control technology, (2) the energy and non-air quality environmental impacts of compliance of the control technologies, (3) any existing pollution control technology in use at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. These factors are frequently referred to as the ''five-factor analysis'' for the RHR BART determination.

The BART Guidelines recommend that a BART analysis include the following five steps. The Guidelines provide detailed instructions on how to perform each of these steps.[19]

- Step 1—Identify All Available Retrofit Control Technologies,
- Step 2—Eliminate Technically Infeasible Options,
- Step 3—Evaluate Control Effectiveness of Remaining Control Technologies,
- Step 4—Evaluate Impacts and Document the Results,[20] and
- Step 5—Evaluate Visibility Impacts.

*ADEQ's Analysis:* ADEQ's BART analyses mostly followed this approach, with the addition of a step to identify existing control technologies and a step concluding ''selection of BART.'' [21] Thus, ADEQ's analyses included the following seven steps:

- Step 1: Identify the Existing Control Technologies in Use at the Source
- Step 2: Identify All Available Retrofit Control Options
- Step 3: Eliminate All Technically Infeasible Control Options
- Step 4: Evaluate Control Effectiveness of Remaining Technologies
- Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results [22]
- Step 6: Evaluate Visibility Impacts
- Step 7: Select BART

*EPA's Evaluation:* We find that this overall approach to the five-factor analysis is generally reasonable and consistent with the RHR and the BART Guidelines. With respect to the three

[15] 70 FR 39104, 39161, July 6, 2005.

[16] See Docket Item B–15.

[17] EPA subsequently required the uses of CALPUFF and CALMET version 5.8 for new modeling applications. However, EPA is accepting BART modeling performed according to a previously approved protocol, as was the case for the WRAP protocol.

[18] See Docket Item No. B–12. Visibility impacts as listed in ''Summary of WRAP RMC BART Modeling for Arizona'' Draft No. 5, May 7, 2005. Initial draft released on April 4, 2005.

[19] 40 CFR part 51, appendix Y, § IV.D.

[20] Step 4 includes evaluating the cost of compliance, energy impacts, non-air quality environmental impacts, and remaining useful life.

[21] Arizona Regional Haze SIP, pp. 138–143.

[22] We note that, while ADEQ refers to its Step 5 as an evaluation of energy and non-air quality environmental impacts, this step also includes consideration of the costs of compliance and the remaining useful life of the source, consistent with the BART Guidelines, 40 CFR part 51, appendix Y, § IV.D.4.

sources covered by this action, we find that ADEQ's implementation of the first four steps of its approach is generally reasonable and consistent with the RHR and the BART Guidelines. However, we do not agree with ADEQ's analysis in steps 5 through 7.[23] In particular, under step 5, we find that the costs of control were not calculated in accordance with the BART Guidelines; under step 6, we find that the visibility impacts were not appropriately evaluated and considered; and under step 7, we find that ADEQ did not provide a sufficient explanation and rationale for its determinations. While we find these problems in all of ADEQ's BART analyses for the three sources, they do not appear to have had a substantive impact on ADEQ's selection of controls for $SO_2$ and $PM_{10}$. With respect to ADEQ's $NO_X$ BART determinations, however, we find that these problems resulted in control determinations that are inconsistent with the RHR and the BART Guidelines. We summarize below how ADEQ applied the five factors and identify a number of issues common to the three relevant sources.

1. Cost of Compliance

ADEQ included information relating to costs of compliance in its RH SIP, including information on total annualized costs, cost per ton of pollutant removed, and incremental cost per ton of pollutant removed for the various control options considered. Cost calculations were prepared by consulting firms on behalf of the facilities as part of their BART analyses that relied on a combination of vendor quotes, facility data, and internal cost calculation methodology. These BART analyses were subsequently submitted to ADEQ. Upon review, ADEQ requested certain clarifying information from the facilities regarding these cost calculations, including greater detail on the underlying assumptions and additional supporting documentation. ADEQ received responses of varying detail to these requests, and included this information as part of its RH SIP. As described in further detail in the discussion of each facility, there are certain aspects of these cost calculations that we find inconsistent with the BART Guidelines and EPA's Control Cost Manual. We also disagree with the manner in which ADEQ interpreted the cost-related information included in its RH SIP.

2. Energy and Non-Air Quality Environmental Impacts

In its BART analyses, ADEQ identified only minor energy and non-air quality impacts for $SO_2$ or $PM_{10}$ control strategies. Regarding $NO_X$ emissions, ADEQ's BART analyses point out that the various control options will incur increased energy usage by any electric generating unit (EGU) where they are installed. In particular, Selective Catalytic Reduction (SCR) retrofit will cause an additional pressure drop in the flue gas system due to the catalyst, increasing power requirements. Additionally, ADEQ's SIP submission asserts that ammonia levels in fly ash due to Selective Non-catalytic Reduction (SNCR) and SCR installations could affect the decision of facility managers to sell or dispose of fly ash.[24] Finally, the Arizona SIP notes that SNCR and SCR may involve potential safety hazards associated with the transportation and handling of anhydrous ammonia.[25] However, ADEQ did not cite any of these potential energy and non-air impacts as the basis for eliminating any otherwise feasible control strategies for $NO_X$. EPA concurs that these impacts do not warrant elimination of any of the control options.

3. Existing Pollution Control Technology

The presence of existing pollution control technology is reflected in the BART analysis in two ways: First, in the consideration of available control technologies (step 1 of ADEQ's analysis), and second, in the development of baseline emission rates for use in cost calculations and visibility modeling (steps 5 and 6 of ADEQ's analysis). As described in greater detail in the discussion for each facility, AEPCO, APS, and SRP used baseline time periods that varied from 2001 to 2007. The respective baseline emissions and existing pollution control technology used in the BART analyses reflect the levels of control in place at the time. EPA considers ADEQ's approach to be reasonable and generally consistent with the RHR and the BART Guidelines.

4. Remaining Useful Life of the Source

The remaining useful life of the source is usually considered as a quantitative factor in estimating the cost of compliance. With the exception of Apache Generating Station Unit 1, ADEQ used the default 20-year amortization period in the EPA Cost Control Manual as the remaining useful life of the facilities in its RH SIP. Without commitments for an early shut down of an EGU, it is not appropriate to consider a shorter amortization period in a BART analysis.

5. Degree of Visibility Improvement

ADEQ assessed the degree of improvement in visibility from candidate BART technologies using models and procedures generally in accord with EPA guidance. ADEQ relied on visibility analysis performed by the facilities, which used the WRAP RMC's modeling protocol. However, ADEQ's use of the modeling results in making BART decisions is problematic in several respects. First, ADEQ appears to have considered the visibility benefit of controls at only a single Class I area for each facility, even though there are nine to seventeen Class I areas nearby, depending on the facility. Since the facilities' modeling results indicated that controls would contribute to visibility improvement in multiple Class I areas, consideration of the benefits in additional areas is warranted. Although the RHR and the BART Guidelines do not prescribe a particular approach to calculating or considering visibility benefits across multiple Class I areas, overlooking significant visibility benefits at additional areas considerably understates the overall benefit of controls to improve visibility. A more complete assessment of the degree of visibility improvement for candidate BART controls would include consideration of the number of areas affected and the degree of visibility improvement expected in all areas. One could conduct this type of analysis by summing the benefits over the areas, or by some other quantitative or qualitative procedure.[26] The procedure followed by ADEQ is not a sufficient basis for making BART determinations for sources with substantial benefits across many Class I areas.

Second, ADEQ appears to have considered benefits from controls on only one emitting unit at a time. However, because the plumes from individual units overlap more or less completely by the time they reach a

[23] We do not believe that ADEQ appropriately used ''the most stringent emission control level that the technology is capable of achieving'' for SCR per the BART Guidelines at 40 CFR part 51, appendix Y, § IV.D.3. This issue is addressed on a source-by-source basis under the cost and visibility factors of our evaluation in section VI.C.

[24] Arizona Regional Haze SIP, Appendix D, p. 63.

[25] See, e.g. *id.* p. 53.

[26] Note that the issue here is not whether an individual in a given time and place would perceive the deciview benefits occurring at different Class I areas and under possibly different meteorological conditions. Rather, the issue is accounting in some way for the full set of expected visibility benefits. A national program for addressing regional haze must inherently address the multiple areas that occur in a region.

Class I area, the visibility benefits from controls on multiple units would be approximately additive. This issue of additive unit benefits could be addressed in some way without modeling all the units together, but ADEQ does not appear to have done this, and therefore underestimated the degree of visibility improvement from controls.

Finally, the ammonia background concentration assumed for Cholla and Coronado may be too low, ranging from 1 ppb to as low as 0.2 ppb. Nitrogen oxides and $SO_2$ emissions affect visibility after chemically transforming into particulate ammonium nitrate and ammonium sulfate, respectively. This process is limited by the amount of ammonia present, so modeling with a low assumed ammonia background may underestimate visibility impacts and thus the visibility benefit of controls. Ambient ammonia measurements for use as input to modeling are scarce, and measurements that include it in the form of ammonium even scarcer. In the absence of compelling ammonia background estimates, EPA guidance recommends the use of a 1 ppb ammonia background for areas in the west.[27]

### *C. Arizona's BART Determinations*

Our evaluation of ADEQ's BART determinations is organized by source, unit and pollutant with a focus on the cost and visibility factors of the BART analysis. A summary of the State's BART determinations for the three sources is in Table 3. ADEQ's BART determinations for $NO_X$ consist of combustion controls, either in the form of low-$NO_X$ burners (LNB) with flue gas recirculation (FGR), or LNB with overfire air (OFA) or separated overfire air (SOFA). For $PM_{10}$, ADEQ's BART determinations consist of fuel switching to pipeline natural gas (PNG) for Apache Unit 1, and add-on particulate controls such as electrostatic precipitators (ESPs) or fabric filters for the remaining units. For $SO_2$, ADEQ's BART determinations consist of fuel-switching to PNG for Apache Unit 1, and wet flue gas desulfurization (FGD) systems that are either already in place or planned for the remaining units.

TABLE 3—SUMMARY OF ARIZONA'S BART DETERMINATIONS

| Unit | Size (MW) | Fuel | $NO_X$ | | $PM_{10}$ | | $SO_2$ | |
|---|---|---|---|---|---|---|---|---|
| | | | Control technology | Emission limit * | Control technology | Emission limit * | Control technology | Emission limit * |
| Apache 1 | 75 | Natural Gas | LNB w/FGR, PNG use | 0.056 | PNG use | 0.0075 | PNG use | 0.00064 |
| Apache 2 | 195 | Coal | LNB w/OFA | 0.31 | ESP (upgraded) | 0.03 | Wet FGD (existing) | 0.15 |
| Apache 3 | 195 | Coal | LNB w/OFA | 0.31 | ESP (upgraded) | 0.03 | Wet FGD (existing) | 0.15 |
| Cholla 2 | 305 | Coal | LNB w/SOFA | 0.22 | Fabric filter | 0.015 | Wet FGD (existing) | 0.15 |
| Cholla 3 | 305 | Coal | LNB w/SOFA | 0.22 | Fabric filter (existing) | 0.015 | Wet FGD (existing) | 0.15 |
| Cholla 4 | 425 | Coal | LNB w/SOFA | 0.22 | Fabric filter (existing) | 0.015 | Wet FGD (existing) | 0.15 |
| Coronado 1 | 411 | Coal | LNB w/OFA | 0.32 | Hot-side ESP | 0.03 | Wet FGD (per Consent Decree). | 0.08 |
| Coronado 2 | 411 | Coal | LNB w/OFA | 0.32 | Hot-side ESP | 0.03 | Wet FGD (per Consent Decree). | 0.08 |

* Emission limits are in lb/MMBtu.

#### 1. Apache Unit 1

Apache Generating Station (Apache) consists of seven EGUs with a total plant-wide generating capacity of 560 megawatts. Unit 1 is a wall-fired boiler with a net unit output of 85 MW that burns pipeline-quality natural gas as its primary fuel, but also has the capability to use No. 2 through No. 6 fuel oils. At present, no emissions control equipment is installed on Unit 1. ADEQ's BART analyses for Apache Unit 1 relied largely on data and analyses provided by AEPCO and its contractor. These data and analyses are summarized below, along with ADEQ's determinations for each pollutant and EPA's evaluations of these analyses and determinations.

##### a. BART for $NO_X$

*ADEQ's Analysis:* Unit 1 currently operates with no $NO_X$ controls. In its BART analysis submitted to ADEQ, AEPCO developed baseline emissions for multiple fuel-use scenarios including natural gas, and No. 2 and No. 6 fuel oil usage. Baseline natural gas emissions were based on the highest 75 percent load 24-hour $NO_X$ emission levels reported in EPA's Acid Rain Database for 2006. Since the only fuel burned in 2006 was natural gas, baseline emissions for No. 2 or No. 6 fuel oil usage could not be developed based on data from 2006. As a simplifying assumption, baseline No. 2 fuel oil $NO_X$ emissions were assumed to be equal to natural gas usage. Baseline emissions for No. 6 fuel oil usage were estimated using AP–42 emission factors.[28] A summary of baseline emissions for various fuels is provided in Table 4.

TABLE 4—APACHE UNIT 1: ARIZONA'S BASELINE EMISSION FACTORS [a]

| Pollutant | Natural Gas (lb/MMBtu) | No. 2 Fuel oil | No. 6 fuel oil |
|---|---|---|---|
| $NO_X$ | 0.147 | 0.147 | 0.301 |
| $PM_{10}$ | 0.0075 | 0.014 | 0.0737 |
| $SO_2$ | 0.00064 | 0.051 | 0.906 |

[a] See Docket Item B–02 (Table 3–1 of AEPCO Apache 1 BART Analysis).

[27] 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*.

[28] See Docket Item B–2. Page 2–1 of AEPCO Apache 1 BART Analysis.

AEPCO examined multiple control technologies and options for Apache Unit 1, including combustion controls, post combustion add-on controls, and fuel-switching. A summary of cost of compliance and degree of visibility improvement for these options is in Table 5. These cost and visibility improvement values are based on baseline and control case emissions corresponding to No. 6 fuel oil usage, which of the three fuels considered is the fuel type that generates the greatest $NO_X$ emissions.

TABLE 5—APACHE UNIT 1: ARIZONA'S COST AND VISIBILITY ANALYSIS FOR $NO_X$

| Control option [b] | Emission rate (lb/MMBtu) | Emissions removed (tons/yr) | Annualized cost ($/year) | Cost-effectiveness [d] ($/ton) | | Visibility Improvement [c] (dv) | |
|---|---|---|---|---|---|---|---|
| | | | | Average | Incremental (from previous) | Total (from base case) | Incremental (from previous) |
| Baseline | 0.301 | | | | | | |
| LNB + FGR | 0.15 | 297 | 551,982 | 1,859 | | 0.194 | |
| ROFA | 0.16 | 278 | 939,093 | 3,378 | −20,374 | 0.256 | 0.062 |
| SNCR with LNB + FGR | 0.11 | 376 | 1,079,389 | 2,871 | 1,432 | 0.24 | −0.016 |
| ROFA w/Rotamix | 0.11 | 376 | 1,505,825 | 4,005 | [a] NA | 0.24 | [a] NA |
| SCR with LNB + FGR | 0.07 | 455 | 5,704,798 | 12,538 | 53,152 | 0.409 | 0.169 |

[a] The previous option, SNCR with LNB + FGR has the same emission rate, making an incremental comparison invalid.
[b] Per ADEQ's and AEPCO's analyses, control options are ranked here by cost, not by emission rate
[c] Visibility improvement at Chiricahua Wilderness Area, the Class I area exhibiting the highest impact
[d] Cost-effectiveness values obtained from Table 10.3, Appendix D (TSD) of Arizona RH SIP. See Docket Item B–01.

In its cost calculations for Apache Unit 1, AEPCO used a capital recovery factor based on a 7.10 percent interest rate, and a plant remaining useful life of eight years.[29] The plant's remaining useful life was based upon Apache Unit 1 operating until 2021, and an assumed BART implementation date of 2013.[30] AEPCO eliminated many control options, including SCR, based on high cost-effectiveness ($/ton), and primarily examined the LNB w/FGR and ROFA control options. AEPCO noted that LNB with FGR resulted in larger incremental visibility improvement than ROFA, and proposed LNB with FGR, burning either natural gas or fuel oil, as BART for $NO_X$ at Apache Unit 1.

In order to evaluate AEPCO's BART analysis, ADEQ requested supporting information explaining assumptions used in the economic analysis, baseline emissions, and control technology options. Based on this additional information, as well as on AEPCO's original analysis, ADEQ accepted the company's proposed BART recommendation of LNB with FGR for Unit 1, but added a fuel restriction to allow only the use of natural gas. This determination corresponds to a BART emission limit for $NO_X$ at Apache Unit 1 of 0.056 lb/MMBtu.[31]

*EPA's Evaluation:* We disagree with multiple aspects of the analysis for Apache Unit 1. We consider the use of eight years for the plant's remaining useful life in the control cost calculations as unjustified in the absence of documentation that the unit will shut down in 2021. We also note that control cost calculations include costs that are disallowed by EPA's Control Cost Manual, such as owner's costs and AFUDC. Both of these elements have the effect of inflating cost calculations and thus the cost-effectiveness of the various control options considered. In addition, we do not consider using identical baseline emissions for No. 2 fuel oil and natural gas appropriate, although this likely did not affect either AEPCO's or ADEQ's BART determination, which was informed primarily by emission estimates based on No. 6 fuel oil, the highest emitting fuel.

By including a natural gas-only fuel restriction, ADEQ's BART determination of LNB with FGR results in a $NO_X$ emissions limit of 0.056 lb/MMBtu, which is more stringent than any of the control options that AEPCO and ADEQ considered in conjunction with No. 6 or No. 2 fuel oil. Neither AEPCO's nor ADEQ's analysis, however, included visibility modeling for control options on a natural gas-only basis. The absence of such information does not allow us to fully evaluate if options more stringent than LNB with FGR are appropriate on a natural gas-only basis. Nevertheless, we are proposing to approve ADEQ's $NO_X$ BART determination of LNB with FGR (natural gas usage only) with an emission limit of 0.056 lb/MMBtu for Apache Unit 1.

b. BART for $PM_{10}$

*ADEQ's Analysis:* Apache Unit 1 currently operates with no $PM_{10}$ controls. In its BART analysis submitted to ADEQ, AEPCO developed baseline emissions for multiple fuel use scenarios including natural gas, and No. 2 and No. 6 fuel oil usage. Baseline $PM_{10}$ emissions for all fuels were calculated based on AP–42 emission factors.[32] A summary of these emissions is in Table 4.

AEPCO examined multiple control options for $PM_{10}$ at Apache Unit 1, including add-on controls and fuel switching. A summary of cost of compliance and degree of visibility improvement for these options is summarized in Table 6. These cost and visibility improvement values are based on baseline and control case emissions corresponding to No. 6 fuel oil usage, which of the three fuels considered generates the greatest $PM_{10}$ emissions. In its BART analysis, AEPCO cited high costs of compliance and minimal visibility improvements for the $PM_{10}$ control options, and proposed no $PM_{10}$ controls as BART for $PM_{10}$, using either natural gas or No. 2 fuel oil. Based on the data and analysis provided by AEPCO, ADEQ determined that BART for $PM_{10}$ at Apache Unit 1 is no additional controls, but also determined that a fuel restriction to allow only the use of natural gas was appropriate. This corresponds to a $PM_{10}$ BART emission

[29] See Docket Item B–02. Appendix A (Economic Analysis) of AEPCO Apache 1 BART Analysis.

[30] See Docket Item B–02. Page 2–1 of AEPCO Apache 1 BART Analysis.

[31] See Docket Item B–01. Emission rate as specified in Table 10.2, Appendix D (Technical Support Document) of Arizona Regional Haze SIP.

[32] See Docket Item B–02, Page 2–1 of AEPCO Apache 1 BART Analysis.

limit for Apache Unit 1 of 0.0075 lb/MMBtu.[33]

TABLE 6—APACHE UNIT 1: ARIZONA'S COST AND VISIBILITY ANALYSIS FOR $PM_{10}$

| Control option | Emission rate (lb/MMBtu) | Emissions removed (tons/yr) | Annualized cost ($/year) | Cost-effectiveness [a] ($/ton) | | Visibility Improvement [b] (dv) | |
|---|---|---|---|---|---|---|---|
| | | | | Average | Incremental (from previous) | Total (from base case) | Incremental (from previous) |
| Baseline | 0.0737 | | | | | | |
| Fabric Filter | 0.015 | 116 | 3,615,938 | 31,172 | | 0.010 | |
| Fuel switch to PNG | 0.0075 | | 0 | | | | |

[a] Cost-effectiveness values as reported in Table 10.6, Appendix D (TSD) of Arizona RH SIP. See Docket Item B–01.
[b] As summarized in Table 5–12, AEPCO Apache 1 BART Analysis. See Docket Item B–02. Visibility improvement at Chiricahua Wilderness Area, the Class I area exhibiting the highest impact.

*EPA's Evaluation:* ADEQ's $PM_{10}$ analysis includes many of the same issues we noted in its $NO_X$ analysis, including the use of an eight-year plant remaining useful life, and inclusion of costs that are disallowed by EPA's Control Cost Manual. Although we do not agree with elements of ADEQ's $PM_{10}$ BART analysis for Apache Unit 1, we find that its conclusion is reasonable, given the small visibility improvement projected to result from $PM_{10}$ reductions at this Unit. Thus, we are proposing to approve ADEQ's $PM_{10}$ BART determination for Apache Unit 1.

c. BART for $SO_2$

*ADEQ's Analysis:* Apache Unit 1 currently operates with no $SO_2$ controls. In its BART analysis submitted to ADEQ, AEPCO developed baseline emissions for multiple fuel use scenarios including natural gas, and No. 2 and No. 6 fuel oil. Baseline natural gas emissions were based upon the highest 75 percent load 24-hour $SO_2$ emission levels reported in EPA's Acid Rain Database for 2006. Since the only fuel burned in 2006 was natural gas, baseline emissions for No. 2 or No. 6 fuel oil usage could not be developed based on data from 2006. Baseline emissions for No. 2 and No. 6 fuel oil usage were estimated using AP–42 emission factors.[34] A summary of these emissions is summarized in Table 4.

AEPCO also examined multiple control options for $SO_2$ on Apache 1, including add-on controls and fuel-switching. A summary of cost of compliance and degree of visibility improvement for these options is summarized in Table 7. These cost and visibility improvement values are from baseline and control case emissions corresponding to No. 6 fuel oil usage, which is the fuel type that generates the greatest $SO_2$ emissions. In its BART analysis, AEPCO cited high costs of compliance and minimal visibility improvements for the $SO_2$ control options, and proposed no additional $SO_2$ controls, using either natural gas or No. 2 fuel oil, as BART for $SO_2$. ADEQ determined that BART for $SO_2$ is no additional controls, but added a fuel restriction to allow only the use of natural gas. This corresponds to an $SO_2$ BART emission limit for Apache Unit 1 of 0.00064 lb/MMBtu.[35]

TABLE 7—APACHE UNIT 1: ARIZONA'S COST AND VISIBILITY ANALYSIS FOR $SO_2$

| Control option | Emission rate (lb/MMBtu) | Emissions removed (tons/yr) | Annualized cost ($/year) | Cost-effectiveness [a] ($/ton) | | Visibility Improvement [b] (dv) | |
|---|---|---|---|---|---|---|---|
| | | | | Average | Incremental (from previous) | Total (from base case) | Incremental (from previous) |
| Baseline | 0.906 | | | | | | |
| Fuel switch to low-sulfur fuel oil | 0.051 | | | | | | |
| Spray dryer absorber (dry FGD) [1] | 0.10 | 1,587 | 3,881,706 | 2,446 | | 0.765 | |
| Fuel switch to PNG | 0.00064 | | 0 | | | | |

[a] Cost-effectiveness values as reported in Table 10.8, Appendix D (TSD) of Arizona RH SIP. See Docket Item B–01.
[b] As summarized in Table 5–12, AEPCO Apache 1 BART Analysis. See Docket Item B–02. Visibility improvement at Chiricahua Wilderness Area, the Class I area exhibiting the highest impact.

*EPA's Evaluation:* The $SO_2$ analysis includes many of the same issues we noted in the $NO_X$ analysis, including the use of an eight-year plant remaining useful life, and inclusion of costs that are disallowed by EPA's Control Cost Manual. ADEQ's BART determination, requiring the use of only natural gas, results in an $SO_2$ emission limit of 0.00064 lb/MMBtu. This emission rate is more stringent than any of the control options that ADEQ considered in conjunction with No. 6 fuel oil. We are proposing to approve ADEQ's BART determination for $SO_2$ as an emission limit of 0.00064 lb/MMBtu at Apache Unit 1.

2. Apache Units 2 and 3

Apache Units 2 and 3 are both dry-bottom, Riley Stoker turbo-fired boilers, each with a gross unit output of 204 MW. Both units are BART-eligible and are coal-fired boilers operating on sub-bituminous coal. Although there are physical differences between the two units, ADEQ found that the overall

[33] See Docket Item B–01. Emission rate as specified in Table 10.5, Appendix D (Technical Support Document) of Arizona Regional Haze SIP.

[34] See Docket Item B–02. Page 2–2 of AEPCO Apache 1 BART Analysis.

[35] See Docket Item B–01. Emission rate as specified in Table 10.7, Appendix D (Technical Support Document) of Arizona Regional Haze SIP.

differences are minimal and therefore considered both units together in its BART analysis. As with Apache Unit 1, ADEQ's analysis relied largely on information provided by AEPCO and its contractor. This information is summarized below, along with ADEQ's determinations for each pollutant and EPA's evaluation.

While the following sections describe both ADEQ's and EPA's evaluations based on the information in the record, we note that we received additional information from AEPCO on June 29, 2012, related to the potential adverse impacts of the affordability of $NO_X$ controls. AEPCO states that affordability is affected by its small size, the low income profiles of AEPCO's service area, and AEPCO's ability to access financing. While this information came in too late to be evaluated as part of this proposed rulemaking, EPA has put the information in the docket and will evaluate it during the public comment period.[36]

a. BART for $NO_X$

*ADEQ's Analysis:* AEPCO developed baseline $NO_X$ emissions by examining the average $NO_X$ emissions from 2002 to 2007, a time period in which both units were equipped with OFA as $NO_X$ emission controls.[37] AEPCO examined several $NO_X$ control technologies, including combustion controls and add-on post-combustion controls. A summary of Arizona's costs of compliance and visibility impacts associated with these options is presented in Table 8. ADEQ relied on this information from the facility to develop its RH SIP.[38] Estimates of control technology emission rates were developed based on a combination of vendor quotes, contractor information, and internal AEPCO information regarding environmental upgrades.[39] Annual emission reductions were calculated based on the emission rate estimates combined with annual capacity factors as specified by AEPCO.[40] Control costs were developed based on a combination of vendor quotes and contractor information. These cost calculations provided line item summaries of capital costs and annual operating costs, but did not include further supporting information such as detailed equipment lists, vendor quotes, or the design basis for line item costs.

TABLE 8—APACHE UNITS 2 AND 3: ARIZONA'S COST AND VISIBILITY SUMMARY

| Control option | Emission rate (lb/MMBtu) | Emissions removed (tons/yr) | Annualized cost ($/year) | Cost-effectiveness ($/ton) | | Visibility improvement[a] (deciviews) | | Cost per total deciview improvement ($/dv) |
|---|---|---|---|---|---|---|---|---|
| | | | | Average | Incremental (from previous) | Total (from baseline) | Incremental (from previous) | |
| **Apache Unit 2** | | | | | | | | |
| OFA (baseline) | 0.47 | | | | | | | |
| LNB + OFA | 0.31 | 1,305 | $533,000 | $408 | | 0.267 | | $1,996,000 |
| ROFA | 0.26 | 1,710 | 1,664,000 | 973 | 305 | 0.359 | 0.092 | 4,636,000 |
| SNCR + LNB + OFA | 0.23 | 1,953 | 1,738,000 | 890 | 1,860 | 0.416 | 0.057 | 4,532,000 |
| ROFA w/Rotamix | 0.18 | 2,358 | 2,225,000 | 944 | 866 | 0.491 | 0.075 | 4,177,000 |
| SCR + LNB + OFA | 0.07 | 3,250 | 6,102,000 | 1,878 | 4,346 | 0.676 | 0.185 | 9,028,000 |
| **Apache Unit 3** | | | | | | | | |
| OFA (baseline) | 0.43 | | | | | | | |
| LNB + OFA | 0.31 | 926 | 532,808 | 575 | | 0.206 | | 2,586,000 |
| ROFA | 0.26 | 1,312 | 1,643,241 | 1,252 | 322 | 0.298 | 0.092 | 5,484,000 |
| SNCR + LNB + OFA | 0.23 | 1,543 | 1,717,633 | 1,113 | 1,920 | 0.356 | 0.058 | 5,004,000 |
| ROFA w/Rotamix | 0.18 | 1,929 | 2,181,833 | 1,131 | 873 | 0.436 | 0.080 | 4,825,000 |
| SCR + LNB + OFA | 0.07 | 2,778 | 6,062,301 | 2,182 | 4,571 | 0.633 | 0.197 | 9,577,000 |

[a] At the Class I area exhibiting the greatest baseline visibility impact, Chiricahua Wilderness Area.

Regarding visibility impacts, ADEQ relied on visibility modeling submitted by AEPCO to evaluate the visibility improvement attributable to each of the $NO_X$ control technologies that it considered. This visibility modeling was performed using three years of meteorological data (2001 to 2003), and was generally performed in accordance with the WRAP modeling protocol. The average of the three 98th percentiles from the modeled years 2001 to 2003 was used as the visibility metric for each emission scenario and Class I area. For assessing the degree of visibility improvement, ADEQ considered only the visibility benefits at the area with the highest base case (pre-control) impact: Chiricahua National Monument and Chiricahua Wilderness Area (two nearby Class I areas served by one air monitor). For each control, ADEQ listed visibility improvement in deciviews, and cost in millions of dollars per deciview improvement.[41] Results are comparable for both units, with Unit 2 showing somewhat higher visibility benefits and somewhat lower cost per improvement than Unit 3. Unit 2 visibility improvements range from 0.27 dv for LNB to 0.68 dv for SCR, while the costs per deciview range from $2 million for LNB to over $9 million for SCR. ADEQ concluded that LNBs with the existing OFA systems represent BART for Units 2 and 3, though no explicit reasoning is provided for the selection.

ADEQ determined that LNB plus OFA constitute BART for $NO_X$ at Apache Units 2 and 3. In making this determination, ADEQ did not provide adequate information regarding its rationale or weighing of the five factors. ADEQ stated only that ''(A)fter reviewing the company's BART analysis, and based upon the information above, ADEQ has

[36] See Docket Item C–16, Letter from Michelle Freeark (AEPCO) to Deborah Jordan (EPA), AEPCO's Comments on BART for Apache Generating Station, June 29, 2012.

[37] See Docket Item B–03 and B–04, AEPCO Apache BART Analyses, page 2–2.

[38] See Docket Item B–03 and B–04, AEPCO Apache BART Analyses. This information is also summarized in Docket Item B–01, Arizona Regional Haze SIP, Appendix D, Tables 10.10 through 10.13.

[39] As listed in Table 3–2, Docket Items B–03 and B–04, AEPCO Apache BART Analyses.

[40] As listed in Table 2–1, Docket Items B–03 and B–04. Annual capacity factors used for each unit are 92% (Apache 2), and 87% (Apache 3).

[41] Arizona SIP submittal, ''Appendix D: Arizona BART—Supplemental Information'', p. 65.

determined that, for Units 2 and 3 BART for $NO_X$ is new LNBs and the existing OFA system with a $NO_X$ emissions limit of 0.31 lb/MMBtu * * *.'' [42]

*EPA's Evaluation:* We disagree with several aspects of the $NO_X$ BART analysis for Apache Units 2 and 3. The control cost calculations included line item costs not allowed by the EPA Control Cost Manual, such as owner's costs, surcharge, and AFUDC. Inclusion of these line items has the effect of inflating the total cost of compliance and the cost per ton of pollutant reduced.

Regarding visibility improvement as shown in Table 8, ADEQ chose LNB as BART, which provides the lowest visibility benefit of any of the controls modeled. By contrast, SCR would provide an improvement of more than 0.5 dv at a single Class I Area, and a substantial incremental benefit relative to the next more stringent control, ROFA-Rotamix. Multiple Class I areas have comparable benefits. The visibility benefits are larger than those listed, if both Units 2 and 3 are considered together. (See Table 17 below for EPA's visibility results.) The SCR cost per deciview of improvement is lower than those for Cholla and Coronado, as indicated below in their respective sections.

ADEQ provides little explicit reasoning about the visibility basis for the BART selection. For example, there is no weighing of visibility benefits and visibility cost-effectiveness for the various candidate controls and the various Class I areas. The modeling results show that controls more stringent than LNB appear to be needed to give substantial visibility benefits. Visibility impacts at eight nearby Class I areas were not considered, and the visibility benefits of simultaneous controls on both units were not considered. For these reasons, EPA believes that ADEQ gave insufficient consideration to the visibility benefits of the various $NO_X$ control options available at Apache Units 2 and 3.

In summary, we find that ADEQ has not provided an adequate justification for adopting LNB with OFA as the ''best'' level of control.[43] Although ADEQ has developed information regarding each of the five factors, there are problems in both its cost and visibility analyses as described above. Moreover, ADEQ's BART analysis does not explain how it weighed these factors. For example, ADEQ did not indicate whether or not it considered any cost thresholds to be reasonable or expensive in analyzing the costs of compliance for the various control options. We note that ADEQ has made similar $NO_X$ BART determinations of LNB with OFA at other facilities, such as Cholla Power Plant. Although ADEQ's BART determinations for these other facilities implied that cost of compliance was an important consideration, it does not provide a rationale for this selection of $NO_X$ BART.[44] Thus, we are proposing to disapprove ADEQ's BART determination for $NO_X$ at Apache Units 2 and 3, since it does not comply with 40 CFR 51.308(e)(1)(ii)(A).

b. BART for $PM_{10}$

*ADEQ's Analysis:* The existing $PM_{10}$ controls on Apache Units 2 and 3 are hot-side Electrostatic Precipitators (ESPs).[45] AEPCO and ADEQ considered three potential retrofit control options for $PM_{10}$:

- Performance upgrades to existing hot-side ESP,
- Replacement of current ESP with a fabric filter, and
- Installation of a polishing fabric filter after ESP.

ADEQ found that all of these options are technically feasible and estimated their associated emission rates as shown in Table 9.

TABLE 9—APACHE UNITS 2 AND 3: ARIZONA'S CONTROLS AND EMISSION RATES FOR $PM_{10}$

| Control technology | Expected $PM_{10}$ emission rate |
|---|---|
| ESP Upgrades | 0.03 lb/MMBtu. |
| Full Size Fabric Filter | 0.015 lb/MMBtu. |
| Polishing Fabric Filter | 0.015 lb/MMBtu. |

ADEQ found that a fabric filter, whether in addition to or as replacement for the ESP, would require additional energy, but did not identify any non-air environmental impacts from any of the three options. The cost of compliance and degree of visibility improvement for each of these options, as analyzed by ADEQ, are summarized in Tables 10 and 11.

TABLE 10—APACHE UNIT 2: ARIZONA'S CONTROL COST OF VISIBILITY REDUCTION FOR $PM_{10}$

| Control | Deciview reduction | Total annualized cost (million $) | Cost per deciview reduced (million $/dv) | Average cost ($/ton) |
|---|---|---|---|---|
| ESP Upgrades | Unknown | Unknown | Unknown | Unknown |
| Polishing Fabric Filter | 0.085 | $2.217 | $26.09 | $9,121 |
| Full Size Fabric Filter | 0.085 | 2.888 | 33.98 | 11,880 |

TABLE 11—APACHE UNIT 3: ARIZONA'S CONTROL COST OF VISIBILITY REDUCTION FOR $PM_{10}$

| Control | Deciview reduction | Total annualized cost (million $) | Cost per deciview reduced (million $/dv) | Average cost ($/ton) |
|---|---|---|---|---|
| ESP Upgrades | Unknown | Unknown | Unknown | Unknown |
| Polishing Fabric Filter | 0.094 | $2.192 | $23.32 | $9,471 |
| Full Size Fabric Filter | 0.094 | $2.869 | $30.52 | 12,390 |

[42] Docket Item B–01, Arizona Regional Haze SIP, Appendix D, Page 65.

[43] See BART Guidelines, § IV.E.2.

[44] We do note, however, that AEPCO does provide some additional analysis on this position in the Apache BART analyses it submitted to ADEQ. Aside from stating that it reviewed AEPCO's analysis, ADEQ did not specifically reference or include any aspects of AEPCO's analysis in the RH SIP. As a result, we are not assuming that ADEQ necessarily agrees with AEPCO's rationale, and have therefore not provided an evaluation of it.

[45] See Appendix D, pages 65–69 for ADEQ's BART Analysis for $PM_{10}$ at Apache Units 2 and 3. See AEPCO Apache Unit 2 BART Analysis.

Based on its analysis of the five BART factors, as summarized above, ADEQ found BART for $PM_{10}$ is upgrades to the existing ESP and a $PM_{10}$ emissions limit of 0.03 lb/MMBtu for Units 2 and 3. In particular, ADEQ referred to installation of a flue gas conditioning system, improvements to the scrubber bypass damper system, and implementation of programming optimization measures for ESP automatic voltage controls as potential upgrades. ADEQ also noted that ''$PM_{10}$ emissions will be measured by conducting EPA Method 201/202 tests.''

*EPA's Evaluation:* As noted above, AEPCO's and ADEQ's control cost calculations include costs that are disallowed by EPA's Control Cost Manual, such as owner's costs and AFUDC.[46] In addition, AEPCO's and ADEQ's analyses do not demonstrate that all potential upgrades to the existing ESP were fully evaluated. Nonetheless, based on the small visibility improvement associated with $PM_{10}$ reductions from these units (e.g., less than 0.1 dv improvement from the most stringent technology), we conclude that additional analyses of control options would not result in a different BART determination. As a result, we propose to approve ADEQ's $PM_{10}$ BART determination at Apache Units 2 and 3.

Finally, we are seeking comment on whether test methods other than EPA Method 201 and 202 [47] (chosen by ADEQ) should be allowed or required for establishing compliance with the $PM_{10}$ limits that we are approving. In particular, as explained below, use of SCR [48] at these units is expected to result in increased condensable particulate matter in the form of sulfuric acid mist ($H_2SO_4$). In effect, the emission limit would be more stringent than intended by ADEQ and would likely not be achievable in practice. In order to avoid this result, while still assuring proper operation of the particulate control devices, we are requesting on comment on whether to allow compliance with the $PM_{10}$ limit to be demonstrated using test methods that do not capture condensable particulate matter, namely EPA Methods 1 through 4 and Method 5 or Method 5e.[49] Method 201 is very rarely used for testing. The typical method used for filterable $PM_{10}$ is Method 201A, ''constant sampling rate procedure,'' which is similar to Method 201, but is much more practical to perform on a stack.

c. BART for $SO_2$

*ADEQ's Analysis:* Apache Units 2 and 3 currently have wet limestone scrubbers installed for $SO_2$ removal.[50] Under the BART Guidelines, a state is not required to evaluate the replacement of the current $SO_2$ controls if their removal efficiency is over 50 percent, but should consider cost-effective scrubber upgrades designed to improve the system's overall $SO_2$ removal efficiency. Relying upon the BART analysis submitted by AEPCO,[51] ADEQ found that the following potential upgrades to the scrubbers are technically feasible:

- Elimination of bypass reheat,
- Installation of liquid distribution rings,
- Installation of perforated trays,
- Use of organic acid additives,
- Improved or upgraded scrubber auxiliary system equipment, and
- Redesigned spray header or nozzle.

ADEQ found that any upgrades likely would not increase power consumption, but would increase scrubber waste disposal and makeup water requirements, and would reduce the stack gas temperature. These three factors are the normal outcome of treating more of the exhaust gas and removing more of the $SO_2$ (increased scrubber waste disposal) and should not be given much weight in selecting a BART emission limit. ADEQ also noted that AEPCO had already made the following upgrades to the scrubbers: Elimination of flue gas bypass; splitting the limestone feed to the absorber feed tank and tower sump; upgrade of the mist eliminator system; installation of suction screens at pump intakes; automation of pump drain valves, and replacement of scrubber packing with perforated stainless steel trays. In addition, AEPCO tried using dibasic acid additive, but found that it did not result in significantly higher $SO_2$ removal. ADEQ did not evaluate the cost or visibility impacts of any additional upgrades to the scrubbers, but determined that BART for $SO_2$ emissions was no new controls and an emission limit of 0.15 lb/MMBtu on a 30-day rolling average basis.

*EPA's Evaluation:* We are proposing to approve ADEQ's $SO_2$ BART determination for Apache Units 2 and 3. Although ADEQ has not demonstrated that it fully considered all cost effective scrubber upgrades, as recommended by the BART Guidelines, ADEQ conducted a five-factor BART analysis and its final $SO_2$ BART determination for Apache Units 2 and 3 is consistent with the presumptive BART limit of 0.15 lb/MMBtu for utility boilers.[52] We have no evidence that additional analysis would have resulted in a lower emission limit. Therefore, we are proposing to approve the $SO_2$ emission limit of 0.15 lb/MMBtu (30-day rolling average) for Apache Units 2 and 3.

However, we note that Apache can receive coal from a number of different mines that can have differing sulfur content and potential for $SO_2$ emissions.[53] Therefore, we are seeking comment on whether additional cost-effective scrubber upgrades are available that would warrant a lower emission limit. We are also requesting comment on whether requiring 90 percent control efficiency in addition to the lb/MMBtu limit would better assure proper operation of the upgraded scrubbers when burning some types of low-sulfur western coal. If we receive information establishing that a lower limit is achievable or that a control efficiency requirement is needed, then we may disapprove the $SO_2$ emissions limit set by ADEQ and promulgate a revised limit for one or both of these units.

3. Cholla Units 2, 3 and 4

Cholla Power Plant consists of four primarily coal-fired electricity generating units with a total plant-wide generating capacity of 1,150 megawatts. Unit 1 is a 125 MW tangentially-fired, dry-bottom boiler that is not BART-eligible. Units 2, 3 and 4 have capacities of 300 MW, 300 MW and 425 MW, respectively, and are tangentially-fired, dry-bottom boilers that are each BART-eligible. Based on information provided by APS, the Cholla units operate on a blend of bituminous and sub-bituminous rank coals from the Lee Ranch and El Segundo mines.[54]

a. BART for $NO_X$

*ADEQ's Analysis:* APS submitted a BART analysis to ADEQ in January 2008. At the time of submittal, Cholla Units 2, 3 and 4 were equipped with close-coupled overfire air (COFA) as $NO_X$ controls. APS developed baseline $NO_X$ emissions by examining the highest 24-hour average emissions from

[46] See AEPCO BART Analysis Technical Memorandum dated July 8, 2009, page 12.

[47] See 40 CFR part 51 Appendix M.

[48] EPA is proposing SCR as BART for all of the coal-fired units. See Section VII.

[49] See 40 CFR part 60 appendix A.

[50] See Arizona Regional Haze SIP, Appendix D, pages 69–71 for ADEQ's BART Analysis for $SO_2$ at Apache Units 2 and 3.

[51] See AEPCO Apache Unit 2 BART Analysis.

[52] See BART Guidelines § IV.E.4.

[53] See, e.g. Apache Unit 2 BART Analysis, Table 3–1.

[54] A copy of the coal contract, including obligation amounts and coal quality, can be found in Docket Item B–09, ''Additional APS Cholla BART response'', Appendix B.

2001 to 2003.[55] APS examined several $NO_X$ control technologies, including combustion controls and add-on post combustion controls. A summary of the costs of compliance and visibility impacts associated with these options is presented in Table 12.

TABLE 12—CHOLLA UNITS 2, 3, AND 4: ARIZONA'S COST AND VISIBILITY SUMMARY FOR $NO_X$

| Control option | Emission rate (lb/MMBtu) | Emissions removed (tons/yr) | Annualized cost ($/year) | Cost-effectiveness ($/ton) | | Visibility improvement [a] (deciviews) | | Cost per total deciview improvement ($/dv) |
|---|---|---|---|---|---|---|---|---|
| | | | | Average | Incremental (from previous) | Total (from baseline) | Incremental (from previous) | |
| **Cholla 2** | | | | | | | | |
| COFA (baseline) | 0.50 | | | | | | | |
| LNB + SOFA | 0.22 | 3,314 | $635,000 | $192 | | 0.187 | | $3,400,000 |
| SNCR + LNB + SOFA | 0.17 | 3,900 | 2,175,000 | 558 | 2,628 | 0.218 | 0.031 | 9,980,000 |
| ROFA | 0.16 | 4,017 | 2,297,000 | 572 | 1,043 | 0.232 | 0.014 | 9,900,000 |
| ROFA w/Rotamix | 0.12 | 4,485 | 3,384,000 | 755 | 2,323 | 0.261 | 0.029 | 12,970,000 |
| SCR + LNB + SOFA | 0.07 | 5,071 | 9,625,000 | 1,898 | 10,650 | 0.287 | 0.026 | 33,540,000 |
| **Cholla 3** | | | | | | | | |
| COFA (baseline) | 0.41 | | | | | | | |
| LNB + SOFA | 0.22 | 2,096 | 635,000 | 303 | | 0.13 | | 5,040,000 |
| SNCR + LNB + SOFA | 0.17 | 2,648 | 2,157,000 | 815 | 2,757 | 0.16 | 0.038 | 13,150,000 |
| ROFA | 0.16 | 2,758 | 2,243,000 | 813 | 782 | 0.17 | 0.005 | 13,270,000 |
| ROFA w/Rotamix | 0.12 | 3,200 | 3,308,000 | 1,034 | 2,410 | 0.20 | 0.029 | 16,710,000 |
| SCR + LNB + SOFA | 0.07 | 3,751 | 9,569,000 | 2,551 | 11,363 | 0.23 | 0.032 | 41,610,000 |
| **Cholla 4** | | | | | | | | |
| COFA (baseline) | 0.42 | | | | | | | |
| LNB + SOFA | 0.22 | 3,390 | 820,000 | 242 | | 0.21 | | 3,960,000 |
| SNCR + LNB + SOFA | 0.17 | 4,259 | 2,852,000 | 670 | 2,338 | 0.27 | 0.058 | 10,760,000 |
| ROFA | 0.16 | 4,433 | 3,179,000 | 717 | 1,879 | 0.28 | 0.016 | 11,310,000 |
| ROFA w/Rotamix | 0.12 | 5,129 | 4,537,000 | 885 | 1,951 | 0.34 | 0.055 | 13,500,000 |
| SCR + LNB + SOFA | 0.07 | 5,998 | 13,230,000 | 2,206 | 10,003 | 0.41 | 0.072 | 32,430,000 |

[a] At the Class I area exhibiting the greatest baseline visibility impact, Petrified Forest National Park.

This information is contained in the Cholla BART analyses for each unit, and was relied upon by ADEQ in developing its RH SIP.[56] Estimates of control technology emission rates were developed based on a combination of vendor quotes, contractor information, and internal APS information regarding environmental upgrades.[57] Annual emission reductions were calculated based upon the emission rate estimates combined with annual capacity factors as reported in CAMD data from 2001 to 2006.[58] Control costs were also developed based on a combination of vendor quotes and contractor information. These cost calculations provided line item summaries of capital costs and annual operating costs, but did not provide further supporting information such as detailed equipment lists, vendor quotes, or the design basis for line item costs.

As part of its BART analysis, APS performed visibility modeling in order to evaluate the visibility improvement attributable to each of the $NO_X$ control technologies that it considered. This visibility modeling was performed using three years of meteorological data (2001 to 2003), and was generally performed in accordance with the WRAP protocol, with a few exceptions. For example, rather than using a constant monthly ammonia background concentration of 1.0 ppb as specified in the WRAP protocol, APS used a variable monthly background ammonia concentration that varied from 0.2 ppb to 1.0 ppb.

For assessing the degree of visibility improvement, ADEQ considered only the visibility benefits at the area with the highest base case (pre-control) impact, the Petrified Forest National Park. For each control, ADEQ listed visibility improvement in deciviews, and visibility cost-effectiveness, (Arizona SIP submittal, ''Appendix D: Arizona BART—Supplemental Information'', p.77) as in the comparable section for Apache. For Unit 2, improvements range from 0.19 dv for LNB with SOFA to 0.29 dv for SCR. Costs per deciview range from $3.4 million for LNB to $33.5 million for SCR. Benefits for Unit 3 are about 20 percent lower (0.13 to 0.23 deciview), and for Unit 4 are about 20 percent higher (0.21 to 0.41 deciview), with percent differences increasing with more stringent control. For Unit 3, costs per deciview range from $5 million for LNB with SOFA to $41.6 million for SCR (about 30 percent higher than for Unit 2). For Unit 4, costs range from $4 million for LNB with SOFA to $32.4 million for SCR (about 20 percent higher except that SCR has a slightly lower cost per deciview).

ADEQ concluded (*ibid.,* p. 79) that LNBs with new SOFA systems represent BART for all three units, noting that for all scenarios the visibility benefits were less than 0.5 dv. ADEQ also stated that SCR, the most expensive option, provides only about 0.1 dv benefit more than LNB with SOFA, the least expensive option. This statement appears to apply only to Units 2 and 3; the comparable benefit for Unit 4 is 0.2 dv.

In evaluating APS' BART analysis, ADEQ requested supporting information explaining certain assumptions used in the economic analysis, baseline emissions, and control technology options. Based on this additional

[55] See Docket Item B–06 through –08, APS Cholla BART Analyses, page 2–2.

[56] See Docket Item B–06 through –08, APS Cholla BART Analyses. This information is also summarized in Docket Item B–01, Arizona Regional Haze SIP, Appendix D, Tables 11.3 through 11.5.

[57] As described in Table 3–2, Docket Items B–06 through –08, APS Cholla BART Analyses.

[58] As listed in Table 2–1, Docket Items B–06 through –08. Annual capacity factors used for each unit are 91 percent (Cholla 2), 86 percent (Cholla 3), and 93 percent (Cholla 4).

information as well as APS' original BART analysis, ADEQ determined that LNB with SOFA is BART for $NO_X$ at Cholla Units 2, 3, and 4. In making this determination, ADEQ relied almost exclusively on the degree of visibility improvement. ADEQ cited small visibility improvement on a per-unit basis, stating that ''the change in deciviews between the least expensive and most expensive $NO_X$ control technologies [..] is only 0.104 deciviews.'' [59] ADEQ's determination suggests that total capital costs may have been a consideration, although it is not clear to what extent this may have informed ADEQ's decision making, with the RH SIP simply stating, ''[t]he corresponding capital costs are $5.4 million for LNB/SOFA and $82.8 million for SCR with LNB/SOFA.'' [60]

*EPA's Evaluation:* We disagree with several aspects of the analyses performed for Cholla Units 2, 3, and 4. Regarding the control cost calculations, we note that certain line item costs not allowed by the EPA Control Cost Manual were included, such as owner's costs, surcharge, and AFUDC. Inclusion of these line items has the effect of inflating the total cost of compliance and the cost per ton of pollutant reduced. As a result, we are proposing to find that ADEQ did not follow the requirements of section 51.308(e)(1)(ii)(A) by not properly considering the costs of compliance for each control option.

Regarding ADEQ's analysis of visibility impacts, the modeling procedures relied on by ADEQ for assessing the visibility impacts from Cholla were generally in accord with EPA guidance, but the use of the modeling results in evaluating the BART visibility factor was problematic. As was the case for Apache, ADEQ appears to have considered benefits from controls on only one emitting unit at a time. EPA believes that ADEQ's use of this procedure substantially underestimates the degree of visibility improvement from controls. ADEQ also overlooked comparable benefits at seven Class I areas besides Petrified Forest, thereby understating the full visibility benefits of the candidate controls. Using the default 1 ppb ammonia background concentration would also have increased estimated impacts and control benefits. For these reasons, EPA proposes to find that the ADEQ selection of LNB for Cholla under the degree of visibility improvement BART factor is not adequately supported, and that more stringent control may be warranted.

b. BART for $PM_{10}$

*ADEQ's Analysis:* As of May 2009, Cholla Units 3 and 4 were both equipped with fabric filters for $PM_{10}$ control, while Cholla Unit 2 was equipped with a mechanical dust collector and a venturi scrubber.[61] In its BART analysis, ADEQ noted that the facility had committed to install a fabric filter at Unit 2 by 2015. Because fabric filters are the most stringent control available for reducing $PM_{10}$ emissions, ADEQ did not conduct a full BART analysis, but concluded that fabric filters and an emission limit of 0.015 lb/MMBtu are BART for control of $PM_{10}$ at Units 2, 3, and 4. ADEQ also noted that ''$PM_{10}$ emissions will be measured by conducting EPA Method 201/202 tests.''

*EPA's Evaluation:* Given that ADEQ has chosen the most stringent control technology available and set an emissions limit consistent with other units employing this technology, we are proposing to approve this BART determination of an emission limit of 0.015 lb/MMBtu for $PM_{10}$ at Cholla Units 2, 3, and 4.

c. BART for $SO_2$

Cholla Units 2, 3, and 4 are all equipped with wet lime scrubbers for $SO_2$ control.[62] Specifically, Unit 2 is equipped with four venturi flooded disc scrubbers/absorber with lime reagent, capable of achieving 0.14 lb/MMBtu to 0.25 lb/MMBtu of $SO_2$. Units 3 and 4 were retrofitted in 2009 and 2008, respectively, with scrubbers capable of achieving 0.15 lb/MMBtu of $SO_2$.

*ADEQ's Analysis:* Based on a limited five-factor analysis, ADEQ determined BART for $SO_2$ at Cholla Unit 2 is upgrades to the existing scrubber that would achieve a limit of 0.15 lb/MMBtu. Because the BART analysis submitted by APS was conducted prior to installation of the scrubbers on Units 3 and 4, it included an analysis of other potential control technologies, namely, dry flue gas desulfurization and dry sodium sorbent injection. However, APS had already installed the wet lime scrubbers by the time ADEQ conducted its own BART analysis. Therefore, ADEQ did not consider $SO_2$ controls other than wet lime scrubbers for Units 3 and 4, but determined BART as use of these scrubbers with an associated emission limit of 0.15 lb/MMBtu of $SO_2$.

*EPA's Evaluation:* We are proposing to approve ADEQ's BART determination for $SO_2$ at Cholla Units 2, 3, and 4. Although ADEQ did not fully consider all cost-effective scrubber upgrades as recommended by the BART Guidelines, we have no basis for concluding that additional analysis would have resulted in a lower emission limit. Therefore, we are proposing to approve the $SO_2$ emission limit of 0.15 lb/MMBtu (30-day rolling average) for Cholla Units 2, 3, and 4. However, we are seeking comment on whether additional cost-effective scrubber upgrades are available that would warrant a lower emission limit. If we receive comments establishing that a lower limit is achievable, then we may disapprove the $SO_2$ emissions limit set by ADEQ and promulgate a revised limit for one or more of these units.

4. Coronado Units 1 and 2

Coronado Generating Station consists of two EGUs with a total plant-wide generating capacity of over 800 MW. Units 1 and 2 are both dry-bottom, turbo-fired boilers, each with a gross unit output of 411 MW. Both units are BART-eligible and are coal-fired boilers operating on primarily Powder River Basin sub-bituminous coal.

SRP entered into a consent decree with EPA in 2008.[63] This consent decree resolved alleged violations of the CAA which occurred at Units 1 and 2 of the Coronado Generating Station, arising from the construction of modifications without obtaining appropriate permits under the Prevention of Significant Deterioration provisions of the CAA, and without installing and applying best available control technology. The consent decree resolved the claims alleged by EPA in exchange for SRP's payment of a civil penalty and SRP's commitment to perform injunctive relief including: (1) Installation of pollution control technology to control emissions of $NO_X$, $SO_2$, and PM—including flue gas desulfurization devices to control $SO_2$ on Units 1 and 2 at the Coronado Station and installation of SCR to control $NO_X$ on one of the units (Unit 2); (2) meet specified emission rates or removal efficiencies for $NO_X$, $SO_2$, and PM; (3) comply with a plant-wide emissions cap for $NO_X$; and (4) perform $ 4 million worth of mitigation projects. The consent decree is not a permit, and compliance with the consent decree does not guarantee compliance with all applicable federal, state, or local laws or regulations. The emission rates and

[59] Docket Item B–01, Arizona Regional Haze SIP, Appendix D, Page 79.

[60] *Id.*

[61] See Arizona Regional Haze SIP, Appendix D, pages 79–81 for ADEQ's BART Analysis for $PM_{10}$ at Cholla Units 2, 3, and 4.

[62] See Arizona Regional Haze SIP, Appendix D, pp. 81–83, for ADEQ's BART Analysis for $SO_2$ at Cholla Units 2, 3, and 4.

[63] See Docket Item G–01, Consent Decree between United States and Salt River Project Agricultural Improvement and Power District.

removal efficiencies set forth in the consent decree do not relieve SRP from any obligation to comply with other state and federal requirements under the CAA, including SRP's obligation to satisfy any State modeling requirements set forth in the Arizona SIP.

a. BART for $NO_X$

*ADEQ's Analysis:* ADEQ's BART analysis relied in large part on an analysis submitted by SRP in February 2008. In its analysis, SRP developed baseline $NO_X$ emissions by examining continuous emission monitoring system (CEMS) data from 2001 to 2003.[64] SRP examined several $NO_X$ control technologies, including combustion controls and add-on post combustion controls. A summary of the costs of compliance and visibility impacts associated with these options is presented in Table 13. This information was contained in the SRP Coronado BART analysis, and was relied on by ADEQ in developing its RH SIP. Estimates of control technology emission rates were developed based on information provided by equipment vendors.[65] SRP's analysis did not provide an estimate of annual emissions.

TABLE 13—CORONADO UNITS 1 AND 2: ARIZONA'S COST AND VISIBILITY SUMMARY FOR $NO_X$

| Control option | Emission rate (lb/MMBtu) | | Total emissions removed [a] (tons/yr) | Total annualized cost ($/year) | Cost-effectiveness [b] ($/ton) | | Visibility improvement [c] (deciviews) | | Cost per total deciview improvement [d] ($/dv) | Improvement in visibility index [e] (deciviews) | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | Unit 1 | Unit 2 | | | Average | Incremental (from previous) | Total (from baseline) | Incremental (from previous) | | Total (from base case) | Incremental (from previous) |
| OFA (baseline) | 0.433 | 0.466 | | | | | | | | | |
| Full LNB + OFA | 0.32 | 0.32 | 5,838 | $1,227,000 | $210 | | 0.12 | | $10,225,000 | 0.11 | |
| Full SNCR + LNB + OFA | 0.22 | 0.22 | 10,195 | 4,654,000 | 456 | 787 | 0.16 | 0.04 | 29,087,500 | 0.19 | 0.080 |
| Partial SCR + LNB + OFA [f] | 0.32 | 0.08 | 11,003 | 8,557,000 | 778 | 4,830 | 0.24 | 0.12 | 35,654,167 | 0.22 | 0.030 |
| Full SCR + LNB + SOFA | 0.08 | 0.08 | 16,730 | 17,090,000 | 1,022 | 1,490 | 0.39 | 0.27 | 43,820,513 | 0.34 | 0.120 |

[a] SRP did not provide estimates of annual emissions in its BART analysis. These values are summarized from the Arizona RH SIP.
[b] Cost-effectiveness was not presented in the Arizona RH SIP. These values are calculated from the emission removal and annualized costs that were included in the RH SIP.
[c] Visibility improvement at the Class I area exhibiting the greatest baseline visibility impact, Petrified Forest National Park, from the SRP Coronado BART Analysis.
[d] Cost per total deciview improvement was not presented in the Arizona RH SIP. These values are calculated from the annualized costs that were included in the RH SIP, and the visibility improvement at Petrified Forest National Park, from the SRP Coronado BART Analysis.
[e] Visibility index used in the Arizona RH SIP is the average of the impacts over the nine closest Class I areas.
[f] This control option examined LNB+OFA on Unit 1 and SCR on Unit 2.

Control costs for the various options considered were developed by Sargent and Lundy, the engineering firm retained by SRP for emission control projects at Coronado. In its BART analysis and subsequent additional response to ADEQ, SRP provided summaries of total control costs, such as total annual operating and maintenance costs and total annualized capital cost, but did not provide cost information at a level of detail that included line item costs. [66]

As part of its BART analysis, SRP performed visibility modeling in order to evaluate the visibility improvement attributable to each of the $NO_X$ control technologies that it considered. This visibility modeling was performed using three years of meteorological data (2001 to 2003), and relied partially on the WRAP protocol with certain revisions based on EPA and Federal Land Manager guidance that became available in the intervening period. For example, the WRAP protocol used CALPUFF model version 6, whereas SRP used the current EPA-approved CALPUFF version 5.8.

For assessing the degree of visibility improvement, ADEQ considered a visibility index, defined as the average of the visibility benefits at the closest nine Class I areas. The average included the five areas with the highest baseline impacts. This metric is unlike that used for Apache and Cholla, for which the benefits at the single area with maximum baseline impact were used. Since it is an average, it is somewhat similar to the sum of benefits over the nine areas, a cumulative metric used in other analyses, except it is divided by nine to compute the average. (Typically the sum would be computed over all 17 Class I areas impacted by the Coronado facility.) For each control, ADEQ listed the average visibility improvement in deciviews, and cost in millions of dollars per average deciview improvement.[67] Improvements in the visibility index ranged from 0.11 dv for LNB with OFA to 0.34 dv for SCR. Costs per deciview for the index ranged from $11.1 million for LNB to $50.3 million for SCR (not shown in the Table above).

While an average of the visibility benefits over the nearest areas is an informative number, it is not directly comparable to the more typical metrics of the maximum benefit seen at any area, and sum over the areas. Moreover, neither the ADEQ RH SIP nor the facility's report (BART Analysis for the Coronado Generating Station Units 1 & 2, Document No. 05830–012–200, ENSR Corporation, February 2008) include control benefits for individual Class I areas. Thus, the maximum area benefit cannot be read from either document. However, the benefits can be computed from the individual area impacts that are provided in SRP's report, including for Petrified Forest National Park, which had the highest baseline impact. Figures that are comparable to those for Apache and Cholla are included in the Table 13. Coronado's maximum area visibility benefits range from 0.12 dv for LNB to 0.39 dv for SCR. The costs per deciview range from $10.2 million for LNB with OFA to $43.8 for SCR.

In evaluating SRP's BART analysis, ADEQ requested additional supporting information from SRP regarding control cost calculations, and for further explanation regarding SRP's recommendation for BART for $NO_X$. In developing its Regional Haze SIP, ADEQ

[64] See Docket Item B–10, SRP Coronado BART Analysis, page 3–1.

[65] See Docket Item B–10, SRP Coronado BART Analysis, p. 4–5.

[66] See Docket Item B–11, Additional SRP Coronado response.

[67] Arizona RH SIP, Appendix D, p. 112.

determined that LNB with OFA constitutes BART for $NO_X$ at Coronado Units 1 and 2. In making this determination, ADEQ did not provide adequate information regarding its rationale or weighing of the five factors, stating only ''[a]fter reviewing the BART analysis provided by the company, and based upon the information above, ADEQ has determined that BART for $NO_X$ at Coronado Units 1 and 2 is advanced combustion controls (Low $NO_X$ burners with OFA) with an associated $NO_X$ emission rate of 0.32 lb/MMBtu [..]'' [68]

*EPA's Evaluation:* We disagree with several aspects of the BART analysis for Coronado Units 1 and 2. Regarding the control cost calculations, we note that SRP did not provide ADEQ with control cost calculations at a level of detail that allowed for a comprehensive review. Without such a level of review, we do not believe that ADEQ was able to evaluate whether SRP's control costs were reasonable. As a result, we are proposing to find that ADEQ did not follow the requirements of section 51.308(e)(1)(ii)(A) because ADEQ did not properly consider the costs of compliance for each control option.

The modeling procedures relied on by ADEQ for assessing the visibility impacts from Coronado were generally in accord with EPA guidance. Coronado Units 1 and 2 were modeled together, and the modeling was done with the current regulatory version 5.8 of the CALPUFF modeling system.[69] However, the use of the modeling results in evaluating the BART visibility factor was problematic. The modeling results show that, of the controls considered, only SCR would provide substantial visibility benefits; the other controls options would provide roughly half the 0.5 dv contribution benchmark. ADEQ did not consider the typical visibility metrics of benefit at the area with maximum impact, nor benefits summed over the areas. Using the default 1 ppb ammonia background concentration would also have increased estimated impacts and control benefits. For these reasons, EPA proposes to find that the ADEQ selection of LNB with OFA for Coronado under the degree of visibility improvement BART factor is not adequately supported, and that more stringent control may be warranted. ADEQ provided little reasoning about the visibility basis for the Coronado BART selection. For example, there is no weighing of the visibility benefits and visibility cost-effectiveness for the various candidate controls and the various Class I areas.

In addition to the problems noted above, we find that overall ADEQ has not documented its evaluation of the results of its five-factor analysis, as required by 51.308(e)(1)(ii)(A) and the BART Guidelines. Although ADEQ has developed information regarding each of the five factors, its selection of BART does not cite or interpret information from its analyses. ADEQ does not, for example, indicate whether or not it considered any cost thresholds to be reasonable or expensive in analyzing the costs of compliance for the various control options. We note that ADEQ has made similar $NO_X$ BART determinations of LNB with OFA at other facilities, such as Cholla Power Plant. Although ADEQ's BART determinations for these other facilities implied that cost of compliance was an important consideration, it does not provide a rationale for the determination of $NO_X$ BART at Coronado.[70] Therefore, we propose to determine that ADEQ did not follow the requirements of section 51.308(e)(1)(ii)(A). We propose to disapprove ADEQ's selection of LNB with OFA as BART for $NO_X$ at Coronado Units 1 and 2.

b. BART for $PM_{10}$

Emissions of $PM_{10}$ from Coronado Units 1 and 2 are currently controlled by hot-side ESPs.[71] Under the terms of the Consent Decree described above in Section 4, SRP is required to optimize its ESPs to achieve a $PM_{10}$ emission rate of 0.030 lb/MMBtu.[72]

*ADEQ's Analysis:* ADEQ conducted a streamlined $PM_{10}$ BART analysis for Coronado Units 1 and 2. In particular, ADEQ found that ''BART for similar emissions units with similar emissions controls was determined to be 0.03 lb/MMBtu.'' ADEQ concluded that because Coronado Units 1 and 2 are already meeting a limit of 0.03 lb/MMBtu, ''further analysis was determined to be unnecessary.''

*EPA's Evaluation:* ADEQ's analysis does not demonstrate that all potential upgrades to the existing ESPs were fully evaluated. However, we have no evidence that additional reductions in $PM_{10}$ emissions would be achievable or cost-effective, or that such reductions would yield substantial visibility benefits. Therefore, we propose to approve ADEQ's $PM_{10}$ BART determination at Coronado. However, we are seeking comment on whether additional cost-effective upgrades to the existing ESPs are available that would warrant a lower emission limit. If we receive comments establishing that a lower limit is achievable, then we may disapprove the $PM_{10}$ emissions limit set by ADEQ and promulgate a revised limit for one or both of these units.

Finally, we are seeking comment on whether test methods other than EPA Method 201 and 202 [73] (chosen by ADEQ) should be allowed or required for establishing compliance with the $PM_{10}$ limits that we are approving. In particular, as explained below, use of SCR at these units is expected to result in increased condensable particulate matter in the form of $H_2SO_4$. In effect, the emission limit would be more stringent than intended by ADEQ and would likely not be achievable in practice. In order to avoid this result, while still assuring proper operation of the particulate control devices, we are requesting on comment on whether to allow compliance with the $PM_{10}$ limit to be demonstrated using test methods that do not capture condensable particulate matter, namely EPA Methods 1 through 4 and Method 5 or Method 5e.[74] Method 201 is very rarely used for testing. The typical method used for filterable $PM_{10}$ is Method 201A, ''constant sampling rate procedure,'' which is similar to Method 201, but is much more practical to perform on a stack.

c. BART for $SO_2$

Emissions of $SO_2$ at Coronado Units 1 and 2 are currently controlled with the use of low-sulfur coal and partial wet flue gas.[75] However, the consent decree between EPA and SRP described above requires installation of wet flue gas desulfurization (WFGD) systems at either Unit 1 or Unit 2 by January 2012, and at the remaining unit by January 1, 2013. Both units must achieve and maintain a 30-day rolling average $SO_2$ removal efficiency of at least 95.0

[68] Docket Item B–01, Arizona Regional Haze SIP, Appendix D, Page 112.

[69] Arizona Regional Haze SIP, Appendix D, p. 112.

[70] We do note, however, that SRP does provide some additional analysis on this position in the BART analysis it submitted to ADEQ and in the responses it provided to ADEQ's additional questions. Aside from stating that it reviewed SRP's analysis, ADEQ did not specifically reference or include any aspects of SRP's analysis in the RH SIP. As a result, we are not assuming that ADEQ necessarily agrees with SRP's rationale, and have therefore not provided an analysis of it.

[71] See Arizona Regional Haze SIP, Appendix D, p. 112 for ADEQ's BART Analysis for $PM_{10}$ at Coronado Units 1 and 2; and BART Analysis for Coronado Generating Station Units 1 and 2 (February 2008) for SRP's analysis.

[72] Docket Item G–01, Consent Decree between United States and Salt River Project Agricultural Improvement and Power District, § V.

[73] See 40 CFR part 51 appendix M.

[74] See 40 CFR part 60 appendix A.

[75] See Arizona Regional Haze SIP, Appendix D, pp. 113–15 for ADEQ's BART Analysis for $PM_{10}$ at Coronado Units 1 and 2; and Docket No. B.10, BART Analysis for Coronado Generating Station Units 1 and 2 (Feb. 2008) for SRP's analysis.

percent or a 30-day rolling average $SO_2$ emissions rate of no greater than 0.080 lb/MMBtu.

*ADEQ's Analysis:* Because WFGD is the most effective control technology available for controlling $SO_2$ emissions, ADEQ did not evaluate other control options. Table 14 summarizes Arizona's the costs of compliance and improvement in visibility expected to result from installation of WFGD at both units. Based on this information, ADEQ determined $SO_2$ BART for both units is the installation of WFGDs and an emission rate of 0.08 lbs/MMBtu on 30-day rolling average basis.

TABLE 14—CORONADO UNITS 1 AND 2: ARIZONA'S BART SUMMARY FOR $SO_2$

| | Option 1, baseline | Option 2, WFGD |
|---|---|---|
| Reduction in Emission (tpy) | ................................ | 25,753 |
| Annualized Cost | ................................ | $44,353,330 |
| Visibility Index (dv) | 2.66 | 1.28 |
| Improvement in Visibility Index (dv) | ................................ | 1.38 |
| Incremental Cost-effectiveness ($ per dv) | ................................ | $32,140,094 |

*EPA's Evaluation:* We are proposing to approve ADEQ's $SO_2$ BART determination for Coronado Units 1 and 2. Although we do not necessarily agree with the underlying cost and visibility analyses performed by SRP, we have no evidence that additional analysis would have resulted in a lower emission limit. Therefore, we propose to approve ADEQ's $SO_2$ emission limit of 0.08 lb/MMBtu (30-day rolling average) for Coronado Units 1 and 2. However, we are seeking comment on whether a lower emission limit may be achievable when the units are burning a lower-sulfur coal. If we receive comments establishing that a lower limit is achievable, then we may disapprove the $SO_2$ emissions limit set by ADEQ and promulgate a revised limit for one or both of these units.

*D. Enforceability of BART Limits*

Regional Haze SIPs must include requirements to ensure that BART emission limits are enforceable. In particular, the RHR requires inclusion of (1) A schedule for compliance with BART for each source subject to BART; (2) a requirement for each BART source to maintain the relevant control equipment; and (3) procedures to ensure control equipment is properly operated and maintained.[76] General SIP requirements also mandate that the SIP include all regulatory requirements related to monitoring, recordkeeping and reporting for the BART emissions limitations.[77] ADEQ did not include any of these elements in its Regional Haze SIP.[78] Therefore, we are proposing to disapprove this aspect of the Regional Haze SIP for these three sources and to promulgate a FIP to ensure the emission limits are enforceable.

**VII. EPA's Proposed FIP Actions**

*A. EPA's BART Analyses and Determinations*

EPA conducted a new five-factor BART analysis of the three facilities in order to evaluate Arizona's RH SIP, and to document the technical basis for proposing BART determinations in our FIP. Because EPA generally concurs with ADEQ's BART analyses in Steps 1 and 2 (Identify All Available Retrofit Control Technologies and Eliminate Technically Infeasible Options), we focused our technical analysis on Steps 3, 4 and 5 (Evaluate Control Effectiveness of Remaining Control Technologies, Evaluate Impacts and Document Results, and Evaluate Visibility Impacts). We relied on contractor assistance from the University of North Carolina Institute for the Environment to evaluate control effectiveness, perform cost calculations, and conduct new visibility modeling for each of the units at the three facilities, except Apache Generating Station Unit 1 for which this level of analysis was unnecessary. Our approach to each of these factors is explained below, followed by our BART determinations for the three sources in the next section. Copies of the contractor's reports and the details of our BART analyses are in our Technical Support Document (TSD) available in the docket.

1. Costs of Compliance

*Cost Estimates and Calculations:* In estimating the costs of compliance, we have relied on facility data from a number of sources including ADEQ, the Energy Information Administration (EIA), and EPA's Control Cost Manual. As discussed previously, ADEQ, in developing its RH SIP, requested certain clarifying information from the facilities regarding their control cost calculations, including greater detail regarding the underlying assumptions. ADEQ received responses of varying detail to these requests. Although in some cases the facilities provided summaries of certain broad line item costs, in no case does the supporting information that is available provide detail at a level that allows for critical review. In the case of SRP Coronado Generating Station, ADEQ received only a broad summary of control costs without itemized breakdowns of specific costs.

As a result, we have used EPA's Integrated Planning Model (IPM) to calculate the capital costs and annual operating costs associated with the various $NO_X$ control options. EPA's Clean Air Markets Division (CAMD) uses IPM to evaluate the cost and emissions impacts of proposed policies to limit emissions of $SO_2$, $NO_X$, carbon dioxide ($CO_2$), and mercury (Hg) from the electric power sector. Developed by ICF Consulting, Inc. and used to support public and private sector clients, IPM is a multi-regional, dynamic, deterministic linear programming model of the U.S. electric power sector. EPA has used IPM in rulemakings such as the Mercury and Air Toxics Standard and the Cross-State Air Pollution Rule. For the purposes of this BART determination, we specifically used only the $NO_X$ emission control technology cost methodologies contained in EPA's IPM Base Case v4.10 (August 2010).[79] For Base Case v4.10, EPA's Clean Air Markets Division contracted with engineering firm Sargent and Lundy to perform a complete bottom-up engineering reassessment of the cost and performance assumptions for $SO_2$ and nitrogen oxides $NO_X$ emission controls. Summaries of our control cost estimates for the various control technology options considered for each unit are included below. Detailed cost

[76] 40 CFR 51.308(e)(1).

[77] See, e.g. CAA section 110(a)(2) (F) and 40 CFR 51.212(c).

[78] As described above, ADEQ did specify a test method for $PM_{10}$ for each of the relevant sources (Method 201/202). However, we are proposing to also allow the use of test methods that do not capture condensable particulate matter, namely EPA Methods 1 through 4 and Method 5 or Method 5e.

[79] *http://www.epa.gov/airmarkt/progsregs/epa-ipm/BaseCasev410.html#documentation.*

calculations, including our contractor's report and cost calculation spreadsheets, are in the Technical Support Document.

We used publicly available information to estimate that AEPCO is a small utility. EPA requested information from AEPCO on the economics of operating Apache Generating Station and what impact the installation of SCR may have on the economics of operating Apache Generating Station. Specifically, EPA is seeking information on the ability of AEPCO to recover the cost of pollution control technology through rate increases and the impact those rate increases may have on AEPCO's customers. If we receive comments sufficiently documenting that installation of SCR may have a severe impact on the economics of operating Apache Generating Station, we may incorporate such considerations in our selection of BART. Our impact analysis and request for comment is discussed in more detail below, under EPA's BART Determinations for Apache Units 2 and 3.

*Control Effectiveness:* The evaluation of control effectiveness is an important part of a five-factor analysis because it influences both cost-effectiveness and visibility benefits. The BART Guidelines note that for each technically feasible control option:

> ''It is important * * * that in analyzing the technology you take into account the most stringent emission control level that the technology is capable of achieving. You should consider recent regulatory decisions and performance data (e.g., manufacturer's data, engineering estimates and the experience of other sources) when identifying an emissions performance level or levels to evaluate.'' [80]

In general, our estimates of LNB and SNCR control effectiveness differ slightly from the control effectiveness levels considered by ADEQ. In the case of LNB, for example, this is the result of the fact that actual emissions data for LNB performance were available for certain units at the time of our analysis. ADEQ's analysis was performed at an earlier date when these emissions data were not available. More detailed information regarding these differences is in our discussion of individual facilities in the following sections of this notice, as well as in our TSD.

In particular, we find that ADEQ did not adequately support its estimate of SCR control effectiveness. SCR, as an add-on control technology, can be installed by itself as a standalone option or in conjunction with burner upgrades. In cases where units can be upgraded with combustion control technology such as low-NOx burners, SCR is commonly installed as an add-on post-combustion control. When evaluating control options with a range of emission performance levels, the BART Guidelines indicate that ''in analyzing the technology you take into account the most stringent emission control level that the technology is capable of achieving.'' [81] Existing vendor literature and technical studies indicate that SCR systems are capable of achieving a 0.05 lb/MMBtu emission rate (approximately 80–90% control efficiency) and that this emission rate can be achieved on a retrofit basis, particularly when combined with combustion control technology such as LNB.[82]

For control options involving the installation SCR in conjunction with LNB, ADEQ considered the achievable emission rate to be between 0.07 lb/MMbtu (for Apache and Cholla) and 0.08 lb/MMbtu (for Coronado). These emission rates are within a range of SCR performance that has been considered by other western states in preparing RH SIPs, and may possibly be an appropriate estimation of the site-specific level of SCR performance for coal-fired units at Apache, Cholla, and Coronado. We note that the BART Guidelines indicate that, ''In assessing the capability of the control alternative, latitude exists to consider special circumstances pertinent to the specific source under review [* * *]. However, you should explain the basis for choosing the alternate level (or range) of control in the BART analysis.'' [83] Although the alternate levels of emission control considered by ADEQ for SCR in conjunction with LNB were stated in each respective facility's BART analysis, these emission rates were not further supported by any calculations, engineering analysis, or documentation. We do not believe that AEPCO, APS, and SRP have provided adequate supporting analysis to justify these emission rates. We are seeking comment on whether it is appropriate to consider an emission rate less stringent than 0.05 lb/MMBtu when evaluating the installation SCR in conjunction with LNB at Apache, Cholla, and Coronado.

In the absence of source-specific considerations warranting a less stringent control level, we presume that an emissions limit of 0.05 lb/MMBtu is achievable by these units through the use of SCR in addition to advanced combustion controls. We have recently received information from AEPCO and SRP regarding potential $NO_X$ controls at their facilities. This information arrived too late to be fully evaluated for this proposed rulemaking, and EPA will need additional documentation from the utilities to support the information that they have provided to date. We have put the utility information in the docket for public review, and we will evaluate the information, and any additional information that the utilities may want to provide prior to making our final BART determinations.[84] If we receive additional comments that sufficiently document source-specific considerations justifying the use of an emission rate less stringent than 0.05 lb/MMBtu, we may incorporate such considerations in our selection of BART.

2. Energy and Non-Air Environmental Impacts

*Energy Impacts:* With respect to the potential energy impacts of the BART control options, we note that SCR incurs a draft loss that will increase parasitic loads, and that other emissions controls may also have modest energy impacts. The costs for direct energy impacts, i.e., power consumption from the control equipment and additional draft system fans from each control technology, are included in the cost analyses and are not considered further in this section. Indirect energy impacts, such as the energy to produce raw materials, are not considered, consistent with the BART guidelines.

*Ammonia Adsorption:* Ammonia adsorption (resulting from ammonia injection from SCR or selective non-catalytic reduction—SNCR) to fly ash is generally not desirable due to odor but does not impact the integrity of the use of fly ash in concrete. However, other $NO_X$ control technologies, including LNB, also have undesirable impacts on fly ash. LNBs increase the amount of unburned carbon in the fly ash, also known as Loss of Ignition (LOI), which does affect the integrity of the concrete. Commercial scale technologies exist to remove ammonia and LOI from fly ash. Moreover, the impact of SCR on fly ash is smaller than the impact of LNB on fly ash, and in both cases, the adverse effects can be mitigated.[85] We conclude

[80] 40 CFR part 51, appendix Y § IV.D.3.

[81] 70 FR 39166.

[82] See Docket Items G–04, ''Emissions Control: Cost-Effective Layered Technology for Ultra-Low $NO_X$ Control'' (2007), Docket Item G–05 ''What's New in SCRs'' (2006), and Docket Item G–06 ''Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers'' (2005).

[83] 40 CFR part 51, appendix Y § IV.D.3.

[84] Docket Items C–15 ''Letter from Kelly Barr (SRP) to Deborah Jordan (EPA)'' and C–16 ''Letter from Michelle Freeark (AEPCO) to Deborah Jordan (EPA).''

[85] ''Impact of Ammonia in Fly Ash on its Beneficial Use,'' Memorandum from Nancy Jones and Stephen Edgerton, EC/R Incorporated, to Anita

Continued

that the ability of the relevant facilities to sell fly ash is unlikely to be affected by the installation of SCR and SNCR technologies.

*Safety:* SCR and SNCR may involve potential safety hazards associated with the transportation and handling of anhydrous ammonia. Since each of the relevant facilities is served by a nearby railroad line, EPA concludes that the use of ammonia does not pose any additional safety concern as long as established safety procedures are followed.

Thus, EPA proposes to find that potential energy and non-air quality impacts do not warrant elimination of any of the otherwise feasible control options for $NO_X$ at any of the sources.

3. Pollution Control Equipment in Use at the Source

The presence of existing pollution control technology at each source is reflected in our BART analysis in two ways: First, in the consideration of available control technologies, and second, in the development of baseline emission rates for use in cost calculations and visibility modeling. As noted above, we largely agree with ADEQ's consideration of available control technologies. However, because several of the affected units have had new controls installed in the last several years, we have adjusted the baseline emissions periods to reflect current control technology at the sources, as described further below in our proposed BART determinations.

4. Remaining Useful Life of the Source

We are considering each source's ''remaining useful life'' as one element of the overall cost analysis as allowed by the BART Guidelines. Since we are not aware of any federally- or State-enforceable shut-down date for any of the affected sources, we have used the default 20-year amortization period in the EPA Cost Control Manual as the remaining useful life of the facilities considered in this proposed action.

5. Degree of Improvement in Visibility

EPA estimated the degree of visibility improvement expected from a BART control based on the difference between baseline visibility impacts prior to controls and visibility impacts with controls in operation. EPA used the CALPUFF model version 5.8 [86] to determine the baseline and post-control visibility impacts for all three facilities. EPA followed the modeling approach recommended in the BART Guidelines. We developed a modeling protocol, used maximum daily emissions as a baseline, applied estimated percent reductions for alternative control technologies, and used the CALPUFF model to estimate visibility impacts at Class I areas within 300 kilometers.

a. Modeling Protocol

A modeling protocol was developed by our contractor [87] at the University of North Carolina that is based largely on the WRAP protocol,[88] although there are a few differences between our protocol and that of the WRAP. Both protocols used meteorological inputs for 2001, 2002, and 2003 based on the Mesoscale Model version 5 (MM5). EPA meteorological inputs differed from the WRAP's in that the WRAP incorporated upper air data, as recommended by the Federal Land Managers, and also values for some parameters that enabled smoother and more realistic wind fields. These CALMET inputs were developed by the ENSR corporation for modeling of emissions at the Navajo Generating Station.[89] Another key difference was EPA's use of the current regulatory version of the CALPUFF modeling system, version 5.8. Facility stack parameters, such as stack height and exit temperature, were generally the same as those provided by WRAP member states to the WRAP, except that in some cases updated parameters were provided by the facilities at EPA's request.

We performed separate CALPUFF modeling runs using baseline emissions, and using the emissions remaining after each candidate control technology was applied to the baseline. For baseline PM emissions, EPA used the WRAP's estimates. However, following procedures developed by the National Park Service,[90] EPA divided those emissions into separate chemical species, and into separate coarse and fine particle fractions, to reflect better their varying visibility impacts.

Although costs and emission reductions for each candidate BART control technology must necessarily be calculated separately for each emitting unit of a facility, emissions from all the units will be emitted into the air simultaneously. EPA modeled all units (stacks) and pollutants simultaneously. That is, even though only $NO_X$ BART alternatives were evaluated, $SO_2$ and $PM_{10}$ emissions were also included in the modeling. Modeling all emissions from all the units accounts for the chemical interaction between multiple plumes, and between the plumes and the background concentrations. This also accounts for the facts that deciview benefits from individual units are not additive, and that each EPA BART proposal is for the facility as a whole.

b. Baseline Emissions

Baseline $NO_X$ and $SO_2$ emissions for the facilities were generally based on the maximum daily emissions from recent data in EPA's CAMD database, with data examined for 2008 to 2011. The CAMD data derive from Continuous Emissions Monitoring in place at the facilities, and give the actual emissions that occurred. However, in cases where EPA is proposing to approve the BART emissions limits submitted by ADEQ, EPA used emission rates based on those limits, in lb/MMBtu, in combination with the maximum daily heat rate in MMBtu/hour from the CAMD data. The baseline emissions used by EPA reflect current fuels and control technologies in place at the facilities, as well as regulatory requirements the facilities will be required to meet independent of EPA's BART determination. This results in a more realistic estimate of current visibility impacts, and of the improvements that one would expect to result from implementation of EPA's proposed BART controls.

Lee, U.S. EPA/Region 9, August 31, 2010. Also see the TSD for further discussion.

[86] EPA relied on version 5.8 of CALPUFF because it is the EPA-approved version promulgated in the Guideline on Air Quality Models (40 CFR part 51, Appendix W, section 6.2.1.e; 68 FR 18440, April 15, 2003. It was also the approved version when EPA promulgated the BART Guidelines (70 FR 39122, July 6, 2005). EPA updated the specific version to be used for regulatory purposes on June 29, 2007, including minor revisions as of that date; the approved CALPUFF modeling system includes CALPUFF version 5.8, level 070623, and CALMET version 5.8 level 070623. At this time, any other version of the CALPUFF modeling system would be considered an ''alternative model'', subject to the provisions of Guideline on Air Quality Models section 3.2.2(b), requiring a full theoretical and performance evaluation.

[87] *Technical Analysis for Arizona Regional Haze FIPs: Modeling Protocol for Subject-to-BART and BART Control Options Analyses,* EP–D–07–102 WA5–12 Task 5, Institute for the Environment, University of North Carolina at Chapel Hill, March 14, 2012

[88] *CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States,* Western Regional Air Partnership (WRAP); Gail Tonnesen, Zion Wang; Ralph Morris, Abby Hoats and Yiqin Jia, August 15, 2006. Available on UCR Regional Modeling Center web site, BART CALPUFF Modeling, *http://pah.cert.ucr.edu/aqm/308/bart.shtml.*

[89] *Revised BART Analysis for the Navajo Generating Station Units 1–3,* ENSR Corporation, Document No. 05830–012–300, January 2009, Salt River Project—Navajo Generating Station, Tempe, AZ.

[90] ''Particulate Matter Speciation'', National Park Service, 2006. *http://www.nature.nps.gov/air/Permits/ect/index.cfm.*

c. Emission Reductions for Alternative Controls

For the CALPUFF modeling to assess visibility after application of a control technology, the percent control expected from the technology was applied to the baseline maximum daily emissions just described, as recommended in the BART Guidelines. As discussed elsewhere, LNB and SNCR each were assumed to reduce $NO_X$ by 30 percent, and SCR was assumed to reduce $NO_X$ by 90 percent. However, for SCR, we used a lower bound of 0.05 lb/MMBtu $NO_X$, an emission rate that we have confidence is achievable, as discussed above under ''Control Effectiveness''. The percent reduction actually applied to the maximum daily emissions was whatever was required to reduce the CAMD annual average emission factor down to this 0.05 lb/MMBtu $NO_X$. For the various emitting units at the facilities, this ranged from 80 to 89 percent, instead of a full 90 percent reduction. Finally, in modeling the visibility impact of SCR, EPA accounted for the increased sulfuric acid emissions that occur when the SCR catalyst oxidizes $SO_2$ present in the flue gas, using an estimation procedure developed by the Electric Power Research Institute[91]. (*Estimating Total Sulfuric Acid Emissions from Stationary Power Plants,* Version 2010a, 1020636, Technical Update, Electric Power Research Institute, April 2010) This side effect of SCR's $NO_X$ reduction increases sulfate emissions and decreases the visibility benefits of SCR by around 5 percent.

d. Visibility Impacts

*CALPUFF Modeling:* EPA followed the BART Guidelines in assessing visibility impacts. For each Class I area within 300 km of a facility, the CALPUFF model is used to simulate the baseline visibility impact of each facility and the impacts resulting after alternative controls are applied. However, certain aspects of assessing visibility with CALPUFF are not fully addressed in the Guidelines. These aspects include which ''98th percentile'' from the model to use, the visibility calculation method (old vs. revised IMPROVE equation), and natural background concentrations (annual average versus best 20 percent of days).

As recommended in the BART Guidelines, the 98th percentile daily impact in deciviews is used as the basic metric of visibility impact. (For a given Class I area, and for each modeled day, the model finds the maximum impact. From among the 365 maximum daily values, the 98th percentile is chosen, that is, the 8th highest.) Since multiple years of meteorology are modeled, there are at least three ways to use the model results: The maximum from among the 98th percentiles for the individual years 2001, 2002, and 2003 (''maximum''); the average of these three (''average''), or a single 98th percentile computed from all three years of data together (''merged'', the 22nd high among 1095 daily values). The average and merged values are both unbiased estimates of the true 98th percentile; for this proposal EPA has used the merged value. The more conservative maximum value would be appropriate for a screening purpose, such as for determining whether a source is subject to BART.

*Visibility Calculation Method:* The visibility calculation method relied on by EPA differed from that used by ADEQ. Visibility impacts may be simulated with CALPUFF using either the old or the revised IMPROVE equation for translating pollutant concentrations into deciviews; these are respectively CALPUFF visibility methods 6 and 8 (implemented in the CALPOST post-processor). Many BART assessments were performed before method 8 was incorporated into CALPUFF, so method 6 was generally for past assessments. However, in this proposal EPA is primarily relying on method 8. Method 8 is currently preferred by the Federal Land Managers; since the revised IMPROVE equation performs better at estimating visibility.[92] For the facilities examined in this proposal, baseline impacts using method 6 would average about 10 percent higher than those using method 8 (with a range of 3 percent lower to 22 percent higher depending on facility and Class I area; the effect for areas showing the largest benefit from control was similar to the average).

Another CALPUFF choice is whether to calculate visibility impacts relative to annual average natural conditions, or relative to the best 20 percent of natural background days; these may be referred to as ''a'' and ''b''. For both ''a'' and ''b'', background concentrations for each Class I area are available in a Federal Land Managers' document.[93] EPA Guidance allows for the use of either ''a'' or ''b.''[94] [95] Since the annual average has worse visibility and higher deciviews than the best days do, a given facility impact will be smaller relative to the average than it is relative to the best days. That is, a facility's impact will stand out less under poorer visibility conditions. Thus, modeled facility impacts and control benefits appear smaller when ''a'' is used than when ''b'' is used. In this proposal, EPA is relying on ''b'', best 20 percent, consistent with initial EPA recommendations for BART assessments. For the facilities examined in this proposal, baseline impacts would average about 20 percent lower using background ''a'' than those using background ''b'' (with a range of 18 percent to 28 percent lower depending on facility and Class I area; the effect for areas showing the largest benefit from control was similar to the average).

Considering visibility method and choice of background together, the BART visibility assessments relied on by ADEQ used method ''6a'', the old IMPROVE equation, and impacts relative to annual average natural conditions. This is a valid approach, and is consistent with EPA guidance.[96] However, for this proposal, EPA considered all four combinations of IMPROVE equation version and natural background: 6a, 6b, 8a, and 8b. EPA primarily relied on method ''8b'', that is, the revised IMPROVE equation, and impacts relative to the best 20 percent of natural background days. This is most consistent with our current understanding of how best to assess source specific visibility impacts. Combining the differences in visibility method and chosen background, for the facilities examined in this proposal, baseline impacts would average about 15 percent lower using method ''6a'' than those using method ''8b'' (with a range of 3 percent to 37 percent lower depending on facility and Class I area; the effect for areas showing the largest benefit from control was similar to the average). Results for all the various

[91] *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants,* Version 2010a, 1020636, Technical Update, Electric Power Research Institute, April 2010.

[92] Pitchford, Marc, 2006, ''New IMPROVE algorithm for estimating light extinction approved for use'', The IMPROVE Newsletter, Volume 14, Number 4, Air Resource Specialists, Inc.; Web page: *http://vista.cira.colostate.edu/improve/Publications/news_letters.htm*.

[93] *Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report—Revised* (2010), U.S. Forest Service, National Park Service, U.S. Fish and Wildlife Service, October 2010. Available on Web page *http://www.nature.nps.gov/air/Permits/flag/*.

[94] BART Guidelines, 70 FR 39125, July 6, 2005. ''Finally, these final BART guidelines use the natural visibility baseline for the 20 percent best visibility days for comparison to the 'cause or contribute' applicability thresholds.''

[95] ''Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations'', memorandum from Joseph W. Paisie, EPA OAQPS, July 19, 2006, p.2.

[96] Additional Regional Haze Questions'', September 27, 2006 Revision, EPA OAQPS.

visibility methods are available in the TSD.

*B. EPA's FIP BART Determinations*

1. Apache Units 2 and 3

a. Costs of Compliance

Our general approach to calculating the costs of compliance is described in VII.A.1., while issues unique to Apache Units 2 and 3 are described herein. In particular, we highlight below certain aspects of our analysis of this factor that differ from ADEQ's and AEPCO's analysis.

i. Selection of Baseline Period

AEPCO's BART analysis used a 2002 to 2007 time period in order to establish its baseline $NO_X$ emissions. In our analysis, we decided to make use of the most recent Acid Rain Program emission data reported to CAMD, which, at the time that we began our analysis in 2011, was the three-year period from 2008 to 2010. Based on CAMD documentation, no new control technology beyond the existing OFA system has been installed on either Apache Unit 2 or 3. We consider the use of this more recent baseline period to be a realistic depiction of anticipated future emissions.[97]

ii. SCR Control Efficiency

In determining the control efficiency of SCR, we have relied upon an SCR level of performance of 0.05 lb/MMBtu, which is more stringent than the level of performance used by ADEQ in its SIP. In the Apache BART analyses submitted to ADEQ, AEPCO indicated an SCR level of performance of 0.07 lb/MMBtu, but did not provide site-specific information describing how this emission rate was developed or discussing why a more stringent 0.05 lb/MMBtu level of performance could not be attained. Our control cost calculations for the SCR and LNB with OFA control options are based upon the control efficiency of SCR (combined with LNB) summarized in Table 15.

TABLE 15—APACHE 2 AND 3: EPA'S SCR (COMBINED WITH LNB) CONTROL EFFICIENCY

| Unit | Baseline emission rate [1] (lb/MMBtu) | SCR emission rate | SCR control efficiency (percentage) |
|---|---|---|---|
| Apache 2 | 0.371 | 0.05 | 87 |
| Apache 3 | 0.438 | 0.05 | 89 |

[1] This baseline emission rate represents operation of OFA only.

iii. Capacity Factor

As noted previously, AEPCO calculated annual emission estimates for its control scenarios, in tons per year, using annual capacity factors developed internally over an unspecified time frame.[98] The annual capacity factors AEPCO used for each unit were 92 percent (Apache 2), and 87 percent (Apache 3). We have also calculated annual emission estimates for our control scenarios using capacity factors, but have used information developed from CAMD information, and over a more recent 2008 to 2011 time frame. The annual capacity factors we have used for each unit are 62 percent (Apache 2), and 71 percent (Apache 3). We recognize that these capacity factors are lower than those used by AEPCO, and that by using these lower capacity factors, our estimates of total annual emissions (and correspondingly, the annual emission reductions) for each control scenario are lower than AEPCO's estimates.[99] Since cost-effectiveness ($/ton) is calculated by dividing annual control costs ($/year) by annual emission reductions (tons/year), the use of emission reductions based on lower capacity factors will increase the cost per ton of pollutant reduced.

We have elected to use the capacity factors specified above, as based on a 2008 to 2011 time frame, in order to remain consistent with the time frame used to develop baseline annual emissions for Apache and the other power plants that are the subject of today's proposed action.

iv. Summary of Control Cost Estimates

A summary of our control cost estimates for the various control technology options considered for Apache Units 2 and 3 is in Table 16. Detailed cost calculations, including our contractor's report and cost calculation spreadsheets, are available in our Technical Support Document.

TABLE 16—APACHE UNITS 2 AND 3: EPA'S CONTROL COST SUMMARY

| Control option | Emission factor (lb/MMBtu) | Emission rate | | Emissions removed (tpy) | Annual cost ($/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|---|---|
| | | (lb/hr) | (tpy) | | | Ave | Incremental (from previous) |
| **Apache 2** | | | | | | | |
| OFA (baseline) | 0.371 | 859 | 2,333 | | | | |
| LNB+OFA | 0.26 | 601 | 1,633 | 700 | 1,142,120 | 1,632 | |
| SNCR+LNB+OFA | 0.18 | 421 | 1,143 | 1,190 | 2,652,841 | 2,230 | 3,084 |
| SCR+LNB+OFA | 0.05 | 116 | 314 | 2,019 | 5,869,299 | 2,908 | 3,881 |

[97] BART Guidelines, 40 CFR part 51, appendix P, Section IV.D.4.d.

[98] As listed in Table 2–1 in Docket Items B–03 and B–04, Apache BART Analyses.

[99] We note that there are multiple reasons why our annual emission estimates (and estimates of emission removal) are lower than AEPCO's and ADEQ's estimates. We are not implying that the use of capacity factor is the sole, or even dominant, reason for this difference, simply that the use of lower capacity factors will result in lower annual emission estimates.

TABLE 16—APACHE UNITS 2 AND 3: EPA'S CONTROL COST SUMMARY—Continued

| Control option | Emission factor (lb/MMBtu) | Emission rate | | Emissions removed (tpy) | Annual cost ($/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|---|---|
| | | (lb/hr) | (tpy) | | | Ave | Incremental (from previous) |
| **Apache 3** | | | | | | | |
| OFA (baseline) | 0.438 | 974 | 3,028 | | | | |
| LNB+OFA | 0.31 | 682 | 2,120 | 908 | 1,153,378 | 1,270 | |
| SNCR+LNB+OFA | 0.22 | 477 | 1,484 | 1,544 | 2,968,611 | 1,922 | 2,854 |
| SCR+LNB+OFA | 0.05 | 111 | 346 | 2,683 | 6,103,078 | 2,275 | 2,754 |

As seen in Table 16, our calculations indicate that the SCR-based control options have average cost-effectiveness values of $2,275/ton to $2,908/ton, which falls in a range that we consider cost-effective. In addition, our calculations indicate that the SCR-based control options have an incremental cost-effectiveness of $2,754/ton to $3,881/ton, which is also in a range that we would consider cost-effective. As a result, our analysis of this factor indicates that the costs of compliance (average or incremental) are not sufficiently large to warrant eliminating any of the control options from consideration.

b. Visibility Improvement

The overall visibility modeling approach was described above; aspects of the modeling specific to Apache are described here. EPA is proposing a $NO_X$ BART determination only for Apache units 2 and 3, but Unit 1 was also included in the modeling runs for greater realism in assessing the full facility's visibility impacts.[100] For Unit 1's $NO_X$ emissions, ADEQ's emission factor of 0.56 lb/MMBtu was combined with the maximum MMBtu/hr heat rate from EPA's CAMD database for 2008 to 2010. The baseline emissions used for these units were the maximum daily emissions in lb/hr from 2008 to 2010; the maxima occurred in early 2008. The base case reflects only OFA as the control in place.

EPA evaluated LNB, SNCR (including LNB), and SCR (including LNB) applied to both Units 2 and 3; as mentioned above the SCR simulation accounted for the increase in sulfuric acid emissions due to catalyst oxidation of $SO_2$. SCR was assumed to give a control effectiveness of 87 percent and 89 percent for Units 2 and 3, respectively (less than 90 percent due to the 0.05 lb/MMBtu $NO_X$ lower limit assumed for SCR). The nine Class I areas within 300 km of Apache were modeled; they are in the states of Arizona and New Mexico. The 98th percentile of delta deciviews over all three years of data was computed for each area and emission scenario.

Table 17 shows the impact for the base case, and the improvement from that baseline impact when controls are applied, all in deciviews, for each area. The Class I area types are National Monument (NM), Wilderness Area (WA), and National Park (NP). Also shown are the cumulative deciviews, the simple sum of impacts or improvements over all the Class I areas, and the number of areas with a baseline impact or improvement of at least 0.5 dv. Finally, the table includes two ''dollars per deciview'' measures of cost-effectiveness, both of which take the annual cost of the control in millions of dollars per year, and divide by an improvement in deciviews. For the first metric, ''$/max dv'', cost is divided by the deciview improvement at the Class I area with the greatest improvement. The second metric, ''$/cumulative dv'', divides cost by the cumulative deciview improvement. In assessing the degree of visibility improvement from controls, EPA relied heavily on the maximum dv improvement and the number of areas showing improvement, with cumulative improvement providing a supplemental measure that combines information on the number of areas and on individual area improvement. The dollars per deciview metrics provided information supplemental to the dollars per ton that was considered in the cost factor.

In its comments on Arizona's proposed Regional Haze SIP, the National Park Service noted that:

> Compared to the typical control cost analysis in which estimates fall into the range of $2,000–$10,000 per ton of pollutant removed, spending millions of dollars per deciview (dv) to improve visibility may appear extraordinarily expensive. However, our compilation of BART analyses across the U.S. reveals that the average cost per dv proposed by either a state or a BART source is $14–$18 million.[101]

While we do not necessarily consider $14 to $18 million/dv as being a reasonable range in all cases, we note that for all of the $NO_X$ control options, including SCR, both the $/max dv and the $/cumulative dv are well below this range.

The area with the greatest dv improvement was the Chiricahua Wilderness Area; the improvement from LNB was 0.5 dv, from SNCR was 1 dv, and from SCR was 1.6 dv. Any of these improvements would contribute to improved visibility, with SCR being the superior option for visibility. The corresponding cumulative improvements are 2.1, 3.8, and 6.5. Both SNCR and SCR give improvements exceeding 0.5 dv at four areas, but for SCR the improvements at those areas also exceed a full 1 dv. The improvements from SCR are substantially greater than for the other candidate controls. The modeled degree of visibility improvement supports SCR as BART for Apache.

[100] Apache Unit 4, which consists of four simple-cycle gas turbines, was not included in the modeling because its $NO_X$ emissions are less than 1 percent of the emissions of units 2 and 3, and are therefore expected to have a *de minimis* effect on modeled visibility impacts.

[101] Arizona Regional Haze SIP, Appendix E, Public Process, NPS General BART Comments on ADEQ BART Analyses (November 29, 2010), p. 4.

TABLE 17—APACHE UNITS 2 AND 3: EPA'S VISIBILITY IMPROVEMENT FROM $NO_X$ CONTROLS

| Class I Area | Baseline impact (dv) | Improvement from LNB (dv) | Improvement from SNCR (dv) | Improvement from SCR (dv) |
|---|---|---|---|---|
| Chiricahua NM | 3.41 | 0.44 | 0.82 | 1.51 |
| Chiricahua WA | 3.46 | 0.53 | 1.00 | 1.59 |
| Galiuro WA | 2.22 | 0.39 | 0.65 | 1.10 |
| Gila WA | 0.63 | 0.14 | 0.22 | 0.37 |
| Mazatzal WA | 0.28 | 0.05 | 0.09 | 0.14 |
| Mount Baldy WA | 0.28 | 0.07 | 0.11 | 0.18 |
| Saguaro NP | 2.49 | 0.38 | 0.66 | 1.16 |
| Sierra Ancha WA | 0.29 | 0.06 | 0.10 | 0.14 |
| Superstition WA | 0.61 | 0.10 | 0.19 | 0.31 |
| Cumulative dv | 13.67 | 2.14 | 3.83 | 6.51 |
| # areas >=0.5 | 6 | 1 | 4 | 4 |
| $/max dv, millions | ........................ | $4.8 | $6.0 | $8.7 |
| $/cumulative dv, millions | ........................ | $1.2 | $1.6 | $2.1 |

c. EPA's BART Determination

In considering the results of the five-factor analysis, we note that the remaining useful life of the source, as indicated previously by the plant economic life of Apache Units 2 and 3, is incorporated into control cost calculations as a 20-year amortization period. In addition, the presence of existing pollution control technology is reflected in the cost and visibility factors as a result of selection of the baseline period for cost calculations and visibility modeling. For Apache Units 2 and 3, a baseline period (2008 to 2010) was selected that reflects the currently existing pollution control technology (OFA). In examining energy and non-air quality impacts, we note certain potential impacts resulting from the use of ammonia injection associated with the SNCR and SCR control options, but do not consider these impacts sufficient enough to warrant eliminating any of the available control technologies.

Our consideration of degree of visibility improvement focuses primarily on the improvement from base case impacts associated with each control option. While each of the available $NO_X$ control options achieves some degree of visibility improvement, we consider the improvement associated with the most stringent option, SCR with LNB and OFA, to be substantial. Our consideration of cost of compliance focuses primarily on the cost-effectiveness of each control option, as measured in cost per ton and incremental cost per ton of each control option. Despite the fact that the most stringent option, SCR with LNB and OFA, is the most expensive of the available control options, we consider it cost-effective on an average basis as well as on an incremental basis when compared to the next most stringent option, SNCR with LNB and OFA.

As a result, we consider the most stringent available control option, SCR with LNB and OFA, to be both cost-effective and to result in substantial visibility improvement, and that the energy and non-air quality impacts are not sufficient to warrant eliminating it from consideration. Therefore, the results of our five-factor analysis indicate that $NO_X$ BART for Apache Units 2 and 3 is SCR with LNB and OFA.

However, we note that the BART guidelines state that:

> Even if the control technology is cost-effective, there may be cases where the installation of controls would affect the viability of continued plant operations. […]You may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology. Where these effects are judged to have a severe impact on plant operations you may consider them in the selection process, but you may wish to provide an economic analysis that demonstrates, in sufficient detail for public review, the specific economic effects, parameters, and reasoning.'' [102]

As explained in Section IX.C below, because AEPCO is a ''small entity'', as defined under the Regulatory Flexibility Act, we have conducted an initial assessment of the potential adverse impacts on AEPCO of requiring SCR with LNB and OFA. Using publicly available information, EPA estimates that the annualized cost of requiring SCR in Units 1 and 2 would likely be in the range of 3 percent of AEPCO's assets and between 6 and 7 percent of AEPCO's annual sales. The projected costs of SCR with LNB and OFA are approximately $12 million per year. This exceeds AEPCO's net margins of $9.5 million in 2010 and $1.9 million in 2011.[103]

In addition to conducting this initial economic impact assessment, we requested information from AEPCO on the economics of operating Apache Generating Station and what impact the installation of SCR may have on the economics of operating Apache Generating Station. We have just received a description of plant conditions and potential economic effects and are placing this information in the docket for this action.[104] We will consider this information and any additional information received during the comment period as part of our final action. If our analysis of this information indicates that installation of SCR will have a severe impact on the economics of operating Apache Generating Station, we will incorporate such considerations in our selection of BART.

Nonetheless, based on the available control technologies and the five factors discussed above, EPA is proposing to require Apache Generating Station to meet an emission limit for $NO_X$ on Units 2 and 3 of 0.050 lb/MMBtu. Each of these emission limits is based on a rolling 30-boiler-operating-day average.

2. Cholla Units 2, 3 and 4

a. Costs of Compliance

Our general approach to calculating the costs of compliance is described in section VII.A.1 above. Issues unique to Cholla Units 2, 3 and 4 are explained

[102] 70 FR 39171.

[103] See Docket Item H–1Arizona Electric Power Cooperative, Inc. Annual Report Electric for Year Ending December 31, 2011 submitted to Arizona Corporation Commission Utilities Division, available at *http://www.azcc.gov/Divisions/Utilities/Annual%20Reports/2011/Electric/Arizona_Electric_Power_Cooperative_Inc.pdf.*

[104] Docket Item C–16, Letter from Michelle Freeark (AEPCO) to Deborah Jordan (EPA), AEPCO's Comments on BART for Apache Generating Station, June 29, 2012.

herein. There are several aspects of our analysis of this factor that differ from ADEQ's and APS' analysis and we discuss the most important of these below.

i. Selection of Baseline Period

APS' BART analysis used a 2001–03 time period in order to establish its baseline $NO_X$ emissions. As noted previously, the $NO_X$ control technology present on Cholla Units 2 through 4 during that time period was close-coupled over fire air (COFA). APS has since installed low-$NO_X$ burners with separated over fire air (SOFA) on Cholla Units 2 through 4. In order to properly consider the second BART factor (pollution control equipment in use at the source) and to ensure that actual conditions at the plant were reflected in our baseline $NO_X$ emissions, we decided to make use of the most recent Acid Rain Program emission data reported to CAMD, which, at the time that we began our analysis in 2011, was the three-year period from 2008 to 2010. Based on CAMD documentation, the low-$NO_X$ burners were installed on the Cholla units at different times during 2008 and 2009, making it necessary for us to clearly distinguish between the pre-LNB and post-LNB periods of emission data for each unit.

The use of a 2008 to 2010 baseline was, however, complicated by the fact that the Cholla plant operates under a new coal contract for Lee Ranch/El Segundo coal, which is a higher $NO_X$-emitting coal than what was previously used.[105] This coal contract indicates that steadily increasing minimum quantities of coal shall be delivered, starting with 325,000 tons in 2006 and up to 3,700,000 tons in 2010. This gradual transition to the newer, higher-$NO_X$ emitting coal source made it difficult to determine the extent to which a particular year's emissions were representative of anticipated annual emissions. In the absence of more detailed fuel usage records on a per-unit basis, it was not possible for us to identify which units may have operated using the newer coal during the 2006 to 2010 transition period to the newer coal type. We note, however, that the coal contract specifically states that, for 2010 to 2024, no later than July 1 of each year, the buyer shall indicate the annual tonnage for the following calendar year, and that in no case shall the annual tonnage be less than 3,700,000 tons. As a result, 2011 represents the first complete calendar year at which we can be certain that the Cholla plant operated at the new coal contract's ''full'' minimum purchase quantity of 3,700,000 tons per year.

Since 2011 Acid Rain Program emission data became available during the intervening time between the start of our analysis and our proposed action today, we have selected 2011 as the time period for establishing baseline annual $NO_X$ emissions. Although this represents only a single year of data, we believe the use of this more recent baseline period represents the most realistic depiction of anticipated annual emissions, as it is the only time period that ensures each of the Cholla units is operating using the new coal and LNB with SOFA.

ii. SCR Control Efficiency

In determining the control efficiency of SCR, we have relied upon an SCR level of performance of 0.05 lb/MMBtu, which is more stringent than the level of performance used by ADEQ in its SIP. In the Cholla BART analysis submitted to ADEQ, APS indicated an SCR level of performance of 0.07 lb/MMBtu, but did not provide site-specific information describing how this emission rate was developed or discussing why a more stringent 0.05 lb/MMBtu level of performance could not be attained. Our control cost calculations for the SCR and LNB with OFA control options are based upon the SCR control efficiencies summarized below. These control efficiencies reflect the emission reductions associated with controlling from an annual average baseline emission rate that represents LNB with OFA (as described previously) down to an SCR emission rate of 0.05 lb/MMBtu.

TABLE 18—CHOLLA UNITS 2, 3 AND 4: EPA'S SCR CONTROL EFFICIENCY

| Unit | Baseline emission rate[1] (lb/MMBtu) | SCR emission rate | SCR control efficiency (percentage) |
|---|---|---|---|
| Cholla 2 | 0.295 | 0.05 | 83 |
| Cholla 3 | 0.254 | 0.05 | 80 |
| Cholla 4 | 0.260 | 0.05 | 81 |

[1] As noted previously, this baseline emission rate reflects the installation of LNB+OFA

iii. Capacity Factor

As noted previously, APS calculated annual emission estimates for its control scenarios, in tons per year, using annual capacity factors based on Acid Rain Program data from CAMD over a 2001 to 2006 time frame.[106] The annual capacity factors APS used for each unit were 91 percent (Cholla 2), 86 percent (Cholla 3), and 93 percent (Cholla 4). We have also calculated annual emission estimates for our control scenarios using capacity factors developed from CAMD information, but have instead used a more recent 2008 to 2011 time frame. The annual capacity factors we have used for each unit are 74 percent (Cholla 2), 75 percent (Cholla 3), and 71 percent (Cholla 4). We recognize that these capacity factors are lower than those used by APS, and that by using these lower capacity factors, our estimates of total annual emissions (and correspondingly, the annual emission reductions) for each control scenario are lower than APS' estimates.[107] Since cost-effectiveness ($/ton) is calculated by dividing annual control costs ($/year) by annual emission reductions (tons/year), the use of emission reductions based on lower capacity factors will increase the cost per ton of pollutant reduced.

We have elected to use the capacity factors specified above, as based on a 2008 to 2011 time frame, in order to remain consistent with the time frame used to develop baseline annual emissions for Cholla and the other

[105] A copy of the coal contract, including obligation amounts and coal quality, can be found in Docket Item B–09, ''Additional APS Cholla BART response'', Appendix B.

[106] As listed in Table 2–1 in Docket Items B–06 through B–08, Cholla BART Analyses.

[107] We note that there are multiple reasons why our annual emission estimates (and estimates of emission removal) are lower than APS' and ADEQ's estimates. We are not implying that the use of capacity factor is the sole, or even dominant, reason for this difference, simply that the use of lower capacity factors will result in lower annual emission estimates.

power plants that are the subject of today's proposed action.[108]

iv. Summary of Control Costs

A summary of our control cost estimates for the various control technology options considered for is included below. Detailed cost calculations, including our contractor's report and cost calculation spreadsheets, can be found in our TSD.

TABLE 19—CHOLLA UNITS 2, 3 AND 4: EPA'S CONTROL COST SUMMARY

| Control option | Emission factor (lb/MMBtu) | Emission rate | | Emissions removed (tpy) | Annual cost ($/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|---|---|
| | | (lb/hr) | (tpy) | | | Ave | Incremental (from previous) |
| **Cholla 2** | | | | | | | |
| OFA | NA; LNB+OFA is the currently installed technology | | | | | | |
| LNB+OFA (baseline) | 0.295 | 892 | 2,890 | | | | |
| SNCR+LNB+OFA | 0.21 | 624 | 2,023 | 867 | 2,482,318 | 2,863 | |
| SCR+LNB+OFA | 0.05 | 151 | 490 | 2,400 | 7,475,028 | 3,114 | 3,257 |
| **Cholla 3** | | | | | | | |
| OFA | NA; LNB+OFA is the currently installed technology | | | | | | |
| LNB+OFA (baseline) | 0.254 | 885 | 2,908 | | | | |
| SNCR+LNB+OFA | 0.18 | 620 | 2,036 | 872 | 2,533,432 | 2,904 | |
| SCR+LNB+OFA | 0.05 | 174 | 572 | 2,337 | 8,113,131 | 3,472 | 3,811 |
| **Cholla 4** | | | | | | | |
| OFA | NA; LNB+OFA is the currently installed technology | | | | | | |
| LNB+OFA (baseline) | 0.260 | 1144 | 3,609 | | | | |
| SNCR+LNB+OFA | 0.18 | 801 | 2,526 | 1,083 | 3,185,822 | 2,943 | |
| SCR+LNB+OFA | 0.05 | 220 | 694 | 2,915 | 9,894,796 | 3,395 | 3,661 |

As indicated in Table 19, our calculations indicate that the SCR-based control options have average cost-effectiveness values of $3,114/ton to $3,472/ton, which falls in a range that we would consider cost-effective. In addition, our calculations indicate that the SCR-based control options have an incremental cost-effectiveness of $3,257/ton to $3,811/ton, which is also in a range that we would consider cost-effective. As a result, our analysis of this factor indicates that the costs of compliance (average or incremental) are not sufficiently large to warrant eliminating any of the control options from consideration.

b. Visibility Improvement

The overall visibility modeling approach was described above; aspects of the modeling specific to Cholla are described here. EPA made a $NO_X$ BART determination for Cholla Units 2, 3 and 4, but Unit 1 (which is not BART-eligible) was also included in the modeling runs for greater realism in assessing the full facility's visibility impacts. For Unit 1's $NO_X$ emissions, the maximum daily emissions from EPA's CAMD database for 2008 to 2010 were used; the maximum occurred in early 2008. LNB was installed on Units 2 and 4 early in 2008, and on Unit 3 in mid-2009; for a realistic base case, the baseline emissions used for these units were the maximum daily emissions in lb/hr from 2008–2010 occurring after the respective LNB installation dates. The maximum for unit 2 occurred in mid-2009, and the maxima for Units 2 and 3 occurred in late 2010. The base case reflects LNB as the control in place.

EPA evaluated SNCR (including LNB) and SCR (including LNB) applied to Units 2, 3 and 4. SCR was assumed to give a control effectiveness of 83 percent, 80 percent, and 81 percent for units 2, 3 and 4, respectively (less than 90 percent due to the 0.05 lb/MMBtu $NO_X$ lower limit assumed for SCR). For Cholla, the increase in sulfuric acid due to SCR was not simulated, because the baghouse (fabric filter) installed for particulate matter control would reduce this increased sulfate by 99 percent, resulting in a negligible effect on the visibility estimate. The 13 Class I areas within 300 km of Cholla were modeled; they are in the states of Arizona, Colorado, New Mexico, and Utah. The 98th percentile delta deciview using all three years of data together was computed for each area and emission scenario.

Table 20 shows baseline visibility impacts and the visibility improvement when controls are applied; the various table entries are described above in the discussion of the comparable table for Apache. The area with the greatest dv improvement was the Petrified Forest National Park; the improvement from SNCR was just under 0.5 dv and from SCR was 1.3 dv. Either of these improvements would contribute to improved visibility, with SCR being the superior option for visibility. The corresponding cumulative improvements are 2.7 and 7.2. Only SCR gives improvements exceeding 0.5 dv, and it does so at eight areas, two of which have improvements above a full 1 dv. The modeled degree of visibility

[108] We recognize that there are more aggressive approaches we could adopt that could justify the use of higher capacity factors, which would thereby lower the cost per ton of pollutant reduced. For example, instead of using historical data to develop a capacity factor value for each unit, we could use a single capacity factor value for each unit, one that represented a reasonable depiction of anticipated annual baseload operations. Alternately, we could also use the capacity factor estimates from APS' Cholla BART analyses, as based on a 2001–06 time frame, or develop new capacity factors based on a longer 2001 to 2011 time frame.

improvements supports SCR as BART for Cholla.

TABLE 20—CHOLLA UNITS 2, 3 AND 4: EPA'S VISIBILITY IMPROVEMENT FROM $NO_X$ CONTROLS

| Class I area | Baseline impact (dv) | Improvement from SNCR (dv) | Improvement from SCR (dv) |
|---|---|---|---|
| Capitol Reef NP | 1.46 | 0.27 | 0.76 |
| Galiuro WA | 0.45 | 0.05 | 0.14 |
| Gila WA | 0.70 | 0.09 | 0.22 |
| Grand Canyon NP | 2.22 | 0.37 | 1.06 |
| Mazatzal WA | 1.19 | 0.16 | 0.43 |
| Mesa Verde NP | 1.34 | 0.26 | 0.70 |
| Mount Baldy WA | 1.21 | 0.27 | 0.52 |
| Petrified Forest NP | 4.53 | 0.47 | 1.34 |
| Pine Mountain WA | 0.85 | 0.12 | 0.31 |
| Saguaro NP | 0.30 | 0.02 | 0.05 |
| Sierra Ancha WA | 1.36 | 0.20 | 0.51 |
| Superstition WA | 1.27 | 0.17 | 0.51 |
| Sycamore Canyon WA | 1.42 | 0.27 | 0.68 |
| Cumulative dv | 18.30 | 2.71 | 7.21 |
| # areas >=0.5 | 11 | 0 | 8 |
| $/max dv, millions | | $17.8 | $20.8 |
| $/cumulative dv, millions | | $3.1 | $3.8 |

c. EPA's BART Determination

As noted above, the remaining useful life of the source is incorporated into control cost calculations as a 20-year amortization period. In addition, the presence of existing pollution control technology is reflected in the cost and visibility factors as a result of selection of the baseline period for cost calculations and visibility modeling. For Cholla Units 2, 3, and 4, a baseline period (2011) was selected that reflects the currently existing pollution control technology (LNB with OFA). In examining energy and non-air quality impacts, we note certain potential impacts resulting from the use of ammonia injection associated with the SNCR and SCR control options, but do not consider these impacts sufficient enough to warrant eliminating any of the available control technologies.

Our consideration of degree of visibility improvement focuses primarily on the improvement from base case impacts associated with each control option. While each of the available $NO_X$ control options achieves some degree of visibility improvement, we consider the improvement associated with the most stringent option, SCR with LNB and OFA, to be substantial.

Our consideration of cost of compliance focuses primarily on the cost-effectiveness of each control option, as measured in cost per ton and incremental cost per ton of each control option. Despite the fact that the most stringent option, SCR with LNB and OFA, is the most expensive of the available control options, we consider it cost-effective on average basis as well as on an incremental basis when compared to the next most stringent option, SNCR with LNB and OFA.

As a result, we consider the most stringent available control option, SCR with LNB and OFA, to be both cost-effective and to result in substantial visibility improvement, and that the energy and non-air quality impacts are not sufficient to warrant eliminating it from consideration. Therefore, we propose to determine that $NO_X$ BART for Cholla Units 2, 3, and 4 is SCR with LNB and OFA, with an associated emission limit for $NO_X$ on each of Units 2, 3, and 4 of 0.050 pounds per million British thermal units (lb/MMBtu), based on a rolling 30-boiler-operating-day average.

3. Coronado Units 1 and 2

a. Costs of Compliance

Our general approach to calculating the costs of compliance is described in section VII.A.2 above, while considerations unique to Coronado Units 1 and 2 are explained herein. There are several aspects of our analysis of this factor that differ from ADEQ's and SRP's analysis and we describe the most important elements below.

i. Selection of Baseline Period and Baseline Control Technology

SRP's BART analysis used a 2001–03 time period in order to establish its baseline $NO_X$ emissions. Since that time period, SRP has since installed LNB with OFA on Coronado Units 1 and 2. In order to ensure that actual conditions at the plant are reflected in our baseline $NO_X$ emissions, we decided to make use of the most recent Acid Rain Program emission data reported to CAMD, which, at the time that we began our analysis in 2011, was the three-year period from CY2008–10. Based on CAMD documentation, the low-$NO_X$ burners were installed on Coronado Unit 1 on May 16, 2009, making it necessary for us to clearly distinguish between the pre-LNB and post-LNB periods of emission data for Coronado Unit 1. In our analysis, we have decided to make use of CAMD emission data corresponding to the post-LNB period extending from May 16, 2009 to December 31, 2010. We believe the use of this more recent baseline period represents the most realistic depiction of anticipated annual emissions, as it reflects operation of Coronado Unit 1 with LNB and OFA.

For Coronado Unit 2, we note that a consent decree between SRP and EPA requires the installation of SCR and compliance with an emission limit of 0.080 lb/MMBtu (30-day rolling average) by June 1, 2014.[109] Although we realize this SCR system has not yet been installed on Coronado Unit 2, this limit is federally enforceable and represents a realistic depiction of anticipated future emissions.[110] As a result, we consider 0.080 lb/MMBtu to be the baseline emission rate in our BART analysis and are examining only one control scenario

[109] See Docket Item G–01, ''Consent Decree Between U.S. and SRP (final as entered).'' See also ADEQ Title V Permit Renewal Number 52639, SRP—Coronado Generating Station, section II.E.1.a.iii (December 06, 2011).

[110] See 40 CFR part 51, appendix Y, Section IV.D.4.d.

in our analysis for Unit 2, SCR at a more stringent emission rate of 0.050 lb/MMBtu.[111]

ii. SCR Control Efficiency

In determining the control efficiency of SCR in our BART analysis, we have relied upon an SCR level of performance of 0.05 lb/MMBtu, which is more stringent than the level of performance used by ADEQ in its SIP, or by SRP in its Coronado BART analysis. In the Coronado BART analysis submitted to ADEQ, SRP indicated an SCR level of performance of 0.08 lb/MMBtu, and noted that ''If inlet $NO_X$ concentrations are less than 250 ppmvd, SCR can achieve $NO_X$ control efficiencies ranging only from 70 to 80 percent.'' [112] SRP suggests that the 75 percent reduction (and associated 0.08 lb/MMBtu emission rate) it estimates for SCR is the result of low inlet $NO_X$ concentration, but does not provide specific information regarding inlet $NO_X$ concentration at Coronado, or how a 75 percent reduction was determined. Our control cost calculations for the SCR control option at Coronado Unit 1 are based upon the SCR control efficiency summarized below. This control efficiency reflects the emission reductions associated with controlling from an annual average baseline emission rate that represents LNB+OFA (as described previously) down to an SCR emission rate of 0.05 lb/MMBtu.

TABLE 21—CORONADO UNIT 1: EPA'S SCR CONTROL EFFICIENCY

| Unit No. | Baseline emission rate (lb/MMBtu) | SCR emission rate | SCR control efficiency (percentage) |
|---|---|---|---|
| Coronado 1 | 0.303 | 0.05 | 83.5 |

iii. Capacity Factor

SRP did not calculate annual emission estimates for its control scenarios, in tons per year, in its BART analysis submitted to ADEQ. In developing its RH SIP, ADEQ estimated annual emission reductions based upon 8,760 hours/year of operation (i.e., 100 percent capacity factor). We have calculated annual emission estimates for our control scenarios using capacity factors developed over a CY2008–11 time frame. The annual capacity factors we have used for each unit are 81 percent (Coronado 1), and 89 percent (Coronado 2). We recognize that these capacity factors are lower than those used by ADEQ, and that by using these lower capacity factors, our estimates of total annual emissions (and correspondingly, the annual emission reductions) for each control scenario are lower than ADEQ's estimates.[113] Since cost-effectiveness ($/ton) is calculated by dividing annual control costs ($/year) by annual emission reductions (tons/year), the use of emission reductions based on lower capacity factors will increase the cost per ton of pollutant reduced.

We have elected to use the capacity factors specified above, as based on a 2008 to 2011 time frame, in order to remain consistent with the time frame used to develop baseline annual emissions for Coronado and the other power plants that are the subject of today's proposed action.[114]

iv. Summary and Conclusions Regarding Costs of Control

A summary of our control cost estimates for the various control technology options considered for Coronado Units 1 and 2 is in Table 22. Detailed cost calculations, including our contractor's report and cost calculation spreadsheets, are in our TSD.

TABLE 22—CORONADO UNITS 1 AND 2: EPA'S CONTROL COST SUMMARY

| Control option | Emission factor (lb/MMBtu) | Emission rate | | Emissions removed (tpy) | Annual cost ($/yr) | Cost-effectiveness ($/ton) | |
|---|---|---|---|---|---|---|---|
| | | (lb/hr) | (tpy) | | | Average | Incremental (from previous) |
| **Coronado 1** | | | | | | | |
| OFA | NA; LNB+OFA is the currently installed technology | | | | | | |
| LNB+OFA (baseline) | 0.303 | 1,308 | 4,639 | | | | |
| SNCR+LNB+OFA | 0.21 | 915 | 3,248 | 1,392 | 3,825,556 | 2,749 | |
| SCR+LNB+OFA | 0.05 | 216 | 766 | 3,874 | 9,315,313 | 2,405 | 2,212 |
| **Coronado 2** | | | | | | | |
| SCR@0.08 lb/MMBtu (baseline) | 0.08 | 319 | 1,242 | | [1] 8,721,636 | | |
| SCR@0.05 lb/MMBtu | 0.05 | 199 | 776 | 466 | 8,993,116 | | 583 |

[1] Annual cost for the baseline scenario is provided here only to allow calculation of the incremental cost associated with a control option of SCR@0.05 lb/MMBtu.

[111] A discussion of our rationale for considering SCR at an emission rate of 0.05 lb/MMBtu can be found in Section VII.A.2 (Control Effectiveness) of this notice.

[112] See Docket Item B–10, SRP Coronado BART Analysis, page 4–5

[113] We note that there are multiple reasons why our annual emission estimates (and estimates of emission removal) are lower than AEPCO's and ADEQ's estimates. We are not implying that the use of capacity factor is the sole, or even dominant, reason for this difference, simply that the use of lower capacity factors will result in lower annual emission estimates.

[114] We recognize that there are more aggressive approaches we could adopt that could justify the use of higher capacity factors, which would thereby lower the cost per ton of pollutant reduced. For example, instead of using historical data to develop a capacity factor value for each unit, we could use a single capacity factor value for each unit, one that represented a reasonable depiction of anticipated annual baseload operations. Alternately, we could also use a 100% capacity factor, or develop new capacity factors based on a longer 2001 to 2011 time frame.

For Coronado 1, our calculations indicate that the SCR-based control option has an average cost-effectiveness value of $2,405/ton and an incremental cost-effectiveness of $2,212/ton, both of which we consider cost-effective. As described further below, our analysis for Coronado 2 relied upon SCR at an emission rate of 0.08 lb/MMBtu as a baseline scenario. As a result, the only control option we examined for Coronado 2 was an SCR-based option at a more stringent level of performance, 0.05 lb/MMBtu. Our initial analysis indicates that the incremental cost-effectiveness of such an option is $583/ton, making it a control option that we would consider cost-effective. However, we received information from SRP indicating that design and construction of the SCR system for this unit are well under way. In its letter, SRP states that ''if SRP were required to abandon the current design, incur procurement losses, possibly remove foundations, and undertake new design and procurement, such steps would vastly increase the cost of the SCR retrofit.'' Since these types of additional costs were not factored into our original analysis, the average and incremental cost-effectiveness of requiring Coronado Unit 2 to meet an emissions limit of 0.050 lb/MMBtu may in fact be greater than indicated by our analysis. However, we intend to request further documentation in order to determine the extent of these costs and how they would affect our cost-effectiveness calculations. We will include all non-CBI material received in the docket for this action and will consider it as part of our final action. We are specifically interested in information from SRP concerning the number of layers of catalyst for the SCR at Unit 2, how they plan to manage replacement of the catalyst, and whether the catalyst could be installed and managed to allow Unit 2 to meet a lower emission limit than 0.08 lb/MMBtu.

Thus, our initial analysis of this factor indicates that the costs of compliance (average or incremental) are not sufficiently large to warrant eliminating any of the control options from consideration. However, we note that, based on preliminary information received from SRP, the average and incremental costs of achieving an emission rate of 0.050 lb/MMBtu at Unit 2 may be much greater than our initial analysis suggests.

b. Visibility Improvement

The overall modeling approach was described above; aspects of the modeling specific to Coronado are described here. LNB was installed on Unit 1 in mid-2009, and on Unit 2 in mid-2011. For Unit 1's $NO_X$ emissions, the maximum daily emissions in EPA's CAMD database for 2008 to 2010 was used; the maximum post-LNB installation emissions occurred in late 2010. For unit 2 emissions, the consent decree-mandated $NO_X$ emission limit of 0.08 lb/MMBtu was combined with the maximum heat rate from 2008–2010 CAMD data, which occurred in late 2008. Since this limit has a 30-day averaging time, daily emissions may be larger than the emissions EPA modeled; the emission and visibility benefit would also be larger. Thus, visibility benefits from control applied to the base case may actually be larger than presented here. The base case reflects LNB as the control in place on Unit 1, and SCR at 0.08 lb/MMBtu $NO_X$ on Unit 2.

EPA evaluated SNCR applied to Unit 1, and SCR at 0.05 lb/MMBtu applied to both Units 1 and 2. SCR was assumed to give a control effectiveness of 83.5 percent for unit 1 (less than 90 percent due to the 0.05 lb/MMBtu $NO_X$ lower limit assumed for SCR). SCR at 0.05 lb/MMBtu $NO_X$ was assumed to give a control effectiveness of 37.5 percent over the base case 0.08 lb/MMBtu. As mentioned above, the SCR simulation accounted for the increase in sulfuric acid emissions due to catalyst oxidation of $SO_2$. However, the simulation with SNCR applied to unit 1 did not account for this effect. If this additional Unit 2 sulfate were accounted for, it could make some background ammonia unavailable to form visibility-affecting particulate from Unit 1's $NO_X$ emissions, thus reducing the visibility impact and also the visibility benefit from SNCR. We expect this to have very little effect on the estimated SNCR visibility benefit, since it was computed relative to an alternative base case that likewise did not include the catalyst oxidation effect, but the visibility benefits from SNCR may thus be slightly less than reported here, weakening the case for SNCR.

Sixteen Class I areas within 300 km of Coronado were modeled; they are in the states of Arizona, Colorado, and New Mexico. A 17th area, the Bosque del Apache Wilderness Area in New Mexico, was inadvertently omitted. Since it is in the same general direction from Coronado as the Gila Wilderness Area, but farther way, visibility impacts and control benefits at Bosque del Apache are likely to be lower than for Gila, so the maximum dv benefit would not be affected by this omission. However, the cumulative impacts and benefits would be higher than reported here since Bosque del Apache is omitted from the sum. The 98th percentile delta deciviews over all three years of data were computed for each area and emission scenario.

Table 23 shows baseline visibility impacts and the visibility improvement when controls are applied; the various table entries are described above in the discussion of the comparable table for Apache. The area with the greatest dv improvement was the Gila Wilderness Area; there is an improvement of 0.3 dv from SNCR, 0.6 dv from SCR on unit 1, and 0.7 dv from SCR at 0.05 lb/MMBtu on both units. These improvements are smaller than for the other facilities because the benefit from SCR at 0.08 lb/MMBtu on unit 2 is subsumed in the baseline. Any of these improvements would contribute to improved visibility, though SNCR on unit 2 only marginally so. SCR is the superior option for visibility, with the more stringent SCR at 0.05 lb/MMBtu on unit 2 giving a slightly greater benefit than when that limit is applied only to unit 1. The cumulative improvements corresponding to the three control scenarios are 1.3 dv, 2.8 dv, and 3.1 dv. Only the SCR scenarios give improvements exceeding 0.5 dv. The modeled degree of visibility improvements supports either SCR scenario as BART for Coronado.

TABLE 23—CORONADO UNITS 1 AND 2: EPA'S VISIBILITY IMPROVEMENTS FROM $NO_X$ CONTROLS

| Class I area | Baseline impact (dv) | Improvement from SNCR on unit 1 (dv) | Improvement from SCR .05 on unit 1 (dv) | Improvement from SCR, 0.05 lb/MMBtu (dv) |
|---|---|---|---|---|
| Bandelier NM | 0.37 | 0.07 | 0.19 | 0.20 |
| Chiricahua NM | 0.20 | 0.03 | 0.07 | 0.08 |
| Chiricahua WA | 0.21 | 0.04 | 0.08 | 0.09 |
| Galiuro WA | 0.20 | 0.03 | 0.08 | 0.09 |
| Gila WA | 1.23 | 0.33 | 0.60 | 0.66 |

TABLE 23—CORONADO UNITS 1 AND 2: EPA'S VISIBILITY IMPROVEMENTS FROM $NO_X$ CONTROLS—Continued

| Class I area | Baseline impact (dv) | Improvement from SNCR on unit 1 (dv) | Improvement from SCR .05 on unit 1 (dv) | Improvement from SCR, 0.05 lb/MMBtu (dv) |
|---|---|---|---|---|
| Grand Canyon NP | 0.24 | 0.03 | 0.10 | 0.11 |
| Mazatzal WA | 0.20 | 0.03 | 0.06 | 0.07 |
| Mesa Verde NP | 0.40 | 0.10 | 0.19 | 0.20 |
| Mount Baldy WA | 0.87 | 0.16 | 0.42 | 0.44 |
| Petrified Forest NP | 1.22 | 0.22 | 0.47 | 0.56 |
| Pine Mountain WA | 0.14 | 0.02 | 0.04 | 0.05 |
| Saguaro NP | 0.12 | 0.01 | 0.03 | 0.04 |
| San Pedro Parks WA | 0.54 | 0.11 | 0.28 | 0.30 |
| Sierra Ancha WA | 0.24 | 0.04 | 0.06 | 0.07 |
| Superstition WA | 0.21 | 0.02 | 0.06 | 0.06 |
| Sycamore Canyon WA | 0.16 | 0.02 | 0.06 | 0.06 |
| Cumulative dv | 6.54 | 1.25 | 2.78 | 3.07 |
| # areas >=0.5 | 4 | 0 | 1 | 2 |
| $/max dv, millions | ........................ | $11.9 | $16.2 | $15.0 |
| $/cumulative dv, millions | ........................ | $3.1 | $3.5 | $3.2 |

**Note:** Costs of implementing SCR at 0.08 lb/MMBtu on unit 2 are not included.

c. EPA's BART Determinations

As noted above, we have considered the remaining useful life of the source by incorporating a 20-year amortization period into our control cost calculations. The presence of existing pollution control technology is reflected in the cost and visibility factors as a result of selection of the baseline period for cost calculations and visibility modeling. For Coronado Unit 1, a baseline period (May 2009 to December 2010) was selected that reflects the currently existing pollution control technology (LNB with OFA). For Coronado Unit 2, a baseline of 0.080 lb/MMBtu was selected to reflect the requirements of the consent decree decribed above. In addition, as noted above, we have received information from SRP indicating that the design and construction of SCR at Unit 2 have aleady progressed significantly. To the extent that we receive additional documentation establishing the status of this effort, we will take this information into consideration under the factors of ''costs of compliance'' and ''existing controls.''

In examining energy and non-air quality impacts, we note certain potential impacts resulting from the use of ammonia injection associated with the SNCR and SCR control options, but do not consider these impacts sufficient enough to warrant eliminating any of the available control technologies.

Our consideration of degree of visibility improvement focuses primarily on the improvement from base case impacts associated with each control option. While each of the available $NO_X$ control options achieves some degree of visibility improvement, we consider the improvement associated with the most stringent option, SCR with LNB and OFA, to be substantial. Our consideration of cost of compliance focuses primarily on the cost-effectiveness of each control option, as measured in cost per ton and incremental cost per ton of each control option. Despite the fact that the most stringent option, SCR with LNB and OFA, is the most expensive of the available control options, we consider it cost-effective on average basis as well as on an incremental basis when compared to the next most stringent option, SNCR with LNB and OFA.

As a result, we consider the most stringent available control option, SCR with LNB and OFA, to be cost-effective and to result in substantial visibility improvement, and that the energy and non-air quality impacts are not sufficient to warrant eliminating it from consideration. Therefore, we propose to determine that $NO_X$ BART for Coronado Units 1 and 2 is SCR with LNB and OFA. At Unit1 we propose an emission limit for $NO_X$ of 0.050 lb/MMBtu, based on a rolling 30-boiler-operating-day average.

At Unit 2, we propose an emission limit of 0.080 lb/MMBtu, which is consistent with the emission limit in the consent decree. We acknowledge that the emission limit of 0.080 lb/MMBtu established in the consent decree was not the result of a BART five-factor analysis, nor does the consent decree indicate that SCR at 0.080 lb/MMBtu represents BART. Nonetheless, given the compliance schedule established in the consent decree and the preliminary information received from SRP regarding the status of design and construction of the SCR system, it appears that achieving a 0.050 lb/MMBtu emission rate may not be technically feasible. Even if it is feasible, achievement of this emission rate may not be cost-effective. Therefore, we are proposing an emission limit of 0.080 lb/MMBtu as BART for $NO_X$ at Unit 2. However, if we do not receive sufficient documentation establishing that achievement of a more stringent limit is infeasible or not cost-effective, then we may determine that a more stringent limit for this unit is required in our final action.

For Coronado Unit 2, we are proposing a compliance date of June 1, 2014 for the $NO_X$ limit, consistent with the consent decree described above.

Finally, at Coronado Unit 1, we are proposing to require compliance with the $NO_X$ limit within five years of final promulgation of this FIP consistent with the compliance times for the $NO_X$ limits at the other units. However, we are seeking comment on whether a shorter compliance schedule may be practicable for this unit.

*C. Enforceability Requirements*

In order to meet the requirements of the RHR and the CAA and to ensure that the BART limits are practically enforeceable, we propose to include the following elements in the FIP:

1. Requirements for use of continuous emission monitoring systems (CEMS) (and associated quality assurance procedures) to determine compliance with $NO_X$ and $SO_2$ limits.

2. Use of 30-day rolling averaging period and definition of boiler operating day, consistent with the BART Guidelines.

3. Requirements for annual performance stack tests and implementation of Compliance Assurance Monitoring (CAM) plan to establish compliance with PM emission limits.

4. Recordkeeping and reporting requirements.

5. Requirement to maintain and operate the unit including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions.

The foregoing requirements would apply to all units.

In addition, we are proposing specific compliance deadlines for each of ADEQ's BART emissions limits that we are proposing to approve. In most instances, the control technologies required to meet these limits have already been installed. See Table 3. Therefore, we are proposing to require compliance with the applicable emissions limits for PM and $SO_2$ within 180 days of final promulgation of this FIP, except that at Cholla Unit 2, we propose to require compliance with the PM limit by January 1, 2015, consistent with ADEQ's BART determination.

Regarding $NO_X$, we propose to allow up to five years from final promulgation of this FIP for each unit subject to an emission limit consistent with SCR, with the exception of Coronado Unit 2. This proposal is based on the results of two analyses of SCR installation times, as summarized in EPA Region 6's Complete Response to Comments for NM Regional Haze/Visibility Transport FIP.[115] An analysis performed by EPA Region 6, based on a review of a number of sources, found that the design and installation of SCR took between 18 and 69 months. A separate analysis performed for the Utility Air Regulatory Group (UARG) found that it took 28 to 62 months to design and install the 14 SCRs in its sample.[116] In the case of the BART FIP for San Juan Generating Station, EPA Region 6 initially proposed to allow a three-year compliance time frame for design and installation of SCR, but ultimately allowed for a five-year compliance schedule.[117] We also note that SCR installations often trigger Prevention of Significant of Deterioration permitting requirements because they constitute physical changes to an existing emission unit that may result in increased emissions of sulfuric acid mist. Therefore, we are proposing a five-year compliance time frame, which would provide adequate time for SCR design and installation based on the high-end of the range of dates in the analyses cited above. However, we are seeking comment on whether these compliance dates are reasonable and consistent with the requirement of the CAA and the RHR that BART be installed ''as expeditiously as practicable.'' We are specifically seeking comment on whether the outage schedule for any of these units may warrant a shorter compliance schedule (up to five years). If we receive information during the comment period that establishes that a shorter compliance timeframe is appropriate for one or more of these units, we may finalize a different compliance date.

## VIII. Summary of EPA's Proposed Action

Based on the available control technologies and the five factors discussed in more detail below, EPA is proposing to require these facilities to meet $NO_X$, $PM_{10}$ and $SO_2$ emission limits as listed in Table 24. With the exception of Apache Unit 1, the $NO_X$ emission limits in Table 24 are proposed as part of EPA's FIP, based on the five factor analyses summarized in Section VII. The $PM_{10}$ and $SO_2$ emission limits in Table 24 are taken from ADEQ's BART determinations for these facilities, proposed for EPA approval in this action. EPA is seeking comment on alternative $PM_{10}$ and $SO_2$ emissions limits for Apache Generating Station Units 2 and 3; Cholla Power Plant Units 2, 3 and 4; and Coronado Units 1 and 2 as described in Section VI.B. We are also seeking comment on whether a test method other than EPA Method 201/202 should be allowed or required for establishing compliance with the $PM_{10}$ limits that we are proposing to approve. Finally, we are proposing compliance dates and specific requirements for monitoring, recordkeeping, reporting and equipment operation and maintenance for all of the units covered by this action. Our proposed compliance dates are summarized in Table 25. We are seeking comment on whether these compliance dates are reasonable and consistent with the requirement of the CAA and the RHR that BART be installed ''as expeditiously as practicable.'' We are also taking comment on whether it would be technically feasible and cost-effective for Coronado Unit 2 to meet an emissions limit of 0.050 lb/MMBtu for $NO_X$.

EPA takes very seriously a decision to disapprove a state plan. In this instance, we believe that Arizona's SIP meets the CAA requirements with respect to its $SO_2$ and $PM_{10}$ limits, but the $NO_X$ BART determinations for the coal-fired units are neither consistent with the requirements of the Act nor with BART decisions that other states have made. As a result, EPA considers that this proposed disapproval is the only path that is consistent with the Act at this time.

TABLE 24—SUMMARY OF BART EMISSION LIMITS

| Unit | Emission limitation (lb/MMBtu) (rolling 30-boiler-operating-day average) | | |
|---|---|---|---|
| | $NO_X$ | $PM_{10}$ | $SO_2$ |
| Apache Generating Station Unit 1 | 0.056 | 0.0075 | 0.00064 |
| Apache Generating Station Unit 2 | 0.050 | 0.03 | 0.15 |
| Apache Generating Station Unit 3 | 0.050 | 0.03 | 0.15 |
| Cholla Power Plant Unit 2 | 0.050 | 0.015 | 0.15 |
| Cholla Power Plant Unit 3 | 0.050 | 0.015 | 0.15 |
| Cholla Power Plant Unit 4 | 0.050 | 0.015 | 0.15 |
| Coronado Generating Station Unit 1 | 0.050 | 0.03 | 0.08 |
| Coronado Generating Station Unit 2 | 0.080 | 0.03 | 0.08 |

[115] Available on regulations.gov, docket no. EPA–R06–OAR–2010–0846, pp. 70–72. See also 76 FR at 52408–09.

[116] J. Edward Cichanowicz, Implementation Schedule for Selective Catalytic Reduction (SCR) and Flue Gas Desulfurization (FGD) Process Equipment (Oct. 10, 2010).

[117] 76 FR at 52408–09.

TABLE 25—SUMMARY OF BART COMPLIANCE DATES

| Unit | Compliance date | | |
|---|---|---|---|
| | $NO_X$ | $PM_{10}$ | $SO_2$ |
| Apache Generating Station Unit 1 | Five years | 180 days | 180 days. |
| Apache Generating Station Unit 2 | Five years | 180 days | 180 days. |
| Apache Generating Station Unit 3 | Five years | 180 days | 180 days. |
| Cholla Power Plant Unit 2 | Five years | January 1, 2015 | 180 days. |
| Cholla Power Plant Unit 3 | Five years | 180 days | 180 days. |
| Cholla Power Plant Unit 4 | Five years | 180 days | 180 days. |
| Coronado Generating Station Unit 1 | Five years | 180 days | 180 days. |
| Coronado Generating Station Unit 2 | June 1, 2014 | 180 days | 180 days. |

TABLE 26—SUMMARY OF ARIZONA'S PROPOSED BART EMISSION LIMITS

| Unit | Emission limitation (lb/MMBtu) (rolling 30-boiler-operating-day average) | | |
|---|---|---|---|
| | $NO_X$ | $PM_{10}$ | $SO_2$ |
| Apache Generating Station Unit 1 | 0.056 | 0.0075 | 0.00064 |
| Apache Generating Station Unit 2 | n/a | 0.03 | 0.15 |
| Apache Generating Station Unit 3 | n/a | 0.03 | 0.15 |
| Cholla Power Plant Unit 2 | n/a | 0.015 | 0.15 |
| Cholla Power Plant Unit 3 | n/a | 0.015 | 0.15 |
| Cholla Power Plant Unit 4 | n/a | 0.015 | 0.15 |
| Coronado Generating Station Unit 1 | n/a | 0.03 | 0.08 |
| Coronado Generating Station Unit 2 | n/a | 0.03 | 0.08 |

TABLE 27—SUMMARY OF EPA'S PROPOSED FIP BART EMISSION LIMITS

| Unit | Emission limitation (lb/MMBtu) (rolling 30-boiler-operating-day average) | | |
|---|---|---|---|
| | $NO_X$ | $PM_{10}$ | $SO_2$ |
| Apache Generating Station Unit 1 | n/a | n/a | n/a |
| Apache Generating Station Unit 2 | 0.050 | n/a | n/a |
| Apache Generating Station Unit 3 | 0.050 | n/a | n/a |
| Cholla Power Plant Unit 2 | 0.050 | n/a | n/a |
| Cholla Power Plant Unit 3 | 0.050 | n/a | n/a |
| Cholla Power Plant Unit 4 | 0.050 | n/a | n/a |
| Coronado Generating Station Unit 1 | 0.050 | n/a | n/a |
| Coronado Generating Station Unit 2 | 0.080 | n/a | n/a |

## IX. Statutory and Executive Order Reviews

### *A. Executive Order 12866: Regulatory Planning and Review*

This proposed action is not a ''significant regulatory action'' under the terms of Executive Order 12866 (58 FR 51735, October 4, 1993) and is therefore not subject to review under Executive Orders 12866 and 13563 (76 FR 3821, January 21, 2011). As discussed in detail in section C below, the proposed FIP applies to only three facilities. It is therefore not a rule of general applicability.

### *B. Paperwork Reduction Act*

This proposed action does not impose an information collection burden under the provisions of the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* Under the Paperwork Reduction Act, a ''collection of information'' is defined as a requirement for ''answers to * * * identical reporting or recordkeeping requirements imposed on ten or more persons * * *.'' 44 U.S.C. 3502(3)(A). Because the proposed FIP applies to just three facilities, the Paperwork Reduction Act does not apply. See 5 CFR 1320(c). Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An agency may not conduct or sponsor, and a person is not required to respond to a collection of information unless it displays a currently valid Office of Management and Budget (OMB) control number. The OMB control numbers for our regulations in 40 CFR are listed in 40 CFR part 9.

### *C. Regulatory Flexibility Act*

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions. For purposes of assessing the impacts of today's proposed rule on small entities, small entity is defined as: (1) A small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for profit enterprise which is independently owned and operated and is not dominant in its field. Firms primarily engaged in the generation, transmission, and/or distribution of electric energy for sale are small if, including affiliates, the total electric output for the preceding fiscal year did not exceed 4 million megawatt hours. AEPCO sold under 3 million megawatt hours in 2011. APS and SRP are not small entities. After considering the economic impacts of this proposed action on small entities, I certify that this proposed action will not have a significant economic impact on a substantial number of small entities. The FIP for the three Arizona facilities being proposed today does not impose new requirements on a substantial number of small entities. The proposed partial approval of the SIP, if finalized, merely approves state law as meeting Federal requirements and imposes no additional requirements beyond those imposed by state law. See *Mid-Tex Electric Cooperative, Inc.* v. *FERC,* 773 F.2d 327 (DC Cir. 1985). Although a regulatory flexibility analysis as specified by the RFA is not required when a rule has some impact on one small entity, EPA policy is to assess the direct adverse impact of every rule on small entities and minimize any adverse impact to the extent feasible, regardless of the magnitude of the impact or number of small entities affected.[118] Using easily available public information,[119] EPA estimates that the annualized cost of requiring SCR in Units 1 and 2 would likely be in the range of 3 percent of AEPCO's assets and between 6 and 7 percent of AEPCO's annual sales. EPA requested information from AEPCO on the economics of operating Apache Generating Station and what impact the installation of SCR may have on the economics of operating Apache Generating Station.

[118] See Docket Item A–22 Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as Amended by the Small Business and Regulatory Enforcement Fairness Act, November 2006 at 3.

[119] See Docket Item H–1 Arizona Electric Power Cooperative, Inc. Annual Report Electric for Year Ending December 31, 2011 submitted to Arizona Corporation Commission Utilities Division, available at *http://www.azcc.gov/Divisions/Utilities/Annual%20Reports/2011/Electric/Arizona_Electric_Power_Cooperative_Inc.pdf.*

### *D. Unfunded Mandates Reform Act*

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with ''Federal mandates'' that may result in expenditures to State, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more (adjusted for inflation) in any 1 year. Before promulgating an EPA rule for which a written statement is needed, section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 of UMRA do not apply when they are inconsistent with applicable law. Moreover, section 205 of UMRA allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the final rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that may significantly or uniquely affect small governments, including Tribal governments, it must have developed under section 203 of UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant Federal intergovernmental mandates, and informing, educating, and advising small governments on compliance with the regulatory requirements.

Under Title II of UMRA, EPA has determined that this proposed rule does not contain a Federal mandate that may result in expenditures that exceed the inflation-adjusted UMRA threshold of $100 million by State, local, or Tribal governments or the private sector in any 1 year. In addition, this proposed rule does not contain a significant Federal intergovernmental mandate as described by section 203 of UMRA nor does it contain any regulatory requirements that might significantly or uniquely affect small governments.

### *E. Executive Order 13132: Federalism*

Federalism (64 FR 43255, August 10, 1999) revokes and replaces Executive Orders 12612 (Federalism) and 12875 (Enhancing the Intergovernmental Partnership). Executive Order 13132 requires EPA to develop an accountable process to ensure ''meaningful and timely input by State and local officials in the development of regulatory policies that have federalism implications.'' ''Policies that have federalism implications'' is defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.'' Under Executive Order 13132, EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, and that is not required by statute, unless the Federal government provides the funds necessary to pay the direct compliance costs incurred by State and local governments, or EPA consults with State and local officials early in the process of developing the proposed regulation. EPA also may not issue a regulation that has federalism implications and that preempts State law unless the Agency consults with State and local officials early in the process of developing the proposed regulation.

This rule will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132, because it addresses the State not fully meeting its obligation to prohibit emissions from interfering with other states measures to protect visibility established in the CAA. Thus, Executive Order 13132 does not apply to this action. In the spirit of Executive Order 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicits comment on this proposed rule from State and local officials.

### *F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments*

Executive Order 13175, entitled Consultation and Coordination With Indian Tribal Governments (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications.'' This proposed rule does not have tribal implications, as specified in Executive Order 13175. It will not have substantial direct effects on tribal governments. Thus, Executive Order 13175 does not apply to this rule. EPA specifically solicits additional comment on this proposed rule from tribal officials.

*G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks*

Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks (62 FR 19885,April 23, 1997), applies to any rule that: (1) Is determined to be economically significant as defined under Executive Order 12866; and (2) concerns an environmental health or safety risk that we have reason to believe may have a disproportionate effect on children. EPA interprets EO 13045 as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it implements specific standards established by Congress in statutes. However, to the extent this proposed rule will limit emissions of $NO_X$, $SO_2$, and $PM_{10}$, the rule will have a beneficial effect on children's health by reducing air pollution.

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

This action is not subject to Executive Order 13211 (66 FR 28355 (May 22, 2001)), because it is not a significant regulatory action under Executive Order 12866.

*I. National Technology Transfer and Advancement Act*

Section 12 of the National Technology Transfer and Advancement Act (NTTAA) of 1995 requires Federal agencies to evaluate existing technical standards when developing a new regulation. To comply with NTTAA, EPA must consider and use ''voluntary consensus standards'' (VCS) if available and applicable when developing programs and policies unless doing so would be inconsistent with applicable law or otherwise impractical. The EPA believes that VCS are inapplicable to this action. Today's action does not require the public to perform activities conducive to the use of VCS.

*J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations*

Executive Order 12898 (59 FR 7629, February 16, 1994), establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

We have determined that this proposed rule, if finalized, will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority or low-income population. This proposed federal rule limits emissions of $NO_X$, from three facilities in Arizona. The partial approval of the SIP for $SO_2$, and $PM_{10}$, if finalized, merely approves state law as meeting Federal requirements and imposes no additional requirements beyond those imposed by state law.

**List of Subjects in 40 CFR Part 52**

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide, Visibility, Volatile organic compounds.

Dated: July 2, 2012.

**Jared Blumenfeld,**

*Regional Administrator, Region 9.*

Part 52, chapter I, title 40 of the Code of Federal Regulations is proposed to be amended as follows:

## PART 52—[AMENDED]

1. The authority citation for Part 52 continues to read as follows:

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

## Subpart D—Arizona

2. Add paragraph (e) to § 52.145, to read as follows:

**§ 52.145 Visibility Protection.**

* * * * *

(e) *Federal implementation plan for regional haze.*

(1) *Applicability.* This paragraph (e) applies to each owner/operator of the following coal-fired electricity generating units (EGUs) in the state of Arizona: Apache Generating Station, Units 2 and 3; Cholla Power Plant, Units 2, 3, and 4; and Coronado Generating Station, Units 1 and 2. This paragraph (e) also applies to each owner/operator of the following natural gas-fired EGU in the state of Arizona: Apache Generating Station Unit 1. The provisions of this paragraph (e) are severable, and if any provision of this paragraph (e), or the application of any provision of this paragraph (e) to any owner/operator or circumstance, is held invalid, the application of such provision to other owner/operators and other circumstances, and the remainder of this paragraph (e), shall not be affected thereby.

(2) *Definitions.* Terms not defined below shall have the meaning given to them in the Clean Air Act or EPA's regulations implementing the Clean Air Act. For purposes of this paragraph (e):

*ADEQ* means the Arizona Department of Environmental Quality.

*Boiler operating day* means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the steam-generating unit. It is not necessary for fuel to be combusted the entire 24-hour period.

*Coal-fired unit* means any of the EGUs identified in paragraph (e)(1) of this section, except for Apache Generating Station, Unit 1.

*Continuous emission monitoring system* or *CEMS* means the equipment required by 40 CFR part 75 and this paragraph (e).

*Emissions limitation or emissions limit* means the Federal emissions limitation required by this paragraph (e) and the applicable $PM_{10}$ and $SO_2$ emissions limits for Apache Generating Station, Cholla Power Plant, and Coronada Generating Station submitted to EPA as part of the Arizona Regional Haze State Implementation Plan in a letter dated February 28, 2011 and approved into the Arizona state implementation plan on [INSERT DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**].

*lb* means pound(s).

*$NO_X$* means nitrogen oxides expressed as nitrogen dioxide ($NO_2$).

*Owner(s)/operator(s)* means any person(s) who own(s) or who operate(s), control(s), or supervise(s) one more of the units identified in paragraph (e)(1) of this section.

*MMBtu* means million British thermal unit(s).

*Operating hour* means any hour that fossil fuel is fired in the unit.

*Pipeline natural gas* means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot.

*$PM_{10}$* means filterable total particulate matter less than 10 microns and the condensable material in the impingers as measured by Methods 201A and 202.

*Regional Administrator* means the Regional Administrator of EPA Region IX or his/her authorized representative.

*$SO_2$* means sulfur dioxide.

*Unit* means any of the EGUs identified in paragraph (e)(1) of this section.

(3) *Emission Limitations.* The owner/operator of each unit subject to this paragraph (e) shall not emit or cause to be emitted $NO_X$ in excess of the following limitations, in pounds per million British thermal units (lb/MMBtu). Each emission limit shall be based on a rolling 30-boiler-operating-day average, unless otherwise indicated in specific paragraphs. Apache Generating Station Unit 1 shall operate only on pipeline natural gas.

| Unit | Federal emission limit $NO_X$ |
|---|---|
| Apache Generating Station Unit 1 | 0.056 |
| Apache Generating Station Unit 2 | 0.050 |
| Apache Generating Station Unit 3 | 0.050 |
| Cholla Power Plant Unit 2 | 0.050 |
| Cholla Power Plant Unit 3 | 0.050 |
| Cholla Power Plant Unit 4 | 0.050 |
| Coronado Generating Station Unit 1 | 0.050 |
| Coronado Generating Station Unit 2 | 0.08 |

(4) *Compliance Dates.*

i. The owners/operators of each unit subject to paragraph (e) shall comply with the emissions limitations and other requirements of this paragraph (e) as expeditiously as practicable, but in no event later than the following dates:

| Unit | Compliance date | | |
|---|---|---|---|
| | $NO_X$ | $PM_{10}$ | $SO_2$ |
| Apache Generating Station, Unit 1 | [INSERT DATE FIVE YEARS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**]. | [INSERT DATE 180 DAYS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**]. | [INSERT DATE 180 DAYS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**] |
| Apache Generating Station, Unit 2 | [INSERT DATE FIVE YEARS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**]. | [INSERT DATE 180 DAYS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**]. | [INSERT DATE 180 DAYS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**] |
| Apache Generating Station, Unit 3 | [INSERT DATE FIVE YEARS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**]. | [INSERT DATE 180 DAYS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**]. | [INSERT DATE 180 DAYS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**] |
| Cholla Power Plant, Unit 2 | [INSERT DATE FIVE YEARS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**]. | January 1, 2015 | [INSERT DATE 180 DAYS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**] |
| Cholla Power Plant, Unit 3 | [INSERT DATE FIVE YEARS AFTER DATE OF PUBLICATION IN THE **Federal Register**]. | [INSERT DATE 180 DAYS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**]. | [INSERT DATE 180 DAYS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**] |
| Cholla Power Plant, Unit 4 | [INSERT DATE FIVE YEARS AFTER DATE OF PUBLICATION IN THE **Federal Register**]. | [INSERT DATE 180 DAYS AFTER DATE OF PUBLICATION IN THE **Federal Register**]. | [INSERT DATE 180 DAYS AFTER DATE OF PUBLICATION IN THE **Federal Register**] |
| Coronado Generating Station, Unit 1. | [INSERT DATE FIVE YEARS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**]. | [INSERT DATE 180 DAYS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**]. | [INSERT DATE 180 DAYS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**] |
| Coronado Generating Station, Unit 2. | June 1, 2014 | [INSERT DATE 180 DAYS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**]. | [INSERT DATE 180 DAYS AFTER DATE OF PUBLICATION OF FINAL ACTION IN THE **Federal Register**] |

(5) *Compliance determinations for $NO_X$ and $SO_2$.*

i. *Continuous emission monitoring system.*

A. At all times after the compliance date specified in paragraph (e)(4) of this section, the owner/operator of each coal-fired unit shall maintain, calibrate, and operate a CEMS, in full compliance with the requirements found at 40 CFR part 75, to accurately measure $SO_2$, $NO_X$, diluent, and stack gas volumetric flow rate from each unit. Apache Unit 1 $NO_X$ and diluent CEMs shall be operated to meet the requirements of Part 75. Valid data means data recorded when the CEMS is not out-of-control as defined by Part 75. All valid CEMS hourly data shall be used to determine compliance with the emission limitations for $NO_X$ and $SO_2$ in paragraph (e)(3) of this section for each unit. When the CEMS is out-of-control as defined by Part 75, that CEMs data shall be treated as missing data and not used to calculate the emission average.

B. The owner/operator of each unit shall comply with the quality assurance procedures for CEMS found in 40 CFR part 75. In addition to these Part 75 requirements, relative accuracy test audits shall be performed for both the $NO_X$ pounds per hour measurement and the heat input measurement. These shall have relative accuracies of less than 20%. This testing shall be evaluated each time the CEMS undergo relative accuracy testing. Heat input for Apache Unit 1 shall be measured in accordance with Part 75 fuel gas measurement procedures found in Part 75 Appendix D.

ii. *Compliance determinations for $NO_X$.*

A. The 30-day rolling average $NO_X$ emission rate for each unit shall be calculated in accordance with the following procedure: First, sum the total pounds of $NO_X$ emitted from the unit during the current boiler operating day and the previous twenty-nine (29) boiler-operating days; second, sum the total heat input to the unit in MMBtu during the current boiler operating day and the previous twenty-nine (29) boiler-operating days; and third, divide the total number of pounds of $NO_X$ emitted during the thirty (30) boiler-operating days by the total heat input during the thirty (30) boiler-operating days. A new 30-day rolling average $NO_X$ emission rate shall be calculated for each new boiler operating day. Each 30-day rolling average $NO_X$ emission rate shall include all emissions that occur during all periods within any boiler operating day, including emissions from startup, shutdown, and malfunction.

B. If a valid $NO_X$ pounds per hour or heat input is not available for any hour for a unit, that heat input and $NO_X$ pounds per hour shall not be used in the calculation of the 30-day rolling average. Each unit must obtain valid hourly data for at least 90% of the operating hours for each calendar quarter.

iii. *Compliance determinations for $SO_2$.*

A. The 30-day rolling average $SO_2$ emission rate for each coal-fired unit shall be calculated in accordance with the following procedure: First, sum the total pounds of $SO_2$ emitted from the unit during the current boiler operating day and the previous twenty-nine (29) boiler-operating days; second, sum the total heat input to the unit in MMBtu during the current boiler-operating day and the previous twenty-nine (29) boiler-operating day; and third, divide the total number of pounds of $SO_2$ emitted during the thirty (30) boiler-operating days by the total heat input during the thirty (30) boiler-operating days. A new 30-day rolling average $SO_2$ emission rate shall be calculated for each new boiler operating day. Each 30-day rolling average $SO_2$ emission rate shall include all emissions that occur during all periods within any boiler-operating day, including emissions from startup, shutdown, and malfunction.

B. If a valid $SO_2$ pounds per hour or heat input is not available for any hour for a unit, that heat input and $SO_2$ pounds per hour shall not be used in the calculation of the 30-day rolling average. Each unit must obtain valid hourly data for at least 90% of the operating hours for each calendar quarter.

(6) *Compliance Determinations for Particulate Matter.* Compliance with the particulate matter emission limitation for each coal-fired unit shall be determined from annual performance stack tests. Within sixty (60) days of the compliance deadline specified in paragraph (e)(4) of this section, and on at least an annual basis thereafter, the owner/operator of each unit shall conduct a stack test on each unit to measure PM–10 using 40 CFR part 51, appendix M, Method 201A/202. A test protocol shall be submitted to EPA a minimum of 30 days prior to the scheduled testing. Each test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. Results shall be reported in lb/MMBtu using the calculation in 40 CFR part 60 appendix A Method 19. In addition to annual stack tests, owner/operator shall monitor particulate emissions for compliance with the emission limitations in accordance with the applicable Compliance Assurance Monitoring (CAM) plan developed and approved in accordance with 40 CFR part 64. The averaging time for any other demonstration of the PM–10 compliance or exceedance shall be based on a 6-hour average.

(7) *Recordkeeping.* The owner or operator of each unit shall maintain the following records for at least five years:

a. All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results.

b. Daily 30-day rolling emission rates for $NO_X$ and $SO_2$ for each unit, calculated in accordance with paragraph (e)(5) of this section.

c. Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR part 75.

d. Records of the relative accuracy test for $NO_X$ and $SO_2$ lb/hr measurement and hourly heat input.

e. Records of all major maintenance activities conducted on emission units, air pollution control equipment, and CEMS.

f. Any other records required by 40 CFR part 75.

(8) *Reporting.* All reports and notifications under this paragraph (e) shall be submitted to the Director of Enforcement Division, U.S. EPA Region IX, at 75 Hawthorne Street, San Francisco, CA 94105.

a. The owner/operator shall notify EPA within two weeks after completion of installation of combustion controls or Selective Catalytic Reactors on any of the units subject to this section.

b. Within 30 days after the applicable compliance date(s) in paragraph (e)(4) of this section and within 30 days of the end of each calendar quarter thereafter, the owner/operator of each unit shall submit a report that lists the daily 30-day rolling emission rates for $NO_X$ and $SO_2$ for each unit, calculated in accordance with paragraph (e)(5) of this section. Included in this report shall be the results of any relative accuracy test audit performed during the calendar quarter.

(9) *Enforcement.* Notwithstanding any other provision in this implementation plan, any credible evidence or information relevant as to whether the unit would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed, can be used to establish whether or not the owner or operator has violated or is in violation

of any standard or applicable emission limit in the plan.

(10) *Equipment Operations.* At all times, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and operate the unit including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Regional Administrator which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the unit.

(11) *Affirmative Defense for Malfunctions.* The following regulations are incorporated by reference and made part of this federal implementation plan: Rules R18–2–310 and R18–2–310.01, approved into the Arizona SIP at 40 CFR 52.120(c)(97)(i)(A).

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