UNITED STATES COURT OF APPEALS

FOR THE NINTH CIRCUIT

STATE OF ARIZONA, ex rel. HENRY R. DARWIN, Director, ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY,

Petitioner,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY and BOB PERSCIASEPE, Acting Administrator, United States Environmental Protection Agency,[1]

Respondents.

Case No. 13-70366

MOTION FOR STAY OF FINAL RULE

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INTRODUCTION

Congress gave States—not the U.S. Environmental Protection Agency—the responsibility and authority for developing programs to improve visibility at national parks and wilderness areas ("Class I areas"). *See* 42 U.S.C. § 7491(b); *Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1, 8-9 (D.C. Cir. 2002) ("*Corn Growers*"). In developing those programs, States—not EPA—must consider the costs and benefits of imposing additional environmental regulations to determine the "best available retrofit technology" ("BART") for certain types of industrial facilities. Although the statute requires States to consider five specific factors in their analysis and provides EPA with the authority to disapprove plans that do not consider those factors, States remain the ultimate decision makers. *Corn Growers* vacated EPA's original regional haze regulations because they unlawfully constrained state authority in favor of a less discretionary, more generic process that would have imposed more aggressive controls than States might have deemed warranted on a case-by-case review. *Corn Growers*, 291 F.3d at 8-9.

In the EPA rule under review here,[2] EPA ignores the statute once again by disapproving Arizona's BART determinations for seven electric generating units, even while conceding that Arizona considered all five BART factors and

[2] *Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans*, 77 Fed. Reg. 72,512 (Dec. 5, 2012).

notwithstanding that Arizona's plan would significantly improve visibility at a significant cost. EPA claims that Arizona's plan is contrary to certain Guidelines that EPA adopted under 42 U.S.C. § 7491(b), but EPA mischaracterizes those Guidelines to achieve its intended result. In any event, the BART standards in Arizona's plan are at least as stringent as the Guidelines recommend. EPA replaced Arizona's SIP by adopting a federal implementation plan ("FIP") to impose a generic BART analysis that would cost Arizona's utilities and their consumers hundreds of millions of dollars but would achieve no perceptible improvement in visibility as compared with Arizona's plan. EPA's actions demonstrate that EPA still views BART as its opportunity to impose more ambitious regulations than a State deems appropriate—no matter the cost.

This Court should stay EPA's action in disapproving Arizona's plan and imposing a federal plan because EPA's unauthorized action will impose significant irreparable harm to Arizona electricity consumers—indeed it threatens the existence of Arizona's rural-electric, consumer-owned utility—before this Court can resolve the State of Arizona's petition for review. EPA opposes this motion.

BACKGROUND

Section 7491 establishes an ambitious "goal"—eliminate "manmade" visibility impairment in national parks and wilderness areas. 42 U.S.C. § 7491(a)-(b). Recognizing the challenges associated with this aspirational objective, EPA established a deadline of 2064 for achieving it and issued regulations requiring States to submit "state implementation plans" ("SIPs") containing measures for making "reasonable progress" during the first ten-year "planning period" of the program (*i.e.*, through 2018). *See* 40 C.F.R. § 51.308(d) & (f)

In their visibility plans, the States must determine whether to impose BART controls on certain types of facilities that were in existence between 1962 and 1977. The decision to impose BART depends on whether those sources cause or contribute to any visibility impairment. If so, States must make BART determinations based on their consideration of five factors: "[1] the costs of compliance, [2] the energy and nonair quality environmental impacts of compliance, [3] any existing pollution control technology in use at the source, [4] the remaining useful life of the source, and [5] the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology." 42 U.S.C. §§ 7491(b)(2), 7491(g)(2).

The statute uses the phrase "*as determined by the State*" twice in the same paragraph to make it perfectly clear that it is the States that must consider the statutory factors and determine whether a source contributes to impairment and, if so, how to address that impairment. *See* 42 U.S.C. § 7491(b)(2)(A) (emphasis added); *see also Corn Growers*, 291 F.3d at 8 (citing strong legislative history to "confirm[ ] that Congress intended the states to decide which sources impair visibility and what BART controls should apply to those sources"). Only if a State does not submit a regional haze plan or submits a deficient plan that fails to consider the statutory factors may EPA impose a "federal implementation plan" ("FIP"), and then only ***after*** specifically identifying the alleged failure and giving the State a chance to correct it. 42 U.S.C. §§ 7491(b)(2)(A), 7410(c)(1).

EPA first adopted regulations addressing visibility impairment from "regional haze" in 1999 and set forth two options for States. Most States were required to determine BART under EPA's "Section 308" regulations. 40 C.F.R. § 51.308. However, in light of the special consideration that Congress gave to the western region known as the "Colorado Plateau," ***see*** 42 U.S.C. §§ 7492(c) & (f), EPA also adopted "Section 309" regulations to allow western States to develop an alternative program in lieu of BART, so long as the program would result in greater visibility improvements. 40 C.F.R. § 51.309. Arizona, which has been a leader in promoting visibility improvement, complied with these regulations by submitting a Section 309 regional haze SIP on December 23, 2003, and by supplementing the plan on December 31, 2004. Declaration of Eric C. Massey ("Massey Decl.") (Exh. A hereto), ¶ 1, 5. The SIP relied on an alternative program developed in coordination with four other western States. *Id*. Because EPA took no action on that SIP, it was deemed complete by operation of law six months later under 42 U.S.C. § 7410(k)(1). *Id.* at ¶ 6. EPA also missed its deadline for taking action to approve or disapprove Arizona's SIP under 42 U.S.C. § 7410(k)(2). *Id.*

While Arizona was preparing its SIP and awaiting approval, EPA's regional haze program was thrown into disarray after the D.C. Circuit first vacated the Section 308 BART program in 2002 and then, in 2005, vacated critical elements of the Section 309 program. *See Corn Growers*, 291 F.3d at 1; *Ctr. for Energy & Econ. Dev. v. EPA*, 398 F.3d 653 (D.C. Cir. 2005) ("*CEED*"); Massey Decl., ¶ 8. In response to *Corn Growers*, EPA promulgated new regional haze regulations in 2005. 70 Fed. Reg. 39,104 (July 6, 2005). These regulations also included "BART Guidelines," adopted under the last sentence of Section 7491(b), that are applicable to BART determinations for electric generating units located at powerplants in excess of 750 megawatts (MW). The new regulations required States to submit their regional haze plans by December 17, 2007. *See* 40 C.F.R. § 51.308(b). However, EPA did not revise its Section 309 regulations in response to *CEED* until late 2006. *See* 71 Fed. Reg. 60,612 (Oct. 13, 2006). As a result, Arizona and other western States had little more than one year to develop a new alternative program under Section 309 by the December 17, 2007, deadline. Due to continuing uncertainties in EPA's program, none of the western States were able to submit new Section 309 plans by December 17, 2007, although Arizona, following discussions with EPA, submitted additional copies of its original Section 309 plan to EPA on December 14, 2008. Massey Decl., ¶ 14.

Indeed, given the uncertainty associated with the regional haze program, most States failed to submit any plan by December 17, 2007. *See id.* at ¶ 15. Then, on January 15, 2009, without notice-and-comment rulemaking, EPA issued a "Finding" that 37 States had failed, in whole or in part, to submit timely plans. 74 Fed. Reg. 2,392 (Jan. 15, 2009). Arizona was included in the Finding based on EPA's assertion that Arizona's plan lacked two elements that Section 309 required, *id.* at 2,393, even though Arizona's Section 309 plan had been deemed complete by operation of law years earlier under 42 U.S.C. § 7410(k)(1). Massey Decl., ¶ 6.

Concerned that EPA would usurp Arizona authority by promulgating a FIP, but without waiving its position that it had already submitted a timely regional haze plan, Arizona submitted a new plan to EPA on February 28, 2011, under Section 308. Massey Decl., ¶ 20. But EPA still didn't act on either Arizona's Section 308 or Section 309 plan. Then, to resolve a citizens suit brought to compel EPA to act, EPA entered into a consent decree on June 21, 2012, establishing extremely tight deadlines for EPA to propose and finalize action on the States named in its 2009 Finding. *Nat'l Parks Conservation Ass'n v. EPA,* No. 1:11-cv-0158 (D.D.C. June 21, 2012). For Arizona, the consent decree required EPA either to approve Arizona's SIP or to promulgate a FIP for any disapproved portions of the SIP by November 15, 2012. *Id.* ¶ 4, Table A; Massey Decl., ¶ 28. Arizona intervened in the case out of concern that EPA would interpret the consent decree deadlines as requiring EPA to simultaneously impose a FIP if EPA in the future found deficiencies in Arizona's Section 308 SIP. Massey Decl., ¶ 24-25. The District Court, however, entered the consent decree, and Arizona has appealed. *Nat'l Parks Conservation Ass'n v. EPA*, No. 12-5211 (D.C. Cir.).

On November 15, 2012, in the action under review here, EPA partially disapproved Arizona's Section 308 plan by disapproving the BART determinations for nitrogen oxide ("NO_X") emissions from seven electric generating units at three powerplants. EPA claimed that the BART determinations were inconsistent with its Guidelines—even though Arizona's plan followed the Guidelines and imposed emission limits consistent with the "presumptive" BART emission limits contained in the Guidelines, Massey Decl., ¶ 20, and even though those Guidelines are not applicable to two of the units (at the Apache station) because they are located at a powerplant that is less than 750 MW. *See* EPA Technical Support Document (Exh. B hereto), at 13, Table 3; 40 C.F.R. Part 51. EPA also issued the disapproval without considering whether Arizona's plan as a whole would achieve "reasonable progress" towards natural visibility levels. 77 Fed. Reg. at 72,534.[3]

[3] EPA deferred action on the rest of Arizona's Section 308 SIP. *Id*. at 72,513.

To fill the gap its disapprovals left, EPA prepared its own BART determinations for the facilities. 77 Fed. Reg. at 72,514. The emission limits imposed are incredibly stringent—they require emission reductions that even *new* facilities, much less retrofits at existing facilities, cannot achieve. *See* 77 Fed. Reg. at 72,528; Massey Decl., ¶ 33. Moreover, the controls EPA assumed in its analysis will cost hundreds of millions of dollars. *See* Exhs. D and E hereto, and Aff. of Patrick F. Ledger ("Ledger Aff.") (included as Exh. A in *AEPCO v. EPA*, 13-70396 (9th Cir. filed Feb. 1, 2013) Docket Entry 9-2)). Despite this massive cost, Arizona's analysis reveals that the controls required by EPA's plan will only yield a visibility improvement of less than 0.5 "deciviews," *see* Arizona Section 308 SIP (Exh. E hereto), App. D, at 65, 77-78, 112, which will be imperceptible to the naked eye, *see* 70 Fed. Reg. at 39,119 n.28 ("a 0.5 deciview change in visibility is linked to 'perceptibility,' or a just noticeable change in most landscapes"). Arizona has requested that EPA impose an administrative stay and initiate reconsideration of its decision in light of these concerns, but it has not yet received a response. Massey Decl., ¶ 36.

ARGUMENT

I. Standard of Review

In this Circuit, "[a] party seeking a stay must establish that he is likely to succeed on the merits, that he is likely to suffer irreparable harm in the absence of relief, that the balance of equities tips in his favor, and that a stay is in the public interest." *Humane Soc'y v. Gutierrez*, 558 F.3d 896, 896 (9th Cir. 2009) (citing *Winter v. Natural Res. Def. Council, Inc.*, 555 U.S. 7 (2008)). Of these four factors, "[t]he first two factors of the traditional standard are the most critical." *Nken v. Holder*, 556 U.S. 418, 434 (2009). This Court also recognizes a sliding-scale approach under which, so long as the other two factors are also satisfied, "'[a] preliminary injunction is appropriate when a plaintiff demonstrates . . . that serious questions going to the merits were raised and the balance of hardships tips sharply in the plaintiff's favor.'" *Alliance for the Wild Rockies v. Cottrell*, 632 F.3d 1127, 1134-35 (9th Cir. 2011) (omission in original) (quoting *Lands Council v. McNair*, 537 F.3d 981, 987 (9th Cir. 2008)); *see also Alaska Survival*, No. 12-70218, 2012 U.S. App. LEXIS 24428, *2 (9th Cir. Nov. 28, 2012) (considering a motion under Fed. R. App. P. 18 and citing *Alliance for the Wild Rockies v. Cottrell*, 632 F.3d 1127 (9th Cir. 2011), for the standard of review for a motion for stay pending appeal under Fed. R. App. P. 8).

II. A Stay of EPA's Regional Haze Plan for Arizona Is Warranted

A. Arizona Is Likely to Succeed on the Merits

1. EPA usurped State authority

EPA concedes that Arizona's Section 308 SIP considered the statutory factors and followed the general process set forth in EPA's BART Guidelines. 77

Fed. Reg. 42,834, 42,840-41 (July 20, 2012). Yet, EPA justified its disapproval based on the claim that the States' BART analysis was contrary to the Guidelines, specifically: (a) Arizona's calculations of the cost of pollution controls under the first Section 7491(g)(2) factor included costs that a generic EPA manual does not address, (b) Arizona's visibility assessment under the fifth Section 7491(g)(2) factor did not consider "cumulative" impacts, and (c) Arizona did not sufficiently "weigh" the BART factors or explain its conclusions. ***Id.***

In the first place, the Guidelines are expressly not mandatory for electric generating units at powerplants that are less than 750 MW and therefore cannot be the basis for disapproving the State's BART determination for the Apache units which are located at a powerplant less than 750 MW. *See* 42 U.S.C. § 7491(b); BART Guidelines, 70 Fed. Reg. at 39,158 ("For sources other than 750 MW power plants, . . . States retain the discretion to adopt approaches that differ from the guidelines."); 77 Fed. Reg. at 72,565 n.222 (conceding BART Guidelines not binding on Apache). Moreover, EPA both reads into the BART Guidelines requirements that do not exist and ignores the fact that the NO_X emissions limits set forth in Arizona's plan conform to those that EPA recommends in its Guidelines. Massey Decl., ¶ 20. In reality, EPA simply disagrees with the conclusions that Arizona reached based on the State's consideration of the statutory BART factors and wishes to impose more stringent emission controls than Arizona deems appropriate. But, as set forth in *Corn Growers*, the judgments called for in Section 7491(b) are for the States, not EPA, to make. 291 F.3d at 6.

a. EPA erred in excluding control costs. According to EPA's BART Guidelines, States should use "appropriate supporting information" to calculate control costs and should document those calculations "either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as [EPA's Control Cost Manual])." 70 Fed. Reg. at 39,166 (emphasis added). Although the Guidelines indicate that the Manual should be used "where possible," id., the Manual is generic and cannot supply the site-specific information necessary for case-by-case BART determinations. *See* EPA Air Pollution Control Cost Manual, at 1-4 (6th Ed. Jan. 2002) ("Manual") (excerpts attached hereto as Exh. F). The Manual is also outdated (it was last updated in 2002) and fails to address certain types of costs that sources in some industries must consider in planning for significant capital expenditures. Id. at 1-3.

Since BART must be determined on a case-by-case basis by considering retrofit costs and potential visibility improvements those controls will create, Arizona relied on the best information available from actual pollution control equipment vendors and from the utilities that must actually engineer, finance, purchase, install, and operate the equipment. *See* Arizona Section 308 SIP at 140. As discussed in the Massey Declaration, it is Arizona's consideration of these real-world costs—costs that Arizona electricity consumers will actually pay to address visibility impairment—that EPA claims is erroneous. 77 Fed. Reg. at 72,516-17; Massey Decl., ¶ 30. EPA's disapproval of Arizona's BART analysis suggests that EPA now considers the Manual to be a hermetically sealed set of cost-evaluation principles requiring states to ignore any more accurate or complete site-specific information that may be available. Neither the BART Guidelines nor the Manual—and certainly nothing in the statute—compels such an illogical result. Indeed, the Manual itself specifically recognizes that it "does not directly address the controls needed to control air pollution at electrical generating units" (Manual at 1-3); that it is best suited for regulatory development using generic information, not for site-specific, cost-effectiveness determinations for individual facilities (*id.* at 1-4); and that customization is both expected and necessary to develop more accurate assessments (*id.*). *See also* Massey Decl., ¶ 30(a)).

Thus, ironically, EPA condemns Arizona for doing exactly what the Guidelines and the Manual contemplate—using the best information available to customize the analysis for each facility. EPA's response to these criticisms is that the Manual ensures consistency from state to state. 77 Fed. Reg. at 72,517-18. But if Congress had intended to require consistency from state to state, it would have given EPA authority to impose uniform standards, as it already authorized for other programs. *See, e.g.,* 42 U.S.C. § 7411(b) (authorizing EPA to set uniform technology-based standards for new units); *see also Cent. Bank of Denver v. First Interstate Bank*, 511 U.S. 164, 176-77 (1994) (recognizing that the presence of language in one part of a statute but not in another indicates that Congress "knew how to" legislate in a particular way "when it chose to do so"). In Section 7491, however, Congress contemplated that each State would exercise its judgment using the best information available, regardless of consistency. *See Train v. NRDC*, 421 U.S. 60, 79 (1975) (stating that EPA "is relegated by the Act to a secondary role" in implementing air quality standards on a state-by-state basis).

b. EPA erred in rejecting Arizona's visibility assessment. EPA condemns Arizona's analysis for allegedly failing to examine the degree of visibility impairment at all affected Class I areas and instead focusing on the maximum daily visibility impact predicted at the single most impacted Class I area. 77 Fed. Reg. at 72,519. On the contrary, Arizona's analysis considered the potential impact to all Class I areas within 300 kilometers of each facility. Massey Decl., ¶ 30. EPA's claim appears to be that Arizona violated the BART Guidelines by failing to add each Class I area's maximum daily impacts together to calculate a "cumulative" impact. 77 Fed. Reg. at 42,841. EPA also claims that the State failed to add together the effects on visibility that each unit causes. *Id.* The Guidelines, however, do not mandate use of a cumulative analysis in assessing visibility improvement from controls or use of any particular methodology at all.

70 Fed. Reg. at 39,170 ("You [States] have *flexibility* to assess visibility improvements due to BART *by one or more methods*.") (emphasis added). Indeed, the Guidelines specifically authorize States to focus on the maximum impact at a single area. *Id.* ("If the highest modeled effects are observed at the nearest Class I area, *you may choose not to analyze the other Class I areas* . . . ."). Thus, Arizona's visibility analysis is not inconsistent with the Guidelines and was therefore within the State's discretion.

c. EPA erred by determining that Arizona failed to adequately explain its BART conclusions. In its final attempt to justify its disapproval, EPA claims that Arizona failed to explain how it "weighed" the five factors that the statute required it to "consider." 77 Fed. Reg. 72,519. The statute, however, does not require States to weigh any one factor more heavily than another or establish bright-line thresholds to guide their analyses. 77 Fed. Reg. at 72,533 ("[W]e note that the BART Guidelines do not require the development of a specific threshold."). Although EPA favors its own "weighing" of the factors, in the end both EPA and Arizona considered the five BART factors and simply reached different conclusions. Under Section 7491(b), however, EPA cannot substitute its judgment for Arizona's. *Corn Growers*, 291 F.3d at 6 ("Although no weights were assigned, the factors were meant to be considered together *by the states*." (emphasis added)).

2. EPA was not authorized to impose a FIP simultaneously with its disapproval of Arizona's Section 308 SIP

Under 42 U.S.C. § 7410(c)(1), EPA may issue a FIP only *after* it makes one of three findings: (1) a State failed to make a required SIP submission, (2) the submitted SIP was incomplete, or (3) EPA disapproved a SIP in whole or in part. Moreover, EPA must give States at least some time (up to two years) to address any such findings before it can impose a FIP. *Id.* These prerequisites to EPA's FIP authority ensure that EPA provides States with an opportunity to "correct[] the deficiency" before supplanting a state's judgment with its own. *Id.*

In the action here, EPA eliminated any opportunity for Arizona to address the deficiencies that it had identified because EPA *simultaneously* disapproved Arizona's BART analysis and imposed a FIP. EPA stated that it would prefer giving Arizona time to correct the deficiencies, 77 Fed. Reg. at 42,836, but concluded that it was legally prevented from doing so because the two-year "FIP clock" initiated by its January 2009 Finding had already expired, and it was obligated to act by the consent decree deadline. 77 Fed. Reg. at 72,571.

But, in relying on its January 2009 Finding (and the consent decree that grew out of that Finding) to deny Arizona its statutory right to correct SIP deficiencies, EPA misconstrued the law and so must be reversed. *See SEC v. Chenery Corp.*, 318 U.S. 80, 95 (1943); *Prill v. NLRB*, 755 F.2d 941, 947-48 (D.C. Cir. 1985) (holding that an agency's misconception of its discretion requires a

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remand). EPA's January 2009 Finding applied only to Arizona's Section 309 SIP and did not, by its own terms, apply to EPA's Section 308 SIP, which was not even filed until two years later. Massey Decl., ¶ 15. Moreover, although EPA's January 2009 Finding was based on EPA's conclusion that Arizona's Section 309 SIP was incomplete, ***id.*** at ¶ 15, that SIP had been deemed complete by operation of law more than four years before. Id., ¶ 6. Thus, until EPA disapproved Arizona's Section 308 SIP in the action under review here, EPA had not validly made any of the three findings listed above for the State's Section 308 SIP. Accordingly, contrary to EPA's legal analysis, it was required to give Arizona up to two years to correct the deficiencies before imposing a FIP.[4]

B. Absent a Stay, the State of Arizona will Suffer Irreparable Harm

As explained by the owners of the electric generating facilities subject to EPA's FIP, the FIP will impose over half a billion—$559,500,000—in control costs. Exh. C hereto, ¶¶ 5 & 11; Exh. D hereto, ¶ 24; and Ledger Aff., ¶¶ 10 & 11. In addition to these capital costs, EPA's plan would impose millions of dollars of additional annual operating costs for each facility. *See, e.g.*, Exh. C hereto, ¶ 5. Because of long engineering and equipment-purchase lead times, EPA's December 5, 2017 compliance deadline threatens the viability of the Apache plant, Ledger

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[4] The issues that Arizona raises on this point overlap with arguments it is making in its appeal of the consent decree in the D.C. Circuit. EPA is arguing in the D.C. Circuit that these issues must be litigated in the context of the State's appeal of the FIP here. EPA's Response Brief, Exhibit G hereto, at 19-23.

Aff. ¶ 25, and will force Cholla and Coronado to incur nearly $20 million before this case can be resolved on the merits (likely late 2014): Exh. C, ¶ 8, 11, Ex. 2; Exh. D hereto, ¶ 24. Unless this Court stays EPA's action, Arizona electricity consumers will bear this $20 million burden or more. Since neither the utilities nor the public could ever recover these costs from EPA, the damage would be irreparable. *See, e.g., Cal. Pharmacists Ass'n v. Maxwell-Jolly*, 563 F.3d 847, 852 (9th Cir. 2009) (holding that monetary injury is irreparable where sovereign immunity prevents recovery), *vacated and remanded on other grounds, Douglas v. Indep. Living Ctr. of S. Cal., Inc.*, 132 S. Ct. 1204 (2012); *see also Ariz. Hosp. & Healthcare Ass'n v. Betlach*, 865 F. Supp. 2d 984, 998 (D. Ariz. 2012) (continuing to apply *California Pharmacists* after *Douglas*).

In addition, the FIP represents a considerable injury to state sovereignty by eliminating Arizona's authority over its regional haze program. This Court and others have recognized that harms to state sovereignty are irreparable. *See, e.g., Coal for Econ. Equity v. Wilson*, 122 F.3d 718, 719 (9th Cir. 1997) ("[I]t is clear that a state suffers irreparable injury whenever an enactment of its people or their representatives is enjoined."); *Kansas v. United States*, 249 F.3d 1213, 1227-28 (10th Cir. 2001) ("[B]ecause the State of Kansas claims the [decision at issue] places its sovereign interest and public policies at stake, we deem the harm the State stands to suffer as irreparable if deprived of those interests without first having a full and fair opportunity to be heard on the merits.”). The harm to Arizona’s sovereignty is particularly significant given EPA’s continued efforts to constrain Arizona’s authority in two other recently proposed actions, partially disapproving portions of Arizona’s remaining Section 308 SIP and disapproving Arizona’s Section 309 SIP (a decade after submission). Massey Decl., ¶¶ 34, 37.

C. The Real and Irreparable Harm to Arizona Outweighs Any Potential Risk of Harm from a Stay

The harm associated with the immediate actions necessary to implement EPA’s unauthorized rule will be considerable, unavoidable, and very real, whereas the harm associated with a delay in EPA’s rule will be only minimal, theoretical, and aesthetic in nature. Thus, the third factor for a stay is easily satisfied.

The summary of irreparable harm above illustrates the real impact that the FIP will have on the State of Arizona and its citizens. The $20 million in costs will fall on Arizona citizens, including many fixed- and low-income individuals, and on Arizona businesses, thereby impacting the overall economy and labor markets in a time of high unemployment. Indeed, absent a stay Arizona’s rural electric cooperative utility may not be able to survive. *See* Arizona Electric Power Cooperative March 15, 2013 motion for stay in Docket No. 13-70396. Although the harm to Arizona’s sovereignty is immeasurable, it is no less real, particularly in light of EPA’s continuing efforts to limit the State’s authority over its regional haze program. Without a stay, these irreparable harms are a certainty.

The potential harm associated with a stay of EPA's action is quite different. The only potential harm associated with a stay would be to delay by perhaps two years controls designed to achieve an aspirational goal, the deadline for which is still over fifty years away. Furthermore, if EPA had considered Arizona's regional haze plan as a whole, as Congress intended, it would have realized that Arizona's plan still makes "reasonable progress" toward that 2064 goal. *See* Massey Decl., ¶¶ 39-40. In addition, the harm associated with delaying the FIP is only theoretical because even the minimal benefits EPA expects to achieve are merely predictions made using computer models relying on conservative estimates and worst-case assumptions. Massey Decl., ¶ 30(b).

Finally, unlike the concrete harm associated with the massive expenditures that EPA's plan would require, the harm associated with a delay in EPA's plan is merely aesthetic in nature because it is designed only to address visibility degradation, not health concerns. Arizona is not arguing that aesthetic values are unimportant—our national parks are worth protecting, and Arizona values its national parks greatly. However, as Congress directed, the States must consider the costs and benefits of regulation. Arizona has determined that the cost EPA would impose is not justified by the imperceptible benefits its plan would provide.

D. The Public Interest Warrants Issuing a Stay

The public interest demands that the Court resolve this dispute over state authority before the Arizona's electric utilities and their customers are forced to incur significant unrecoverable expenditures. The Clean Air Act does not demand visibility improvement at any cost; and money is not unlimited. The hundreds of millions EPA demands that Arizona's consumers expend on imperceptible visibility improvement could be spent instead on the necessities of life. Arizona has adopted a plan that significantly reduces visibility-impairing pollutants at a cost that the State believes is reasonable under the circumstances. Massey Decl., ¶¶ 38-39. Arizona should be entitled to a hearing before its utilities are forced to commit to EPA's plan.

CONCLUSION

For the foregoing reasons, the Court should stay the effective date of EPA's Final Rule pending the resolution of Arizona's petition for review. Because EPA's FIP establishes a date-certain compliance deadline of December 5, 2017, Arizona requests that the Court specify in its stay order that that deadline will be extended for the duration of the time the stay is in effect. Simply staying the effectiveness of the rule, without extending the December 5, 2017, deadline, would deny the State meaningful relief, since the December 5, 2017, deadline would continue to draw nearer while the case was adjudicated on the merits.

Dated: March 20, 2013

Respectfully submitted,

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TABLE OF EXHIBITS

Exhibit A Declaration of Eric C. Massey ("Massey Decl.").

Exhibit B Arizona Regional Haze, Technical Support Document, Page 13.

Exhibit C Declaration of J. Brent Gifford of the Cholla Power Plant ("Gifford Decl.").

Exhibit D Declaration of James M. Pratt of the Coronado Generating Station ("Pratt Decl.").

Exhibit E Arizona State Implementation Plan ("SIP"), Regional Haze Under Section 308 of the Federal Regional Haze Rule, Jan. 2011.

Exhibit F EPA Air Pollution Control Cost Manual, 6th Ed., Jan. 2002.

Exhibit G EPA Response Brief, *Nat'l Parks Conservation Ass'n v. EPA*, No. 1:11-cv-1548-ABJ (brief filed Feb. 19, 2013).

CERTIFICATE OF SERVICE

I hereby certify that I electronically filed the foregoing with the Clerk of the Court for the United States Court of Appeals for the Ninth Circuit by using the appellate CM/ECF system on March 20, 2013.

Participants in the case who are registered CM/ECF users will be served by the appellate CM/ECF system.

I further certify that some of the participants in the case are not registered CM/ECF users. I have mailed the foregoing document by First-Class Mail, postage prepaid, or have dispatched it to a third party commercial carrier for delivery within 3 calendar days to the following non-CM/ECF participants:

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Exhibit A

Declaration of Eric C. Massey ("Massey Decl.").

**DECLARATION OF ERIC C. MASSEY
IN SUPPORT OF STATE OF ARIZONA MOTION FOR STAY
OF REGIONAL HAZE FEDERAL IMPLEMENTATION PLAN**

STATE OF ARIZONA
COUNTY OF MARICOPA

Eric C. Massey Declares:

- I am the Director of the Air Quality Division for the Arizona Department of Environmental Quality (ADEQ) and has served in this capacity since July 25, 2010; and

- My duties include overseeing the State of Arizona's ambient air quality monitoring network, pollution forecasts, compliance and enforcement, industrial permitting, the state's vehicle emissions inspections program, and the development of air quality plans and rules; and

- I hold a Bachelor of Science degree in Chemical Engineering from Arizona State University, has served in the Air Quality Division at ADEQ for almost 14 years in a number of positions, including a staff level permit engineer, a permit unit supervisor, and manager of both the Air Quality Permitting and Compliance Programs; and Acting Deputy Director; and

- I am authorized to make this Declaration on behalf of the State of Arizona; and

- The statements below are, to the best of my knowledge, a true and accurate statement of the facts and my opinions.

1. Arizona's leadership in addressing regional haze is without parallel. Arizona's Governor chaired the Grand Canyon Visibility Transport Commission established by Congress in 42 U.S.C. § 7492 to tackle regional haze at the Grand Canyon in Arizona. Under Arizona's leadership, the Commission agreed to expand its efforts to address regional haze at 15 other national parks and wilderness areas on the Colorado Plateau and to enlist the participation of the governors of seven additional states and leaders of four Indian tribes covering an overall visibility transport region of nine states and 211 tribal lands. Arizona expended significant political and administrative efforts to complete the work of the Commission, which included a four-year assessment of available scientific and technical data relating to visibility impairment and development of a report recommending measures to remedy those impacts. The work of the Commission served as a model for addressing regional haze across the country, and the cooperation among the entities involved was unprecedented. After the Commission's report was complete, Arizona continued, and continues to this day, active participate in the Commission's successor entity, the Western Regional Air Partnership (WRAP). Arizona was also instrumental in the development of the WRAP Annex report in 2000 that formed the backbone for many state's regional haze plans under Section 309 of EPA's regional haze regulations. 40 C.F.R. § 51.309. A complete history of Arizona's

efforts to address regional haze, and EPA's actions in response, is provided in the statements below.

2. EPA first issued regulations addressing visibility impairment from regional haze in 1999. 40 C.F.R. § 51.308. EPA's "Section 308" regulations applied to all states and required them to adopt state plans under which they would make "reasonable progress" toward the long-term goal of eliminating manmade impairment of visibility at Class I areas (national parks and wilderness areas) by 2064. 40 C.F.R. § 51.308(d). Among other things, the state plans were required to determine whether certain large industrial facilities built between 1962 and 1977 caused or contributed to visibility degradation at Class I areas. For any such facilities, the states were required to determine the "best available retrofit technology," or "BART," that these facilities would have to adopt to reduce visibility-impairing emissions. In determining BART, states were required to balance the following five factors: "[1] the costs of compliance, [2] the energy and nonair quality environmental impacts of compliance, [3] any existing pollution control technology in use at the source, [4] the remaining useful life of the source, and [5] the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology." 42 U.S.C. §§ 7491(b), 7491(g)(2).

3. EPA's regulations also gave certain western states the opportunity to submit alternative "Section 309" plans. 40 C.F.R. § 51.309. This alternative was available for states whose emissions affect visibility conditions at the twelve Class I areas on the Colorado Plateau in the Rocky Mountain west. State Section 309 plans would not have to make BART determinations on a facility-by-facility basis but instead states could work with each other and EPA to develop a regional plan for reducing emissions to the extent that plan achieved greater emissions reductions than facility-specific BART. Arizona has been a leading proponent of addressing western regional haze issues through regional interstate cooperation and welcomed the opportunity to work with EPA and other states under EPA's Section 309 regulations.

4. On May 24, 2002, the U.S. Court of Appeals for the D.C. Circuit issued its decision in *American Corn Growers v. EPA*, 291 F.3d 1 (D.C. Cir. 2002), vacating EPA's Section 308 regional haze regulations, including the provisions regarding the determination of Best Available Retrofit Technology (BART) for certain types of large industrial facilities constructed between 1962 and 1977. The court held that EPA's Section 308 regulations unlawfully constrained state authority in favor of a less discretionary, more generic process that would impose more aggressive controls than states may deem warranted on a case-by-case review. *Id.* at 8-9.

5. On December 23, 2003, the State of Arizona submitted a State Implementation Plan (SIP) under Section 309 of EPA's regional haze regulations that would allow Arizona to work in concert with four other States (New Mexico, Wyoming, Utah, and Oregon) and one municipality (Albuquerque, New Mexico) to reduce visibility impairment caused by regional haze in protected areas on the Colorado Plateau. On December 30, 2004, the State of Arizona submitted a supplement to its December 2003 Section 309 Regional Haze SIP submission.

6. On June 23, 2004, and again on June 30, 2005, the State of Arizona's Section 309 Regional Haze SIP was deemed complete by operation of law under the Clean Air Act, due to EPA's failure to take any action within six months of Arizona's 2003 and 2004 Section 309 Regional Haze SIP submissions. 42 U.S.C. § 7410(k)(2). EPA has yet to take any final action on the Arizona Section 309 Regional Haze SIP.

7. On February 18, 2004, I agreed to co-chair the Stationary Sources Joint Forum of the Western Regional Air Partnership (WRAP), the regional planning organization created to address regional haze concerns in the western states and to coordinate western state actions under EPA's Section 309 regulations. I continued in the role of co-chair until the forum's events ended on September 25, 2008. As co-chair of the forum, I helped WRAP re-develop a regional program for reducing industrial emissions of sulfur dioxide. This program was developed by the WRAP's Market Trading Forum, which was co-chaired by then Arizona Air Quality Deputy Director Ira Domsky, and was known as the WRAP Annex and was submitted to and approved by EPA under its Section 309 regulations as a program western states could opt into to achieve sulfur dioxide emission reductions in lieu of imposing BART on individual facilities.

8. On February 18, 2005, the U.S. Court of Appeals for the D.C. Circuit issued its decision in *Center for Energy and Economic Development v. EPA*, 398 F.3d 653 (D.C. Cir. 2005) ("CEED"), in which it overturned EPA's adoption of the WRAP Annex into EPA's Section 309 rules. The Court ruled that EPA had unlawfully required the WRAP, in developing its Annex, to meet certain emission reduction targets that were contrary to the Court's ruling in *Corn Growers*. *Id.* at 659-60. The vacatur of the Annex essentially required WRAP to begin anew the process of developing an alternative regional haze plan for western states, although that process could not begin until EPA revised its regional haze regulations in response to the Court's decision. The fact that EPA's regional haze regulations had twice been overturned in court, first in the *Corn Growers* case and then in the *CEED* case, made it very difficult for western states to move quickly to develop Section 309 plans.

9. On July 6, 2005, EPA re-promulgated its Section 308 regional haze regulations in response to *Corn Growers v. EPA*. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, 70 Fed. Reg. 39,104 (July 6, 2005). EPA required that states submit new visibility plans to EPA by December 17, 2007. *See* 40 C.F.R. § 51.308(b). This requirement applied both to Section 308 and Section 309 plans, even though EPA had not yet revised its Section 309 regulations in response to the *CEED* decision.

10. On June 9, 2006, the State of Arizona requested modeling assistance from the WRAP to determine whether or not the state's BART-eligible sources contribute significantly to visibility impairment at Class I areas in Arizona and adjacent states and to determine whether or not BART emission controls will result in improvements in visibility.

11. On October 13, 2006, EPA re-promulgated its Section 309 regulations in response to *CEED v. EPA*. Regional Haze Regulations; Revisions to Provisions Governing Alternative to Source-Specific Best Available Retrofit Technology (BART) Determinations, 71 Fed. Reg.

60,612 (Oct. 13, 2006). The WRAP could now finally begin re-development of the alternative to BART programs for western states, although the timeline EPA allowed—from the October 13, 2006 date of the new rule to the December 17, 2007 due date for new state plans—was woefully insufficient to allow the WRAP to conduct the complex modeling analyses, and interstate coordination necessary to promulgate a new program.

12. On May 25, 2007, the WRAP Modeling Center provided a summary of BART modeling for those sources identified by the State of Arizona as BART-eligible.

13. On July 13, 2007, the State of Arizona sent letters to Arizona sources identifying them as "potentially-subject-to-BART." The letters requested that the sources provide the State with information and analysis to allow the State to determine whether BART, in fact, was applicable and what controls might be required. In January and February 2008, several individual facilities submitted BART analysis to the State of Arizona.

    a. In January 2008, the Cholla Generating Station operated by Arizona Public Service Company (APS) submitted its BART analysis.

    b. On February 7, 2008, the Apache Generating Station operated by the Arizona Electric Power Cooperative (AEPCO) submitted its BART analysis.

    c. On February 8, 2008, the Coronado Generating Station operated by the Salt River Project (SRP) submitted its BART analysis.

14. On December 14, 2008, after discussions with EPA, the State of Arizona sent to EPA additional copies of its 2003 and 2004 Section 309 Regional Haze SIP submissions. This submission was not a new SIP. It was sent to EPA without any revisions from the previous submissions; it was not adopted with any additional public participation process, as would have been required for adoption of a new SIP; and it was submitted without waiver of the status of the Section 309 Regional Haze SIP as "deemed complete by operation of law" under the Clean Air Act.

15. On January 15, 2009, EPA made a "Finding of Failure to Submit" ("Finding") that thirty-two states failed to submit any regional haze SIP. Finding of Failure to Submit State Implementation Plans Required by the 1999 Regional Haze Rule, 74 Fed. Reg. 2,392 (Jan. 15, 2009). EPA also found that five additional states, including Arizona, had failed to submit complete regional haze SIPs, *id.* at 2,393, even though Arizona's SIP had already been deemed complete by operation of law under the Clean Air Act, 42 U.S.C. 7410(k)(1). EPA indicated that it planned to take final action on these SIPs, including imposing FIPs if it found deficiencies in a SIP, for all thirty-seven states addressed in its Finding before January 15, 2011.

16. Between January 15, 2009, and May 13, 2010, the State of Arizona worked with EPA Regions 6, 8, and 9, as well as the States of New Mexico, Wyoming, and Utah, to develop revisions to their respective Section 309 regional haze SIPs in response to EPA's Finding. Numerous complicated issues arose regarding the analysis necessary to demonstrate, in

accordance with EPA's revised Section 309 regional haze regulations, that the alternative program would result in greater visibility improvements than BART. Additional questions arose regarding the continued viability of the program in light of the threatened withdrawal from the program of one or more western states.

17. On May 5, 2009, the State of Arizona requested additional information from AEPCO, APS, and SRP regarding their respective BART analyses.

    a. On June 18, 2009, APS submitted additional information regarding its BART analysis.

    b. On June 25, 2009, APS submitted additional information regarding its BART analysis.

    c. On June 25, 2009, SRP submitted additional information regarding its BART analysis.

    d. On July 8, 2009, AEPCO submitted additional information regarding its BART analysis.

    e. On November 4, 2010, APS submitted amended information to the State of Arizona regarding is BART analysis.

18. On May 13, 2010, the State of Arizona determined that continuing to address regional haze under Section 309 was no longer a feasible strategy. Arizona's decision was the result of the unwillingness of EPA Regions 6, 8 and 9 to agree on an emissions cap with the four remaining states (Arizona, New Mexico, Utah and Wyoming). These negotiations had continued for some time, but it wasn't until mid-2010 that Arizona realized that an agreement with EPA could not be struck and that an alternative approach was required. As a result, Arizona began developing a regional haze SIP under Section 308 of the EPA's regional haze regulations.

19. On February 28, 2011, the State of Arizona submitted a new Section 308 Regional Haze SIP to EPA Region 9. That Section 308 Regional Haze SIP provided BART determinations for the Apache, Cholla, and Coronado Generating Stations. Those BART determinations considered the five factors required by the Clean Air Act, including the costs of various pollution control options and the potential visibility improvements those controls may be expected to achieve. Specifically, Arizona examined the expected cost of both combustion control technologies and Selective Catalytic Reduction (SCR) systems for nitrogen oxides (NO_x), based on actual vendor estimates prepared for each individual facility and other available information. Arizona also examined the visibility impacts at all Class I areas within 300 km of each facility subject to BART. For instance, Arizona evaluated the visibility improvements that BART controls would create at the 13 Class I areas within 300 km of the Cholla Generating Station and the 17 Class I areas within 300 km of the Coronado Generating Station. Similarly, Arizona evaluated visibility impacts at the 9 Class I areas within 300 km of the Apache Generating Station. Arizona Section 308 SIP, App. D, Sections X, XI, and XIV. Arizona determined that SCR technology would be significantly more expensive but would only provide a visibility improvement of less than 0.5 deciviews. Arizona Section 308 SIP, App. D., at 65, 77-78, 112. Because this change would be imperceptible to the naked eye, *see* 77 Fed. Reg. 42,834, 42,840 (July 20, 2012) (a one-

deciview impact is considered perceptible to the naked eye), Arizona determined that combustion controls are BART for the Apache, Cholla, and Coronado Generating Stations.

20. After determining that combustion controls are BART for its electric utilities, Arizona established NO_x emission limits for these facilities reflecting the emission-reduction capabilities of such controls. As shown in the following table, Arizona's NO_x BART emission limits are consistent with the limits EPA adopted in its BART Guidelines as rebuttable "presumptive" limits that states should adopt for NO_x emissions from electric generating units. 40 C.F.R. Part 51 Appendix Y, Table 1. (*Note: for the facilities burning multiple types of coal, all potentially applicable, presumptive BART limits are provided*):

Table 1: Comparison of Arizona NO_x BART Determinations with EPA Presumptive NO_x BART Limits

Facility	Unit	Arizona NO_x BART (lb/mmBtu)	EPA "Presumptive" NO_x BART Limit (lb/mmBtu)
AEPCO Apache Generating Station	Unit 2	0.31	bituminous: 0.32 subbituminous: 0.23
	Unit 3	0.31	
APS & Pacificorp Cholla Generating Station	Unit 2	0.22	bituminous: 0.28 subbituminous: 0.15
	Unit 3	0.22	
	Unit 4	0.22	
SRP Coronado Generating Station	Unit 1	0.32	bituminous: 0.32
	Unit 2	0.32	

21. On August 28, 2011, Arizona's new Section 308 regional haze SIP was deemed complete by operation of law under the Clean Air Act due to EPA's failure to take any action. *See* 42 U.S.C. § 7410(k)(1).

22. On August 29, 2011, multiple parties, including the Sierra Club and the Grand Canyon Trust ("Plaintiffs"), filed a complaint in the U.S. District Court for the District of Columbia ("D.C. District Court") for declaratory and injunctive relief, seeking to compel EPA to perform an allegedly nondiscretionary duty by either approving regional haze SIPs or promulgating a Federal Implementation Plan (FIP) for dozens of states, including Arizona.

23. On November 9, 2011, EPA announced its intention to enter into a Consent Decree with the Plaintiffs. The Consent Decree included a court-ordered schedule to review and act on more than 40 state regional haze plans, including Arizona's, over the course of a little more than one year. The public was provided only 30 days to comment on the contents of the proposed Consent Decree.

24. On December 23, 2011, Arizona filed a motion to intervene as a defendant in EPA's proposed Consent Decree. The D.C. District Court granted the motion in January 2012.

25. On March 23, 2012, EPA and the Plaintiffs filed a motion to approve the Consent Decree. Arizona opposed the motion, arguing that the Consent Decree could not require EPA to impose a regional haze FIP on Arizona because EPA had not yet completed any of the statutory prerequisites for its FIP authority. Among other things, Arizona was specifically concerned that EPA had not previously found deficiencies in Arizona's Section 308 SIP and would use the Consent Decree to impose a Section 308 FIP on Arizona without giving the State any opportunity to correct deficiencies EPA may allege. The Court, however, approved the Consent Decree on March 30, 2012. *Nat'l Parks Conversation Ass'n v. EPA*, D.D.C. No. 1:11-cv-1548-ABJ (Consent Decree approved March 30, 2012).

26. On May 29, 2012, EPA and the Plaintiffs administratively extended the deadlines for action on the portion of Arizona's Section 308 SIP that did not address the BART determinations for the Apache, Cholla, and Coronado facilities. This extension specifically allowed EPA to bifurcate its action on the portions of the SIP addressing those facilities and the balance of the Section 308 SIP. Third Stipulation to Amend Consent Decree, 1:11-cv-01548 (May 29, 2012),

27. On June 27, 2012, Arizona filed a Notice of Appeal of the District Court's decision to enter the Consent Decree on March 30, 2012 to the U.S. Circuit Court of Appeals for the D.C. Circuit.

28. On July 2, 2012, the D.C. District Court upheld Consent Decree revisions that EPA and the Plaintiffs had agreed to, setting deadlines for proposed action on the BART determinations for the three electric generating facilities by July 2, 2012 and on the balance of the Section 308 Regional Haze SIP by December 8, 2012. Final action for the BART determinations was required on or before November 15, 2012, and final action for the balance of the SIP was required on or before July 15, 2013.

29. On July 20, 2012, EPA published a notice of proposed rulemaking to partially approve and partially disapprove Arizona's 308 Regional Haze SIP. Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans; Proposed Rule, 77 Fed. Reg. 42,834 (July 20, 2012). As Arizona feared, EPA simultaneously proposed to impose a FIP for the portions of Arizona's SIP it proposed to disapprove and did not propose to provide Arizona with any time to correct the EPA-identified SIP deficiencies before EPA imposed the FIP. *Id.* at 42,836.

30. In its notice, *see* 77 Fed. Reg. 42,834, EPA proposed to disapprove the NO_x BART determinations for the Apache, Cholla, and Coronado Generating Stations for several reasons.

    a. First, EPA claimed that Arizona's cost calculations were incorrect because they accounted for costs that utility companies incur as part of any significant capital expenditures, including Allowance for Funds Used During Construction (AFUDC), owner's cost, and surcharges. See EPA Technical Support Document (Exh. B to Arizona's motion) at 15, 20, 27; 77 Fed. Reg. at 72,516. The Clean Air Act does not

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prohibit states from considering these costs in their BART analyses. Likewise, such costs are not mentioned in EPA's generic Control Cost Manual (one of several potential sources of information identified in EPA's BART Guidelines). However, those costs are real costs – financing costs, internal company costs, and other charges and expenditures – that will be borne by the utilities, and eventually all electric consumers they serve, to install the additional control equipment required. To ensure an accurate and realistic estimate of the costs associated with the various BART options, Arizona incorporated AFUDC, owner's cost, and surcharges into its cost-effectiveness analysis. Moreover, Arizona's cost calculations were consistent with the Manual. First, it does not directly cover utilities. Manual at 1-3 ("[T]his Manual does not directly address the controls needed to control air pollution at electrical generating units . . . ."). Second, the Manual explains that it is best suited for regulatory development using generic information, not for site-specific, cost-effectiveness determinations for individual facilities. *Id.* at 1-4 ("This type of estimate is well suited to estimating control system costs intended for use in regulatory development because they do not require detailed site-specific information . . . ."). Finally, the Manual recognizes that customization is both expected and necessary to develop more accurate assessments. *See id.* ("The Manual and its supporting programs are also well suited to customization by industrial sources . . . . [S]uch customized analyses are by definition of greater accuracy than the generic study level analysis of the regulator . . . ±30%."). (Relevant excerpts from the Manual are attached to Arizona's motion for stay at Exh. F.)

b. Second, EPA claimed that Arizona's visibility analysis was incorrect because it failed to account for "cumulative" visibility improvements at all Class I areas. 77 Fed. Reg. at 72,519. Neither the Clean Air Act nor EPA's regulations require a "cumulative visibility" analysis. Instead, as recommended in EPA's Guidelines, Arizona focused on the single most impacted Class I area for each facility, since combining improvements across multiple Class I areas may give a false impression of more significant improvements than any visitor to any Class I area would actually experience. Arizona also considers EPA's cumulative visibility approach to be inappropriate in light of the highly conservative nature of the computer modeling results that EPA would add together. EPA's visibility analysis relies on the 98th percentile results – essentially the near-maximum visibility impacts (that is, the visibility impacts on the 2% highest impact days modeled) – predicted by the "CALPUFF" computer model for each individual Class I area, based on worst-case emission rate assumptions.

31. The FIP EPA proposed would require the Apache, Cholla, and Coronado Generating Stations to install Selective Catalytic Reduction equipment. EPA also proposed to establish emission limits at a fraction of, and far more stringent than, the "presumptive" BART limits set forth in EPA's BART Guidelines. The emission limit that EPA proposed for most of the units was 0.050 pounds per million British thermal units (lb/mmBtu), even though that limit has never been achieved using the compliance demonstration requirements imposed in the FIP. BART of course applies to existing sources, but even *new* units have never achieved this standard. The State of Arizona commented as follows:

> ADEQ strongly opposes the use of 0.050 pounds per million BTU per hour emission limit on NO_x since achieving this level as part of a retrofit project has never been demonstrated to be technically feasible. … At that time, only two *new* facilities were subject to a 0.05 lbs/MMBtu limit. It is ADEQ's current understanding that one of those two facilities was never built and that the second facility, San Juan, is litigating due to the infeasibility of meeting its less stringent limit of 0.05 lbs/MMBtu.

32. On November 15, 2012, EPA finalized its proposal to simultaneously disapprove the portion of Arizona's Regional Haze SIP addressing BART for three electric generating facilities and impose a FIP on the State with respect to those facilities, without allowing any time for Arizona to revise its Section 308 Regional Haze SIP in response to EPA's final action. EPA published its final partial disapproval and FIP for Arizona in the Federal Register on December 5, 2012. Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans; Final Rule, 77 Fed. Reg. 72,512 (Dec. 5, 2012).

33. As the owners of the Apache, Cholla, and Coronado facilities have stated, the controls required by EPA's FIP will cost Arizona's electric consumers hundreds of millions of dollars. As noted above, however, Arizona's analysis shows that the EPA plan yields no perceptible visibility improvement as compared with Arizona's plan. Arizona Section 308 SIP, App. D, Sections X, XI, and XIV.

34. On December 21, 2012, EPA published a proposed partial approval and partial disapproval for the remainder of Arizona's Section 308 Regional Haze SIP. Partial Approval and Disapproval of Air Quality Implementation Plans; Arizona; Regional Haze, Proposed Rule, 77 Fed. Reg. 75,704 (Dec. 21, 2012). On March 6, 2013, ADEQ provided EPA with comments on its proposed partial approval and partial disapproval for the remainder of Arizona's Section 308 Regional Haze SIP.

35. On January 31, 2013, the State of Arizona petitioned the U.S. Court of Appeals for the Ninth Circuit for review of EPA's final partial disapproval of Arizona's Section 308 Regional Haze SIP and EPA's partial Regional Haze FIP for three electric generating units.

36. On March 6, 2013, Arizona requested that EPA stay its action disapproving Arizona's plan and imposing a FIP. As of this writing, EPA has not yet responded.

37. On February 5, 2013, after nearly a decade of inaction, EPA finally published a proposal to partially approve and partially disapprove Arizona's 2003 Section 309 Regional Haze SIP. Partial Disapproval of State Implementation Plan; Arizona; Regional Haze Requirements, Proposed Rule, 78 Fed. Reg. 8,083 (Feb. 5, 2013). On March 7, 2013, ADEQ provided EPA with comments on its proposed partial approval and partial disapproval of Arizona's Section 309 Regional Haze SIP.

38. In sum, Arizona's Section 308 plan, considered as a whole, makes strong progress towards improving visibility conditions. Just regarding NO_x emissions from the facilities in question, Arizona's plan would nearly halve those emissions, requiring a reduction of 18,357 tons per

year at a cost of millions of dollars per year. EPA's plan would require a reduction of another 16,705 tons per year but at a capital cost of hundreds of millions of dollars. Under Arizona's plan, the cost of NO_x reductions would be \$237-\$445 per ton reduced, whereas the cost of the additional NO_x reductions under EPA's plan would be dramatically higher, \$2405-\$3331 per ton reduced. Since EPA's plan overall would not make perceptible visibility improvements as compared with Arizona's plan, Arizona determined that it could not justify imposing these types of costs on Arizona's electric consumers.

39. I would also like to point out that Arizona has been successful through all of its long-standing efforts to improve visibility in the State's Class I areas and will continue that progress under its Section 308 SIP. EPA's regional haze regulations provide for states to make reasonable progress towards EPA's goal of achieving natural visibility conditions by 2064. Achievement of EPA's goal is not mandatory, and EPA encourages but does not require that states make steady and continuous progress toward that goal between now and 2064. 42 C.F.R. § 308(d)(1). According to Arizona's latest analysis, if the monitored overall visibility trends at each of the Class I areas within the State continue, then Arizona will be on a "glide path" to achieve that goal for all but two Class I areas. The primary cause of visibility degradation in Arizona appear to be related to wildfires. Wildfires in the West are natural and uncontrollable sources of visibility impairment. If the baseline period is simply adjusted to include the 2005 wildfire year, and the monitoring results from 2010 are included in the analysis, every site within Arizona is projected to exceed the uniform rate of progress toward EPA's goal of natural conditions. This progress is projected to occur just with controls already in place.

I, Eric C. Massey, declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct

Dated this 20th day of March, 2013.

Eric C. Massey
Director, Air Quality Division
Arizona Department of Environmental Quality

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Exhibit B

Arizona Regional Haze
Technical Support Document, July 2012

Arizona Regional Haze Technical Support Document

Prepared and Reviewed by:
Margaret Alkon, Scott Bohning, Eugene Chen, Francisco Dóñez, Steve Frey,
Colleen McKaughan, Thomas Webb, Charlotte Withey

July 2012

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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. AEPCO Apache Generating Station Unit 1

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

(1) 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 conservative simplifying assumption, baseline No. 2 fuel oil NO_x emissions were assumed to be equal to natural gas

BART implementation date of 2013.[17] 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.[18]

(2) 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}

(1) 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.[19] 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

[17] See Docket Item B-02. Page 2-1 of AEPCO Apache 1 BART Analysis
[18] See Docket Item B-01. Emission rate as specified in Table 10.2, Appendix D (Technical Support Document) of Arizona Regional Haze SIP
[19] See Docket Item B-02, Page 2-1 of AEPCO Apache 1 BART Analysis.

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.[28] 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.

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 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…"[29]

(2) 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 Tables 20 and 21 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

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[28] Arizona SIP submittal, "Appendix D: Arizona BART – Supplemental Information", p.65.
[29] Docket Item B-01, Arizona Regional Haze SIP, Appendix D, Page 65.

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 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."[46] 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."[47]

(2) 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}

(1) 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.[48] 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

[46] Docket Item B-01, Arizona Regional Haze SIP, Appendix D, Page 79.
[47] Id.
[48] 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.

Exhibit C

Declaration of J. Brent Gifford
of the Cholla Power Plant ("Gifford Decl.").

ENVIRONMENTAL PROTECTION AGENCY
40 CFR Part 52
[EPA-R09-OAR-2012-0021; FRL-9754-3]
Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans; Final Rule

DECLARATION OF J. BRENT GIFFORD
IN SUPPORT OF PETITION OF ARIZONA PUBLIC SERVICE COMPANY
FOR STAY OF EFFECTIVE DATE OF FEDERAL IMPLEMENTATION PLAN

I, J. Brent Gifford, having first been duly sworn upon my oath, declare and state as follows:

1. My name is J. Brent Gifford and I am the Acting Director Design Engineering and Fossil Projects for Arizona Public Service Company ("APS"). My business address is 400 North Fifth Street, Phoenix, Arizona 85004. I hold Bachelor and Master degrees from Brigham Young University. I have worked in the public utility industry since 1986. My statement of qualifications is attached as Gifford Exhibit 1. I am over the age of 18 and I am competent to testify concerning the matters in this declaration.
2. This declaration is submitted in support of APS's petition for the temporary stay of the effective date of the *Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans; Final Rule* in EPA Docket No. EPA-R09-OAR-2012-0021 (hereinafter "Final Rule"). The Final Rule includes a determination of best available retrofit technology ("BART") for the Cholla Power Plant ("Cholla"), which, among other things, will require the installation of selective catalytic reduction ("SCR") control technology on all three BART-eligible units (the "SCR Project") to control NO_x emissions.
3. APS anticipates the permit application preparation for the SCR Project will take approximately six to nine months. APS estimates that it will have to submit an application

for modification to the operating permit no later than July 2013. The estimated costs to obtain the required permit will be approximately $100,000.

4. The Final Rule requires Cholla to complete installation and commence operation of the SCR Project on Cholla Units 2, 3, and 4 by December 5, 2017, which is within five years after the Final Rule effective date. The installation of SCR control technology in this short time frame will be a massive construction project requiring extensive planning and logistical coordination. APS's recent experience with the construction of major environmental upgrades at Cholla confirms that advance planning and coordination is essential for a timely and successful project.

5. APS hired CH2MHill, a preeminent design, engineering, and consulting firm, to provide the SCR Project costs as part of a study in order for APS to understand its NO_x reduction options. In the study issued in 2008, CH2MHill provided a preliminary cost estimate of $248 million (2007 dollars, excluding Allowance for Funds Used During Construction) for the SCR Project with an increase in annual operation and maintenance costs of $5.6 million (2007 dollars). I have reviewed the CH2MHill cost estimate and the necessary phases of the design and construction of the SCR Project against the EPA five-year compliance deadline and prepared an estimate of the timing of the likely cost, as it appears at this time, to be incurred through the life of the project. A copy of my estimate of the timing of the approximate costs to be incurred for the SCR Project is attached as Gifford Exhibit 2.

6. In the absence of a temporary stay of the effective date of the Final Rule, in order to meet the five-year deadline for installation of SCR control technology, APS will need to initiate the permitting of the SCR Project and the contracting process for engineering and construction of the SCR Project. In order to be prudent, and to ensure reasonable engineering and

construction costs, APS intends to place the SCR Project out for bid. APS's current construction timeline calls for a request for proposal to be issued to prospective bidders in March 2014 with responses back in July 2014. A contract for engineering, procurement, and construction for the SCR Project should be in place by October 2014 with the final unit's in-service date prior to the compliance date.

7. Site preparation for construction of the SCR Project will need to begin by July 2015. The upfront fee for engineering, procurement, and construction will need to be paid by October 2014, and regular payments made after that to cover on-going costs. Actual erection of SCR Project structures will need to commence by September 2015 in order to meet EPA's five-year deadline.

8. APS (sole owner of Units 2 and 3) and PacifiCorp (sole owner of Unit 4) will incur significant costs for the SCR Project during the pendency of APS's request for reconsideration before EPA, and if necessary, APS's appeal of the Final Rule before the United States Court of Appeals for the Ninth Circuit. According to my estimate, by December 2014, the engineering and construction expenses for the SCR Project will total approximately $10 million. Of that amount, APS's share is estimated to be $4.3 million and PacifiCorp's share $5.7 million. Total estimated SCR Project costs through December 2014 are anticipated to be approximately $13 million with APS's share estimated to be $5.5 million and PacifiCorp's share estimated to be $7.5 million. (Because Unit 4 will be the first unit on which SCR control technology is installed, a larger portion of the early years' costs will be borne by PacifiCorp. The final amounts expected to be paid by APS and PacifiCorp are $187 million and $125 million, respectively.) These estimated costs are based on preliminary design specifications.

9. The Final Rule imposes a NO_x BART emission limit of 0.055 lb/mmBtu determined as an average of the three units, based on a rolling 30-boiler-operating-day average, based on installation and operation of SCR control technology. Averaging NO_x emissions between the three Cholla BART units involves significant problems. If a unit has trouble starting and has four or five starts in a 30-operating-day period, which Cholla has experienced in recent years, it could cause the "bubbled" units to exceed the 0.055 lb/mmBtu NO_x limit. NO_x emissions during start-up, ramping, and shut-down will be higher than at normal operating conditions. If this higher-emitting unit then has to shut down, the 30-day period including these higher NO_x emissions would continue to be averaged with the other two units, potentially resulting in a string of exceedances. This is a fundamental problem with the Final Rule's novel 30-boiler-operating-day-rolling-average method of compliance and the requirement that start-ups be included in the average.
10. The Final Rule also requires APS to achieve and maintain a 30-day rolling average sulfur dioxide ("SO_2") removal efficiency of 95 percent by December 5, 2013 on Units 3 and 4 and by April 1, 2016 on Unit 2. The scrubbers at Cholla were designed to meet the BART limit of 0.15 lb/mmBtu SO_2 established under Arizona's regional haze SIP. They were not designed to meet 95 percent SO_2 percent removal. To determine whether this removal efficiency could be achieved, APS would need to conduct extensive testing, engineering, and design. To the extent it is determined to be feasible, the necessary modifications would then have to be made. Moreover, in order to comply with a percent removal requirement, Cholla Units 3 and 4 would require inlet SO_2 continuous emissions monitors ("CEMS"). There is insufficient time to engineer, procure, and install inlet SO_2 CEMS prior to the Final Rule compliance date.

11. APS and PacifiCorp will incur significant costs for inlet SO_2 continuous emissions monitors ("CEMS") during the pendency of APS's request for reconsideration before the EPA, and if necessary, APS's appeal of the Final Rule before the United States Court of Appeals for the Ninth Circuit. According to my estimate, by March 2013—the latest possible date that the vendor will be able to deliver the equipment in time to meet the Final Rule compliance date—the expenses associated with the design, procurement, installation, and certification of the inlet SO_2 CEMS for Cholla Units 3 and 4 will total approximately $500,000.

Date: February 4, 2013

Brent Gifford

J. Brent Gifford

Exhibit D

Declaration of James M. Pratt
of the Coronado Generating Station ("Pratt Decl.").

DECLARATION OF JAMES M. PRATT IN SUPPORT OF PETITION OF SALT RIVER PROJECT AGRICULTURAL IMPROVEMENT AND POWER DISTRICT FOR PARTIAL RECONSIDERATION OF FINAL RULE AND STAY OF EFFECTIVE DATE OF FEDERAL IMPLEMENTATION PLAN

I, James M. Pratt, having first been duly sworn upon my oath, declare and state as follows:

1. My name is James M. Pratt and I am the Senior Director of Baseload Generation for Salt River Project Agricultural Improvement and Power District ("SRP"). My business address is POB002, 6504 East Thomas Road, Scottsdale, Arizona 85251-6008. I am competent to testify concerning the matters in this declaration. I received a Bachelor of Science degree in Mechanical Engineering from Montana State University in 1983. I have more than 28 years of experience in the electric utility industry. I have held a variety of management positions at SRP in engineering, maintenance and operations at several gas and coal generation facilities, as well as transmission planning.

2. In my current position with SRP, I am responsible for the operation of two coal generation facilities operated by SRP – the Coronado Generating Station ("Coronado") and the Navajo Generating Station. I also represent SRP's interests with respect to the other coal generation facilities in which SRP holds an interest but which are operated by other utilities. I also oversee engineering support for SRP's generation assets and the construction of generation-related major projects, such as emission control improvements.

3. I served as the lead technical representative for the negotiation of a consent decree entered into with EPA to resolve alleged violations of Prevention of Significant Deterioration ("PSD") requirements under the Clean Air Act at Coronado. After extensive negotiations with

EPA, a consent decree was entered by the U.S. District Court for the District of Arizona on August 12, 2008. This consent decree resolved alleged PSD violations for *both* Coronado units. *U.S. Environmental Protection Agency v. Salt River Project Agricultural Improvement and Power District*, Case 2:08-cv-014790JAT (D. Ariz. 2008) ("consent decree") (Attachment A). To comply with the consent decree, SRP has already installed low NOx burners ("LNB") with overfire air ("OFA") systems, and wet flue gas desulfurization ("WFGD") equipment on both units at Coronado, and is in the final stages of completing the installation of selective catalytic reduction ("SCR") equipment on Unit 2.

4. This declaration is submitted in support of SRP's petition for partial reconsideration of the final rule issued by the U.S. Environmental Protection Agency ("EPA" or "Agency"), titled "Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona; Regional Haze State and Federal Implementation Plans; Final Rule," 77 Fed. Reg. 72512 (December 5, 2012) ("Final Rule"), and for a temporary stay of the effective date of the federal implementation plan ("FIP") promulgated as part of the Final Rule. SRP is challenging certain elements of EPA's best available retrofit technology ("BART") determination affecting Coronado and seeks a stay of the effective date of the FIP for Coronado pending administrative reconsideration and a litigation appeal of that portion of the Final Rule.

5. SRP is a political subdivision of the State of Arizona that provides retail electric services to more than 950,000 residential, commercial, industrial, agricultural and mining customers in a 2,900 square mile area in Arizona. SRP operates or participates in 11 major power plants and numerous other generating stations, including coal, nuclear, natural gas and renewable sources, such as hydroelectric, solar, wind and geothermal.

6. SRP's load responsibility peak demand was over 7,072 megawatts ("MW") on August 24, 2011. SRP's current generation portfolio has a combined capability of approximately 7,874 net-MW. In 2012, coal-fired generation represented approximately 37 percent of SRP's total generation capability, but produced almost 59 percent of its retail energy requirements.

7. Coronado is a 773 net-MW coal-fired, steam electric generating station located near St. Johns, Arizona. Coal is provided to the plant from the Powder River Basin in Wyoming. Upon completion of the installation of additional emission controls required under the consent decree, including installation of SCR on Unit 2 by June 2014, the Coronado units will have the following emission controls in place:

> Unit 1 – LNB with OFA; WFGD System; Hot-Side Electrostatic Precipitator ("ESP")
>
> Unit 2 – SCR; LNB with OFA; WFGD System; Hot-Side ESP

8. The Final Rule mandates that SRP must attain a nitrogen oxide ("NOx") emission limit of 0.065 pounds per million British thermal units ("lb/mmBtu") for Coronado, determined as an average of Coronado Units 1 and 2, based on a rolling 30-boiler-operating-day ("BOD") average. The established emission limit is infeasible because it fails to provide an adequate compliance margin for Coronado to maintain continuous compliance.

9. In setting the plantwide average NOx emission limit in the FIP, EPA stated the Agency did not require a NOx emission limit for Coronado Unit 2 that is more stringent than 0.080 lb/mmBtu in recognition of the work already performed by SRP to meet the NOx limit established in the 2008 consent decree for the plant. 77 Fed. Reg. at 72556. Because EPA retained an effective emission limit of 0.080 lb/mmBtu on a rolling 30-BOD average for Unit 2, as a practical matter, Coronado Unit 1 must meet an effective limit of 0.050 lb/mmBtu on a

rolling 30-BOD average to maintain compliance with the plantwide NOx emission limit of 0.065 lb/mmBtu.

10. EPA acknowledged that the individual Coronado units cannot achieve a NOx emission rate of 0.050 lb/mmBtu on a rolling 30-BOD average based on the Agency's review of the analysis provided by SRP during the public comment period on the Proposed Rule. 77 Fed. Reg. at 72535. EPA further concluded that it is appropriate to provide a compliance margin for periods of startup and shutdown when establishing a rolling 30-BOD average BART emission limit. *Id.*

11. During the public comment period on EPA's Proposed Rule, Arizona Electric Power Cooperative ("AEPCO") did not submit a technical analysis regarding the achievability of a rolling 30-day average NOx BART emissions limit of 0.050 lb/mmBtu at Apache Generating Station ("Apache") Units 2 and 3. In the absence of such an analysis, EPA applied the results of the feasibility analysis conducted by SRP for the Coronado units, as the boiler design of the affected AEPCO units is almost identical to that of the affected Coronado units. After reviewing the SCR system analysis provided by SRP, EPA finalized a rolling 30-BOD average NOx BART emissions limit of 0.070 lb/mmBtu for Apache Units 2 and 3 as a "bubble" across these two units. 77 Fed. Reg. at 72535. EPA stated that the magnitude of the increase from the proposed individual unit limits of 0.050 lb/mmBtu was appropriate to accommodate emissions from startup and shutdown events, as well to provide AEPCO a sufficient measure of operational flexibility as a small entity. *Id.*

12. As EPA acknowledged, there are several important similarities between Apache Units 2 and 3 and Coronado Units 1 and 2. Specifically, all four of these units:

a. Are the same boiler type (Riley turbo);

b. Were constructed and placed into operation at approximately the same time (1979-1980);

c. Have access to, and potentially could use, a bituminous and sub-bituminous coal blend; and

d. Exhibit a greater number of startup and shutdown events than coal-fired units used more consistently as baseload generation.

77 Fed. Reg. at 72535. Despite recognizing the similarities between the Apache and Coronado units and increasing the emission limit for Apache to reflect the infeasibility of complying with a 0.050 lb/mmBtu limit on a rolling 30-BOD average, EPA failed to provide an equivalent compliance margin to accommodate startup and shutdown events for Coronado Unit 1.

13. The Final Rule does not provide an adequate margin of compliance for Coronado Unit 1. Even new, state-of-the-art facilities have not been required to show continuous compliance with a 0.050 lb/mmBtu NOx emission rate on a rolling 30-BOD average basis. *See* RMB Consulting & Research, Inc., Technical Memorandum Regarding Achievability of the Proposed FIP NOx Limit for CGS Unit 1 (September 4, 2012), at 10 (Attachment B); *see also* RMB Consulting & Research, Inc., Technical Memorandum Regarding Analysis of the Achievability of the FIP NOx Limit for San Juan Generating Station and Comparison to Other Ultra-Low NOx Units (October 21, 2011), at 10 (Attachment C).

14. In addition to failing to provide an adequate compliance margin for Coronado, EPA established in the Final Rule a new emission calculation procedure to determine compliance with the NOx emissions limit established by the FIP. Under that new procedure, compliance with the rolling 30-BOD average NOx emission limit "bubble" is calculated each calendar day, even if a unit is not in operation on that calendar day.

15. The NOx BART compliance approach set out in the Final Rule was not contemplated in the Proposed Rule. In addition, EPA has acknowledged that the use of an offline unit's preceding 30-BOD information in determining compliance with a plantwide emission limit is a novel concept in that EPA is unaware of any other permitted emission sources that use this methodology to demonstrate compliance. *See* EPA, "Questions for AZ Regional Haze FIP Conference Call" (January 22, 2013), at 3 (stating that EPA is "not aware of other permits or emission sources using the same methodology" of using an offline unit's preceding 30-day totals) (Attachment D). Accordingly, in light of this statement by EPA, and to the best of my information, this compliance methodology has never been included in any proposed air quality regulation and has never been the subject of a proper public notice and comment proceeding.

16. This averaging methodology may very likely create enforcement consequences for SRP, as outlined in the next several paragraphs.

17. NOx emissions in coal-fired boilers are at their lowest level when units return to service after outages where maintenance work has been performed on emission control equipment such as LNB or SCR. This improved performance immediately after an outage is achieved during normal operating conditions and is not material to emission performance experienced during startup, shutdown or equipment malfunctions. During these regularly-scheduled outages, furnace combustion equipment is inspected and repaired or replaced as necessary. SCR equipment also undergoes substantial maintenance with the various components of the ammonia injection system being repaired or replaced and the SCR catalysts being cleaned or replaced. NOx performance begins to degrade soon after the unit is started up, however, and continues to degrade until the next opportunity to perform extended maintenance in a planned outage.

18. Planned outages for Coronado Units 1 and 2 are scheduled to occur every three years to balance unit performance with operating and maintenance costs. This three-year cycle is consistent with standard industry practice. In addition, these planned outages typically last 3.5 to 4 weeks and are scheduled to occur during the off-peak power season to ensure adequate generation resources are available to meet demand, minimize replacement power costs and utilize the skilled labor in the region due to planned unit outages at other generating facilities.

19. As indicated above, because the Final Rule maintains an effective consent decree NOx limit for Unit 2 of 0.080 lb/mmBtu on a 30-BOD average, Coronado likely will not be able to maintain continuous compliance with the new plantwide NOx limit, as demonstrated by the following examples. These examples are not intended to be all-inclusive, or to indicate that SRP believes that 0.050 lb/mmBtu is feasible on a 30-BOD average.

> ***Example 1***: *Coronado Unit 2 is approaching the time for a planned outage to address various routine maintenance activities. Coronado Unit 1 will continue to operate while Unit 2 is in outage. This is a normal situation that will occur at least once every 3 years.*
>
> > As Coronado Unit 2 approaches its planned outage, portions of the LNB equipment, OFA equipment, and SCR equipment (including catalyst and the ammonia injection grid) will be at or near the point when substantial repair or replacement is required due to routine use. As a result, the Coronado Unit 2 30-BOD NOx average is very likely to be near the 0.080 lb/mmBtu consent decree limit prior to the next scheduled outage for performing emission control system maintenance. Because Coronado must continue to include the last calculated 30-BOD NOx average from Unit 2 in the daily plantwide average calculation during each outage period – even though, during Unit 2's planned outage, there are zero emissions from Unit 2 – Coronado Unit 1 must operate at a 30-BOD NOx average of approximately 0.050 lb/mmBtu during these periods. EPA has acknowledged this rate is not achievable on a 30-BOD basis.
> >
> > As a result, Coronado Unit 1 likely would have an insufficient margin in the plantwide 30-BOD NOx limit to allow it to continue operating if

electrical system demand requires low-load cycling or the unit is required to shut down and start up for any maintenance or operational reason during the Unit 2 planned outage. The inability of the limit to accommodate these routine events could result in exceeding the plantwide emissions limit merely because the Final Rule requires the inclusion of the 30-BOD NOx average from Unit 2, which would have zero air emissions during the outage period.

In this event, SRP would have difficulty determining the appropriate course of action, as shutting down Unit 1 would not alleviate an exceedance of the limit. In fact, such an exceedance would continue even if both units are offline and not emitting *any* NOx because compliance with the plantwide average limit is determined each calendar day with previously calculated unit-level 30-BOD averages. SRP therefore understands that the only way to alleviate the exceedance would be for SRP to perform a startup on Unit 2 and operate until such time that the plantwide 30-BOD NOx average returns to the appropriate range. It could take several days or weeks before Unit 2 could be returned to service, depending upon the scope of the Unit 2 planned outage. Unfortunately, the need to return Unit 2 to service to meet SRP's customer and system needs could cause an unavoidable exceedance of the FIP's BART emission limit.

<u>Example 2</u>: *Coronado Unit 1 is approaching a planned outage for addressing various routine maintenance activities. Coronado Unit 2 will continue to operate while Unit 1 is in outage. This is a normal situation that will also occur at least once every 3 years.*

As Coronado Unit 1 approaches its planned outage, the 30-BOD average for Unit 1 reasonably may be expected to be at or above the effective unit limit of 0.050 lb/mmBtu. Because Coronado must continue to count the 30-BOD NOx average from Unit 1, Coronado likely would need the Unit 2 SCR to achieve a 30-BOD NOx average better than 0.065 lb/mmBtu for the entire duration of the outage to ensure that sufficient margin is available for Unit 1 to return from outage. SRP does not expect that Unit 2 would be capable of achieving what would amount to a short-term permit limit nearly 20 percent lower than the design parameters when this unit is approximately two years into a three-year maintenance cycle.

It is likely that electrical system demand would require low-load cycling on Unit 2 during the Unit 1 outage. SRP specifically schedules routine planned outages during times when overall electrical system energy demands are lower. Low-load cycling could result in exceeding the plantwide emissions limit established in the FIP — despite Unit 2

> maintaining compliance with the consent decree limit – only as a result of including the last 30-BOD NOx average from Unit 1.
>
> If an exceedance occurs, shutting down Unit 2 would not immediately alleviate the exceedance due to the requirement for daily calculation of the plantwide average. If startup of Unit 1 was needed to reduce the calculated average, the exceedance would continue until SRP could complete the planned outage maintenance work and operate Unit 1 long enough to reduce the plantwide average. As mentioned in the previous example, such actions could cause an unavoidable exceedance of the FIP's BART emission limit.

Example 3: *Coronado Units 1 and 2 are both operating at baseload conditions and the plant is achieving the plantwide NOx limit of 0.065 lb/mmBtu. Unit 2 is operating at or slightly below the consent decree limit of 0.080 lb/mmBtu. Unit 1 is operating at or slightly below 0.050 lb/mmBtu to maintain compliance with the plantwide average. Unit 2 experiences an unplanned outage associated with a unit trip. (Over the past decade, each Coronado unit has experienced multiple trip events per year, in addition to controlled startups and shutdowns.)*

> In order for SRP to return Unit 2 to service, Unit 1 will be required to operate at a substantially lower emission rate to ensure sufficient margin for Unit 2 to startup without causing an exceedance. This emission rate would need to be less than 0.050 lb/mmBtu on a 30-BOD basis, which EPA has acknowledged repeatedly is not feasible. Thus, SRP may be unable to return Unit 2 to service without exceeding the limit established by the FIP.

20. In the preamble to the Final Rule, EPA indicated that the Agency expects that SRP can meet the 0.065 lb/mmBtu limit on a continuous basis by installing a low load temperature control system on Unit 2 and an SCR system including a low load temperature control system on Unit 1. 77 Fed. Reg. at 72556.

21. SRP contracted with Sargent & Lundy LLC ("S&L") to conduct an SCR feasibility analysis to determine the implications of accepting a lower emission limit for

Coronado Unit 2 as compared with the consent decree limit of 0.080 lb/mmBtu on an individual unit 30-BOD average. S&L estimated the potential impact that unit startups and shutdowns would have on a rolling 30-BOD average NOx emission rate through a modeling exercise. S&L's modeling analysis demonstrated that SRP would be out of compliance with the Unit 2 consent decree limit of 0.080 lb/mmBtu if that unit experienced more than 1 startup per 30 operating days if a low-load temperature control system was not utilized. Sargent & Lundy LLC, Salt River Project Coronado Generating Station Unit 2 SCR Review: Final Report SL-011433 (August 24, 2012) (Attachment E). SRP is installing a low-load temperature control system for Unit 2 as part of the SCR installation to provide necessary operating flexibility while maintaining compliance with the 0.080 lb/mmBtu consent decree limit. Operational flexibility is critical to SRP in supplying affordable, reliable electricity. This additional work does not enable Coronado to comply with the plantwide NOx emission limit established for Coronado in the Final Rule.

22. SRP retained S&L to perform this analysis because of the company's extensive experience in providing comprehensive consulting, engineering, design and analysis for electric power generation and power delivery for projects worldwide. In addition, SRP selected S&L based on S&L's involvement in the various engineering activities associated with the consent decree control improvements at Coronado.

23. EPA also has effectively acknowledged S&L's expertise. In creating its Base Case v.4.10 using the Integrated Planning Model, EPA retained S&L to develop cost and performance assumptions for sulfur dioxide and NOx emission controls as part of a major update to EPA's emission control technology assumptions. *See* United States Environmental Protection Agency, Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model, EPA

#430R10010 (August 2010). Base cases, like EPA Base Case v.4.10, provide a projection of electricity sector activity that takes into account federal and state air emission laws and regulations. As demonstrated by its retention by EPA to contribute to this EPA project, the Agency has recognized S&L for its technical expertise related to NOx emission control technology performance and cost.

24. EPA acknowledges that the BART NOx emission limit for Coronado will require SRP to install an SCR system on Unit 1. SRP currently estimates the total cost for this technology to be at least $105 million. To meet the FIP compliance deadline in the Final Rule, SRP will be required to immediately expend significant sums for permitting, analysis of compliance feasibility and options and preliminary planning and design work. Such efforts will require both significant internal staff commitment and the retention of outside experts, at a projected cost of approximately $5,850,000 within the next 12-24 months. To meet the FIP compliance date established in the Final Rule, SRP will need to perform the following work: (1) 2013 – complete upfront engineering and modeling ; (2) 2014 – complete the permit application process and begin ordering major equipment to ensure equipment receipt onsite by late 2016; and (3) 2015-2017 – complete construction and tie-in work. If the Final Rule stands, SRP currently expects to incur at least the following estimated annual expenditures to complete installation of SCR on Unit 1 by the deadline established in the Final Rule:

Table 1: Estimated Approximate Annual Cash Flow for Installation of SCR on Coronado Unit 1

Calendar Year	Estimated Expenditures (Approximate)
2013	$ 850,000
2014	$ 5,000,000
2015	$ 20,000,000
2016	$ 55,500,000
2017	$ 23,650,000

This cash flow will be required to complete installation of SCR on Coronado Unit 1 by the deadline set forth in the Final Rule.

Date: February 4, 2013

James M. Pratt

Exhibit E

Arizona State Implementation Plan ("SIP"), Regional Haze
Under Section 308 of the Federal Regional Haze Rule, Jan. 2011.

ADEQ
Arizona Department
of Environmental Quality

Arizona State Implementation Plan

Regional Haze Under Section 308 Of the Federal Regional Haze Rule

Air Quality Division
January 2011

reasonably installed and operated on the source type that is under review. If a technology is considered to be both available and applicable, a state should consider the technology to be technically feasible.

If a technology is determined to be technically infeasible, then the state should provide documentation that demonstrates that the control is technically infeasible. EPA's guidance suggests that documentation that would be considered acceptable includes an explanation, based on physical, chemical, or engineering principles, as to why the control is technically infeasible and a discussion regarding why technical difficulties would preclude the successful use of the control option on the emissions unit under review.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

This step is functionally equivalent to Step 3 in EPA's BART guidelines. EPA's guidelines state that there are two key issues that must be addressed in this step:

(1) States should ensure that the degree of control is expressed using a metric that ensures an "apples to apples" comparison of emissions performance levels among the options; and
(2) States should give appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels.

When choosing an appropriate metric, EPA recommends selecting a metric that properly allows for the comparison of an inherently lower polluting process with a process that can only be addressed through the application of additional pollution controls. As a result, EPA has suggested that it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed (i.e., pounds per million BTU, or pounds per ton of cement produced).

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step is functionally equivalent to Step 4 in EPA's BART guidelines. After identifying the available and technically feasible control technology options, states are expected to analyze the following when making a BART determination:

- Costs of Compliance
- Energy Impacts
- Non-air Quality Environmental Impacts
- Remaining Useful Life

Each state is responsible for presenting an evaluation of each impact along with appropriate supporting information. States should discuss and, where possible, quantify both beneficial and adverse impacts. In general, the analysis should focus on the direct impact of the control alternatives.

<u>Costs of Compliance</u>

In the regional haze rules and its BART guidance document, EPA has stated that states have flexibility in how costs are calculated. EPA has expressed its position that the Control Cost Manual provides a good reference tool for cost calculations, but also provided some flexibility in this matter. If there are elements or sources that are not addressed by the Control Cost Manual, or if there are additional cost methods that were not considered in the BART guidance document, EPA determined that these methods could serve as useful supplemental information.

11.4 Determination of Reasonable Progress Goals

Under Section 308(d)(1) of the Regional Haze Rule states must "establish goals (expressed in deciviews) that provide fore reasonable progress towards achieving natural visibility conditions" for each Class I area. These reasonable progress goals (RPGs) are interim goals that must provide for incremental visibility improvement for the most impaired visibility days, and ensure no degradation for the least impaired visibility days. The RPGs for the first planning period are goals for the year 2018. Based on the steps outlined in Section 11.2, ADEQ has established RPGs for each Class I area in Arizona.

The RPGs provide for visibility improvement at all Class I areas in Arizona on 20% worst days (Table 11.3); however, the goals are less than the URP. It is important to note that the URP represents the mathematical annual average deciview necessary each year to move from the baseline condition to the natural condition for any given Class I area. This annual average decrease does not take into account existing or real world conditions and are not achievable in every instance. The RPGs presented in Table 11.11 are based on ADEQ's evaluation and consideration of the following: the results of the CMAQ modeling described in Section 9.3, which includes "on-the-books" controls and other emission inputs (see Appendix C for list of CMAQ model emission inputs), the results of the four-factor analysis described in Section 11.3.3, and the BART review described in Chapter 10.

Table 11.3 shows that for all but two monitors, there is no degradation on 20% best days. For those areas with no degradation, there is an improvement in visibility conditions in 2018 on best days. ADEQ attributes this predicted improvement to a combination of factors: the numerous "on-the-books" controls included in the CMAQ modeling and significant reductions in mobile sources emissions (as described in Section 11.4.3). The two monitors showing degradation on best days are CHIR1 and SAGU1, representing four Class I areas. Section 11.4.2 contains a discussion of the factors involved and an explanation of why the degradation is occurring.

For the 20% worst days, Table 11.3 shows that the RPGs are short of the URP goal for each Class I area in Arizona. Section 11.4.1 provides an affirmative demonstration why the RPGs for the 20% worst days are justified.

Table 11.4 – Reasonable Progress Goals for 20% Worst and Best Days for Arizona Class I Areas

Arizona Class I Area	20% Worst Days			20% Best Days	
	Baseline (dv)	2018 URP (dv)	2018 Reasonable Progress (dv)	Baseline (dv)	2018 Reasonable Progress (dv)
Chiricahua NM, Chiricahua W, Galiuro W	13.43	11.98	13.35	4.91	4.94
Grand Canyon NP	11.66	10.58	11.14	2.16	2.12
Mazatzal W, Pine Mountain W	13.35	11.79	12.76	5.40	5.17
Mount Baldy W	11.85	10.54	11.52	2.98	2.86
Petrified NP	13.21	11.64	12.85	5.02	4.73
Saguaro NP – West Unit	16.22	13.90	15.99	8.58	8.34
Saguaro NP – East Unit	14.83	12.88	14.82	6.94	7.04
Sierra Ancha W	13.67	12.02	13.17	6.16	5.88
Superstition W	14.16	12.38	13.89	6.46	6.22

Appendix D

Arizona BART – Supplemental Information

I. EXECUTIVE SUMMARY

Sections 169A and 169B of the Clean Air Act were promulgated by Congress in the 1990 Clean Air Act Amendments with the intent of preventing any future, and remedying any existing, impairment of visibility caused by manmade sources in 156 mandatory Class I areas. Through this requirement, Congress set the goal of achieving natural visibility conditions in the Class I areas by 2064. In the interim, States are required to make reasonable progress towards the achievement of this national goal.

Title 40 CFR §§ 51.300 through 309 (the "regional haze rules") implement §§ 169A and 169B of the Clean Air Act and require States to submit state implementation plans (SIPs) to address regional haze visibility impairment in the 156 Class I areas. These SIPs are intended to be the first in a series of actions that will become long term regional haze strategies to demonstrate reasonable further progress toward the goal that Congress set. One of the tools provided to the States to address reasonable further progress is called Best Available Retrofit Technology, or BART.

The regional haze rules use the term "BART-eligible source" to describe the sources that are potentially subject to this program. BART-eligible sources are those sources that have the potential to emit 250 tons or more of a visibility-impairing air pollutant; were constructed between August 7, 1962 and August 7, 1977, and whose operations fall within one or more of the 26 specifically listed source categories. Once a facility has been determined to be BART-eligible, air dispersion modeling tools are used to determine if that facility causes or contributes to regional haze. If a State determines that the facility "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area," then the facility is deemed to be subject-to-BART. Visibility impairing pollutants include emissions of oxides of nitrogen (NOx), sulfur dioxide (SO2) and particulate matter (PM). The term "particulate matter" includes particles with an aerodynamic diameter that is less than 10 microns (µm), and particles with an aerodynamic diameter that is less than 2.5 µm.

On June 9, 2006, ADEQ provided potential emissions information along with stack parameters for each potentially-BART-eligible facility to the Western Regional Air Partnership's (WRAP's) Regional Modeling Center, which performed a CALPUFF modeling analysis to determine the predicted visibility impairment apportioned to each facility.

On June 7, 2007, the WRAP's Regional Modeling Center provided ADEQ with the results of the CALPUFF modeling analysis. Based upon the CALPUFF modeling results, ADEQ determined that if a "potentially-BART-eligible" source's twenty-second highest (98th percentile) visibility impact across the three years of modeling was greater than 0.5 deciviews (dv) in any Class I area less than 300 kilometers away, the facility would be considered to contribute to impairment of visibility in that Class I area. Similarly, if the "potentially-BART-eligible" source's impact was found to be greater than 1.0 dv in any Class I area less than 300 kilometers away, the facility would be considered to cause impairment of visibility in that Class I area. In most cases where a "potentially-BART-eligible" source was found to have emissions that contributed to, or caused, impairment of visibility in a Class I area, ADEQ determined that the facility was "potentially-subject-to-BART." In some cases where a facility's contributions to impairment of visibility in a Class I area were within 20% of 0.5 dv, ADEQ requested that the source provide further information demonstrating that the facility was not "potentially-subject-to-BART." As a result, nine BART-eligible facilities were determined to be potentially-subject-to-BART, and one facility was recommended for further evaluation.

On July 13, 2007, eight sources that were potentially-subject-to-BART and another source that was recommended for further evaluation were provided with a set of three options: (i) demonstrate that the facility is not BART-eligible; (ii) demonstrate that while the facility is BART-eligible, it is not potentially-subject-to-BART as the facility does not cause or contribute to regional haze; or (iii) agree that the facility is potentially-subject-to-BART and conduct a BART analysis for the facility. The one potentially-subject-to-BART facility that did not receive a letter from ADEQ (Tucson Electric Power Company's Irvington Generating Station) was also subject to additional scrutiny. Due to on-going conversations and information that Tucson Electric Power (TEP) had already submitted, ADEQ did not provide that facility a letter on July 13, 2007. The ten facilities and the options that were chosen are as follows:

<u>Option 1: Demonstrate that the facility is not BART-eligible:</u>

TEP - Irvington Generating Station

<u>Option 2: Demonstrate that while the facility is BART-eligible, it is not subject-to-BART:</u>

Arizona Portland Cement Company
APS West Phoenix
ASARCO Hayden Smelter
Chemical Lime Nelson Lime Plant
Freeport-McMoRan Miami Smelter (formerly Phelps Dodge Miami Smelter)

<u>Option 3: Conduct a BART analysis:</u>

Catalyst Paper (Snowflake) Inc. (formerly Abitibi Consolidated)
Arizona Electric Power Cooperative (AEPCO)
APS Cholla Power Plant
SRP Coronado Generating Station

ADEQ analysis of the information that was submitted by each of the companies listed above resulted in the following determinations:

<u>Arizona Sources That Chose to Demonstrate "Not BART-Eligible":</u>

TEP - Irvington Generating Station

<u>Arizona Sources That Chose to Demonstrate Not "Potentially-Subject-to-BART":</u>

Arizona Portland Cement Company
APS West Phoenix
Chemical Lime Nelson Lime Plant

<u>Facilities That Required a BART Analysis:</u>

Catalyst Paper
AEPCO
APS Cholla Power Plant
ASARCO Hayden Smelter
Freeport-McMoRan Miami Smelter
SRP Coronado Generating Station

With the exceptions of the ASARCO Hayden Smelter and the Freeport-McMoRan Miami Smelter, those facilities which were determined to be subject-to-BART agreed with ADEQ's June 13, 2007, letter, and submitted their own analyses of what BART should be for each facility. The Freeport-McMoRan Miami Smelter also provided information about BART applicability to its facility. While the company agreed that BART was applicable to specific emissions units, it provided arguments that the existing controls and emissions limitations at the facility comprised BART. ADEQ reviewed these arguments and, with some supplementary information, was able to conclude that the same arguments applied to the ASARCO

Hayden Smelter. After reviewing the analyses submitted, ADEQ determined that the following controls and emissions limitations constituted BART:

Table 1.1 – NO_X BART		
Facility	**BART Control**	**BART Limit**
Catalyst Paper	**Power Boiler #2:** No additional controls	**Power Boiler #2:** 0.70 lb/MMBtu
AEPCO	**ST1:** LNB with Flu Gas Recirculation (FGR) **ST2:** LNB with OFA **ST3:** LNB with OFA	**ST1:** 0.056 lb/MMBtu **ST2:** 0.31 lb/MMBtu **ST3:** 0.31 lb/MMBtu
APS Cholla Power Plant	**Unit 2:** LNB with Separate Over Fire Air (SOFA) **Unit 3:** LNB with SOFA **Unit 4:** LNB with SOFA	**Unit 2:** 0.22 lb/MMBtu **Unit 3:** 0.22 lb/MMBtu **Unit 4:** 0.22 lb/MMBtu
ASARCO Hayden Smelter	Not Applicable	Not Applicable
Freeport-McMoRan Miami Smelter	Not Applicable	Not Applicable
SRP Coronado Generating Station	**Unit 1:** LNB with OFA **Unit 2:** LNB with OFA	**Unit 1:** 0.32 lb/MMBtu **Unit 2:** 0.32 lb/MMBtu

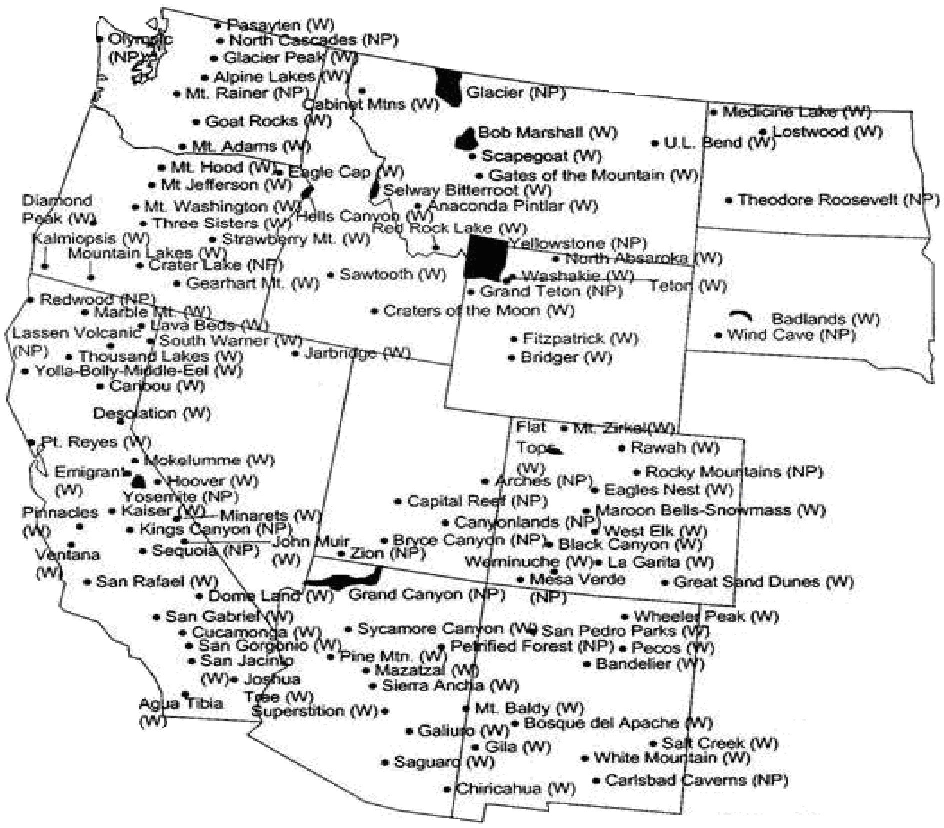
Table 1.2 – PM_{10} BART		
Facility	**BART Control**	**BART Limit**
Catalyst Paper	Not applicable	Not Applicable
AEPCO	**ST1:** Combustion of Pipeline Natural Gas (PNG) **ST2:** Electro Static Precipitator (ESP) Upgrades **ST3:** ESP Upgrades	**ST1:** 0.0075 lb/MMBtu for PNG **ST2:** 0.03 lb/MMBtu **ST3:** 0.03 lb/MMBtu
APS Cholla Power Plant	**Unit 2:** Fabric Filter **Unit 3:** Existing Fabric Filter **Unit 4:** Existing Fabric Filter	**Unit 2:** 0.015 lb/MMBtu **Unit 3:** 0.015 lb/MMBtu **Unit 4:** 0.015 lb/MMBtu
ASARCO Hayden Smelter	Not Applicable	Not Applicable
Freeport-McMoRan Miami Smelter	Existing Controls - Primary Copper Smelting NESHAP	Primary Copper Smelting NESHAP
SRP Coronado Generating Station	Existing Hot Side ESPs	0.03 lb/MMBtu

Table 1.3 – SOx BART		
Facility	**BART Control**	**BART Limit**
Catalyst Paper	**Power Boiler #2:** Upgraded scrubber/Baseline	**Power Boiler #2:** 0.80 lb/MMBtu
AEPCO	**ST1:** Use only PNG **ST2:** Existing Wet Limestone Scrubber **ST3:** Existing Wet Limestone Scrubber	**ST1:** 0.00064 lb/MMBtu for PNG **ST2:** 0.15 lb/MMBtu **ST3:** 0.15 lb/MMBtu
APS Cholla Power Plant	**Unit 2:** Wet Lime Scrubber **Unit 3:** Wet Lime Scrubber **Unit 4:** Wet Lime Scrubber	**Unit 2:** 0.15 lb/MMBtu **Unit 3:** 0.15 lb/MMBtu **Unit 4:** 0.15 lb/MMBtu
ASARCO Hayden Smelter	Existing Controls - Double Contact Acid Plant	Existing Controls
Freeport-McMoRan Miami Smelter	Existing Controls – Double Contact Acid Plant	Existing Controls
SRP Coronado Generating Station	**Unit 1:** Wet FGD **Unit 2:** Wet FGD	**Unit 1:** 0.08 lb/MMBtu **Unit 2:** 0.08 lb/MMBtu

II. Regional Haze Background

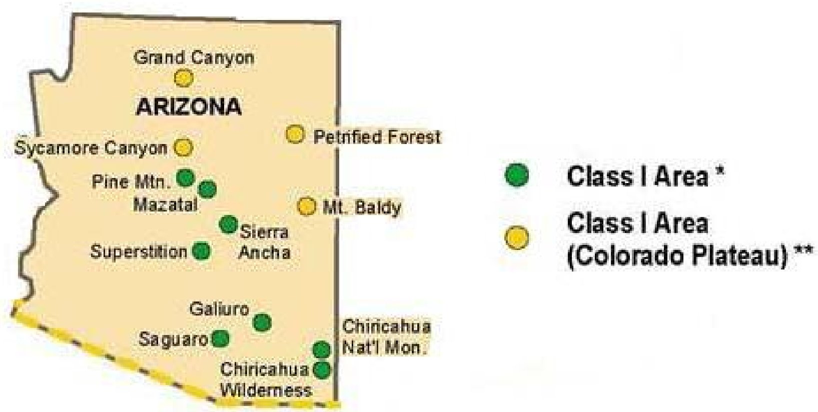
As noted in Section I, there are 156 mandatory, Federally-protected parks and wildernesses throughout the United States that make up Class I areas throughout the country. Of these Class I areas, more than 70 percent (110) are in the Western Continental United States (see Figure 2.1).

Figure 2.1: Class I Areas in the Western Continental United States



Arizona is home to 12 Class I Areas, including the Grand Canyon and Petrified Forest National Parks; the Mount Baldy, Sycamore Canyon, Pine Mountain, Mazatzal, Sierra Ancha, Superstition, Galiuro, Saguaro, and Chiricahua Wilderness Areas; and the Chiricahua National Monument (see Figure 2.2).

Figure 2.2: Arizona Class I Areas



In 1999, EPA adopted regional haze rules that address Congress' stated intent to remedy the existing visibility impairment, and to prevent future visibility impairment in the mandatory Class I areas. Congress also stated its goal that visibility in the Class I areas return to natural conditions by the year 2064. To achieve this, EPA's rules required the States to submit SIPs to address visibility impairment. Arizona's SIP must provide reasonable progress towards the national goal for the 12 Class I areas within the state, as well as address progress in those Class I areas outside Arizona that are impacted by emissions of visibility impairing pollutants originating within the State.

Title 40 CFR 51 §§ 308 and 309 both require States to address visibility impairing pollutant emissions from stationary sources. The principal tool for addressing such emissions is the requirement for specific stationary sources to install BART

III. BACKGROUND FOR BART

Clean Air Act Sections 169A(b)(2) and (g)(7) use the term "major stationary source" to describe those sources that are the focus of the BART requirement. Because this term introduces some potential confusion with other Clean Air Act requirements which also use the term "major stationary source", EPA's regional haze rules coined the term "BART-eligible source" to describe the sources that might be subject to this program. BART-eligible sources are those sources which have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were put into place between August 7, 1962, and August 7, 1977, and whose operations fall within one or more of the 26 specifically listed source categories.

Once a facility has been determined to be BART-eligible, an air dispersion modeling tool is used to determine if that facility causes or contributes to regional haze. If a State determines that the facility "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area," then the facility is deemed to be subject-to-BART. Visibility impairing pollutants include emissions of oxides of nitrogen (NOx), sulfur dioxide (SO2) and particulate matter (PM). The term particulate matter includes particles with an aerodynamic diameter that is less than 10 microns (μm), and particles with an aerodynamic diameter that is less than 2.5 μm.

The regional haze rules at 40 CFR 51.308(e)(1)(ii) require States to address any BART-eligible existing source that is determined by the State to emit any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area. In addressing BART, the Clean Air Act requires the State to consider the following factors:

- The costs of compliance;
- The energy and non-air quality environmental impacts of compliance;
- Any existing pollution control technology already in use at the source;
- The remaining useful life of the source; and
- The degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

Over the course of the regional haze rules, there have been a number of challenges to the provisions of the rules and the methodologies prescribed or accepted by EPA. In 1999, EPA explained in its preamble to the rules that the BART requirements demonstrated Congress' intent to focus attention directly on the problem of pollution from a specific set of sources which, as determined by a State, emit any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area.

Specifically, EPA concluded that if a potentially-subject-to-BART source was located within an area upwind from a downwind Class I area, that source "may reasonably be anticipated to cause or contribute" to visibility impairment in the Class I area. The regional haze rules address visibility impairment resulting from emissions from a multitude of sources that are located across a wide geographic area. The problem of regional haze is caused in large part by the long-range transport of emissions from multiple sources. Therefore, EPA had also concluded that when weighing the factors set forth in the statute for determining BART, the States should consider the collective impact of BART sources on visibility. In particular, when considering the degree of visibility improvement that could reasonably be anticipated to result from the use air pollution control technology, EPA explained that the State should consider the degree of improvement in visibility that would result from the cumulative impact of applying controls to all sources subject-to-BART. EPA then proposed that the States should use this analysis to determine the appropriate BART emission limitations for specific sources.

In American Corn Growers v. EPA, in addition to other challenges to the rules, industry petitioners challenged EPA's interpretations that any source with any potential impacts in any Class I area should be subject-to-BART, and that BART should be applied after considering the collective impacts of BART sources on Class I areas. In 2002, the court concluded that the BART provisions in the 1999 regional haze rule were inconsistent with the provision in the Clean Air Act, as the Act gave the "states broad authority over BART determinations." 291 F.3d at 8.

With respect to the test for determining whether a source is subject-to-BART, the court held that the method that EPA had prescribed for determining which eligible sources are subject-to-BART illegally constrained the authority Congress had conferred to the States. Although the court did not decide whether EPA's proposed general collective contribution approach to determining BART was inconsistent with the Clean Air Act, the court did state that "[i]f the [regional haze rule] contained some kind of a mechanism by which a state could exempt a BART-eligible source on the basis of an individual contribution determination, then perhaps the plain meaning of the Act would not be violated. But the [regional haze rule] contains no such mechanism." Id, at 12.

With respect to EPA's interpretation that the Clean Air Act required the States to consider the degree of improvement in visibility that would result from the cumulative impact of applying controls in determining BART, the court also found that EPA was inconsistent with the language of the Act. 291 F.3d at 8. Based on its review of the statute, the court concluded that the five statutory factors in section 169A(g)(2) "were meant to be considered together by the states." Id. At 8.

On July 6, 2005, EPA took action to address the court's vacatur of the requirement in the regional haze rule requiring States to assess visibility impacts on a cumulative basis in determining which sources are subject-to-BART. Because this requirement was found only in the preamble to the 1999 regional haze rule, EPA concluded that no changes to the regulations were required. Instead, this issue was ultimately addressed by the BART guidelines, which provided States with different techniques and methods for determining which BART-eligible sources "may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area."

The July 6, 2005, amendments to the rules also required the States to consider the degree of visibility improvement resulting from a source's installation and operation of retrofit technology, along with the other statutory factors set out in Clean Air Act § 169A(g)(2), when making a BART determination. This was accomplished by listing the visibility improvement factor with the other statutory BART determination factors in 40 CFR 51.308(e)(91)(A), so that States are now required to consider all five factors, including visibility impacts, on an individual source basis when making each source's BART determination.

IV. ARIZONA "POTENTIALLY-SUBJECT-TO-BART" DETERMINATION PROCESS

A. Identification of Potentially-BART-Eligible Emissions Units

On April 4, 2005, the Stationary Sources Joint Forum (SSJF) of the WRAP published a draft report identifying BART-eligible sources in the WRAP region[1]. This report took a broad-brush approach to reviewing existing stationary sources of air pollution in order to determine whether or not emissions units at the facility could be considered to be BART-eligible. The report explains that the following series of steps were used to identify potentially BART-eligible facilities in the WRAP region:

Step 1: Identify the facilities that are categorical sources (i.e., one of the 26 source categories);

Step 2: Identify whether or not any of the emissions units at the facility are within the date range of BART;

Step 3: Determine whether or not the potential emissions of the entire facility (all emissions units) are greater than 250 tons per year of visibility-impairing pollutants.

B. BART-Eligibility Determination

On June 15, 2005, EPA published final regulatory text and guidelines for implementing BART, including methodologies that are to be used to establish whether or not emissions units at a facility are truly BART-eligible. According to the language of the guidelines, there are three steps for determining which emissions units at a facility are considered to be BART-eligible. Those three steps are summarized as follows:

Step 1: Determine whether the plant contain emissions units in one or more of the 26 source categories:
- a. If no, then emissions units are not BART-eligible.
- b. If yes, proceed to Step 2.

Step 2: Identify the start-up dates of emissions units identified in Step 1. Determine whether the emissions units had begun operation after August 7, 1962 and were in existence on August 7, 1977:
- a. If no, then emissions units are not BART-eligible.
- b. If yes, proceed to Step 3.

Step 3: Compare the potential emissions from all emissions units identified in Steps 1 and 2. Determine whether the combined potential emissions of visibility impairing pollutants from these emissions units are greater than 250 tons per year:
- a. If no, then emissions units are not BART-eligible.
- b. If yes, then emissions units are BART-eligible.

Appendix H of the April 4, 2005, draft SSJF report that identified potentially BART-eligible sources in the WRAP Region specifically recognized a list of sources under the jurisdiction of the Arizona Department of Environmental Quality (ADEQ), the Maricopa Air Quality Department (MCAQD), the

1 See: http://www.wrapair.org/forums/ssjf/bartsources.html

Pima County Department of Environmental Quality (PDEQ) and the Pinal County Air Quality Control District (PCAQCD). Using this list as a basis, ADEQ concluded that 14 distinct sources comprised of 42 separate emissions units in Arizona were "potentially-BART-eligible".

C. Potentially Subject-to-BART

1. Background

After determining BART-eligibility, the State must then determine whether the air pollution emission unit is "potentially-subject-to-BART". EPA finalized several options that allowed States flexibility when making the determination of whether a source "emits any pollutants which may reasonably be anticipated to cause or contribute to any visibility impairment."

Option 1: All BART-eligible sources are Subject-to-BART

EPA provided the States with the discretion to consider all BART-eligible sources within the State to be "reasonably anticipated to cause or contribute" to some degree of visibility impairment in a Class I area. EPA held that this option is consistent with the American Corn Growers court's decision, as it would be an impermissible constraint of State authority for the EPA to force States to conduct individualized analyses in order to determine that a BART eligible source "emits any air pollutant which may reasonably anticipated to cause or contribute to any impairment of visibility in any [Class I] area."

Option 2: All BART-Eligible Sources Do Not Cause or Contribute to Regional Haze

EPA also provided States with the option of performing an analysis to show that the full group of BART-eligible sources in a State may not, as a whole, be reasonably anticipated to cause or contribute to any visibility impairment in Class I areas. Although the option was provided, EPA did also state that it anticipated that in most, if not all, States BART-eligible-sources are likely to cause or contribute to some level of visibility impairment in at least one Class I area.

Option 3: Case-by-Case BART Analysis

The final option that was provided to the States was to consider the individual contributions of a BART-eligible source to determine whether the facility is subject-to-BART. Specifically, EPA allowed States to choose to undertake an analysis of each BART-eligible source in the State in considering whether each such source "emit[s] any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any [Class I] area." Alternatively, States may choose to presume that all BART-eligible sources within the State meet this applicability test, but provide sources with the ability to demonstrate on a case-by-case basis that this is not the case.

2. Arizona Process

When considering the options provided by EPA, ADEQ determined that the third option is the most consistent with the American Corn Growers case, as this option provides a rebuttable method for the evaluation of the visibility impact from a single source. If the air dispersion modeling analysis shows that a facility causes or contributes to Regional Haze, then it is required to address BART. A State is also provided with flexibility under this option, as it may exempt from BART any source that is not reasonably anticipated to cause or contribute to visibility degradation in a Class I area.

As noted in Section IV.B above, fourteen Arizona facilities were determined to be potentially-BART-eligible. On June 9, 2006, ADEQ provided potential emissions information along with stack parameters for each potentially-BART-eligible facility to the WRAP's Regional Modeling Center, which performed a CALPUFF modeling analysis to determine the predicted visibility impairment apportioned to each facility.

On June 7, 2007, the WRAP's Regional Modeling Center provided ADEQ with the results of the CALPUFF modeling analysis. Based upon the CALPUFF modeling results, ADEQ determined that if a "potentially-BART-eligible" source's twenty-second highest (98th percentile) visibility impact across the three years of modeling was greater than 0.5 deciviews (dv) in any Class I area less than 300 kilometers away, the facility would be considered to contribute to impairment of visibility in that Class I area. Similarly, if the "potentially-BART-eligible" source's impact was found to be greater than 1.0 dv in any Class I area less than 300 kilometers away, the facility would be considered to cause impairment of visibility in that Class I area. In every case where a "potentially-BART-eligible" source was found to have emissions that contributed to, or caused, impairment of visibility in a Class I area, ADEQ determined that the facility was "potentially-subject-to-BART." In some cases where a facility's contributions to impairment of visibility in a Class I area were within 20% of 0.5 dv, ADEQ requested that the source provide further information demonstrating that the facility was not "potentially-subject-to-BART." As a result, eight BART-eligible facilities were determined to be potentially-subject-to-BART, and one facility was recommended for further evaluation.

On July 13, 2007, the eight sources that were potentially-subject-to-BART and the source that was recommended for further evaluation were provided with a set of three options: (i) demonstrate that the facility is not BART-eligible; (ii) demonstrate that while the facility is BART-eligible, it is not potentially-subject-to-BART as the facility does not cause or contribute to regional haze; or (iii) agree that the facility is potentially-subject-to-BART and conduct a BART analysis for the facility.

D. Subject-to-BART Determination

Once the "universe" of potentially-BART-eligible sources has been set, the State must make a determination about which of these sources are truly subject-to-BART. In order for a source to be subject-to-BART, a State must conclude that emissions of visibility impairing pollution from a BART-eligible source may reasonably be anticipated to cause or contribute to any visibility impairment in a mandatory Class I area.

As noted in Section V.C above, ADEQ's process only resulted in the determination that certain facilities are potentially-subject-to-BART. The cause for this intermediate step was that ADEQ was unable to access emissions and stack parameter information that is recommended by the EPA BART guidelines for analyzing a facility. Instead, ADEQ relied on information that was publicly available through the Title V permit applications for each of the facilities. Each of the facilities found to be potentially-subject-to-BART was provided with the opportunity to conduct a modeling analysis using emissions estimates that are reflective of steady-state operating conditions during periods of high capacity utilization. In other words, in accordance with the EPA July 6, 2005, BART guidelines, facilities were provided with the option of using of an emissions rate based on the maximum actual emissions over a 24-hour period for the most recent five year periods as an appropriate gauge of a source's potential impact. EPA explained that this would ensure that peak emission conditions are reflected, but would not overestimate a source's potential impact on any given day.

In its analysis of potentially BART-eligible sources, ADEQ identified one facility that appeared to be BART-eligible but deferred sending a letter to that facility, as representatives of the facility were already engaged in dialogue regarding the facility's BART eligibility. Ultimately, the facility chose to demonstrate that it was never BART-eligible.

Arizona Sources That Chose to Demonstrate "Not BART-Eligible":

- TEP Irvington Generating Station

Of the nine facilities that received ADEQ's July 13, 2007, letter, five facilities provided documentation that argued that while the facility was BART-eligible, it was not potentially-subject-to-BART. Those five facilities are as follows:

Arizona Sources That Chose to Demonstrate Not "Potentially-Subject-to-BART":

- Arizona Portland Cement Company
- APS West Phoenix
- ASARCO Hayden Smelter
- Chemical Lime Nelson Lime Plant
- Freeport McMoRan Miami Smelter

Of the facilities that received ADEQ's July 13, 2007, letter, four responded that the facilities were indeed subject-to-BART and provided an BART-analysis for the BART-eligible equipment. Those four facilities are as follows:

Arizona Sources that Agreed To Be Subject-to-BART:

- Catalyst Paper
- AEPCO
- APS Cholla Power Plant
- SRP Coronado Generating Station

VII. ARIZONA SOURCES THAT REQUIRED A BART ANALYSIS

Pursuant to the discussion in the previous Section, the following six facilities were identified as having to conduct a BART analyses. Due to the case-by-case nature of the BART analyses, ADEQ has included specific sections in this technical support documents for each of these facilities. A brief summary of the circumstances leading to ADEQ's subject-to-BART determinations are as follows:

A. Catalyst Paper (Snowflake) Inc. (CPSI) formerly Abitibi Consolidated

On June 13, 2007, ADEQ sent a letter to Abitibi Consolidated indicating that Power Boiler 2, a coal-fired boiler at the paper and pulp mill was "potentially-subject-to-BART" for SO_2 and NO_X emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association, and its review of the Title V Permit Application –Amended Version submitted in March 2000 which showed that the facility had potential NO_X and SO_2 emissions as follows (Table 7.1):

Table 7.1 – ADEQ Modeled Emissions for CPSI

Emissions Unit	NO_X Emissions (lb/hr)	SO_2 Emissions (lb/hr)
Power Boiler 2	555.00	915.00

On October 23, 2007, Abitibi Consolidated provided a BART analyses to ADEQ. ADEQ's analysis and BART determination for CPSI can be found in Section IX of this document.

B. Arizona Electric Power Cooperative, Inc. - Apache Generating Station

On June 13, 2007, ADEQ sent a letter to Arizona Electric Power Cooperative Inc.'s (AEPCO's) Apache Generating Station indicating that Steam Units 1 through 3 were "potentially-subject-to-BART" for NO_X and SO_2 emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association; and its review of the Air Quality Permit Number 35043, and the January 6, 2005, application for Class I Permit Renewal, which showed that the facility had potential NO_X and SO_2 emissions as follows (Table 7.2):

Table 7.2 – ADEQ Modeled Emissions from AEPCO

Emissions Unit	NO_X Emissions (lb/hr)	SO_2 Emissions (lb/hr)
Steam Unit #1	264.90	0.57
Steam Unit #2	576.47	1.24
Steam Unit #3	576.47	1.24

In July of 2007, AEPCO scheduled a meeting with ADEQ to discuss its concurrence that the facility was subject-to-BART. In the meeting, AEPCO indicated that the information that was provided to the WRAP's RMC was based upon Steam Units #2 and #3 burning natural gas, rather than coal. AEPCO discussed a proposed modeling protocol with ADEQ, and explained that when modeling its baseline conditions, AEPCO would use the emission rates associated with burning coal at the facility.

On January 2, 2008, AEPCO provided its BART analysis to ADEQ. ADEQ's analysis and BART determination for AEPCO's can be found in Section XI of this document.

C. APS Cholla Power Plant

On June 13, 2007, ADEQ sent a letter to Arizona Public Service's (APS's) Cholla Generating Station indicating that Steam Units 1 through 4 were "potentially-subject-to-BART" for NO_X, PM, and SO_2 emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association, and its review of the application for Air Quality Permit Number 46353 (Table 7.3):

Table 7.3 – ADEQ Modeled Emissions from APS Cholla

Emissions Unit	NO_X Emissions (lb/hr)	PM Emissions (lb/hr)	SO_2 Emissions (lb/hr)
Unit #1	279.40	38.10	304.8
Unit #2	646.40	293.80	705.10
Unit #3	644.40	87.90	351.50
Unit #4	1,086.80	384.10	3,414.40

In August of 2007, representatives of APS's Cholla Generating Station met with representatives of ADEQ to discuss some outstanding questions that the company had regarding ADEQ's analysis. During the course of that meeting, APS provided a copy of Arizona Public Service Company Correspondence that was sent to Gus Hansen, Supt. at Cholla S.E.S. entitled "Operating Notes for May 1962". According to information provided by this document, "[o]n Tuesday, May 1, 1962, unit [#1] placed into commercial operation." As a result, APS argued that Unit #1 was "in operation" prior to August 7, 1962, and therefore was not BART-eligible. After reviewing this documentation, ADEQ concurs that Unit #1 was never BART-eligible.

On September 13, 2007, APS provided a letter to ADEQ providing a schedule for the submission of a modeling protocol and conducting a BART analysis with the goal of providing the final BART analysis on December 14, 2007. In December of 2007, ADEQ received the BART analysis. ADEQ's analysis and BART determination for the APS Cholla Power Plant can be found in Section XI of this document.

D. ASARCO Hayden Smelter

As discussed in Section VI.C of this document, ADEQ has determined that a BART analysis regarding SO_2 emissions from this facility must be completed. ADEQ's review and determination based upon its own analysis of the facts and the information that ASARCO had provided can be found in Section XII of this document.

E. Freeport-McMoRan Miami Smelter

As discussed in Section VI.E of this document, ADEQ has determined that a BART analysis regarding PM and SO_2 emissions from this facility must be completed. ADEQ's review and determination based upon its own analysis of the facts and the information that Freeport-McMoRan Miami Inc. had provided can be found in Section XIII of this document.

F. SRP Coronado Generating Station

On June 13, 2007, ADEQ sent a letter to Salt River Project's (SRP's) Coronado Generating Station indicating that Units 1 and 2 were "potentially-subject-to-BART" for PM, SO_2 and NO_X emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association, and its review of the August 21, 2003 Application for Class I Permit Renewal which showed that the facility had potential NO_X, PM, and SO_2 emissions as follows (Table 7.4):

Table 7.4 – ADEQ Modeled Emissions for SRP Coronado			
Emissions Unit	**NO_X Emissions (lb/hr)**	**PM Emissions (lb/hr)**	**SO_2 Emissions (lb/hr)**
Unit #1	3,303	472	3,775
Unit #2	3,303	472	3,775

On August 22, 2007, representatives of SRP's Coronado Generating Station met with ADEQ to discuss issues that were unique to the Coronado Generating Station, including a potential settlement with EPA regarding alleged New Source Review violations that would address NO_X and SO_2 emissions. In addition, the company provided a proposed response to ADEQ's request for a BART analysis.

In February 2008, SRP provided its BART analysis to ADEQ. On August 12, 2008, EPA announced a "…major Clean Air Act (CAA) New Source Review (NSR) settlement agreement with [SRP]…" EPA explained that "[u]nder the settlement, SRP will spend over $400 million between now and June 2014, to install state-of-the-art pollution control technology for the reduction of sulfur dioxide (SO_2) and nitrogen oxides (NO_x)."

ADEQ's analysis and BART determination for the SRP Coronado Generating Station can be found in Section XIV of this document.

VIII. ARIZONA BART DETERMINATION PROCESS

Clean Air Act § 169A(g)(7) directs States to consider five factors in making BART determinations. The regional haze rule codified these factors in 40 CFR § 51.308(e)(1)(ii)(B), which directs States to identify the "best system of continuous emissions control technology" taking into account "the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, and the remaining useful life of the source."

The visibility BART regulations define BART as meaning "…an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by … [a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control requirement in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."

In its guidance, EPA was clear that each State must determine the appropriate level of BART control for each source that is determined to be subject-to-BART. In making a BART determination, a State must consider the following factors:

- The costs of compliance;
- The energy and non-air quality environmental impacts of compliance;
- Any existing pollution control technology in use at the source;
- The remaining useful life of the source; and
- The degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

It appears to ADEQ that BART is a close kin to Best Available Control Technology (BACT). Both control technology requirements are based upon similar concepts, including the fact that both are conducted on a case-by-case basis, and both may constitute the application of production processes or available methods, systems and techniques to reduce air pollution emissions. The most significant difference between the two appears to be that BART must accommodate issues associated with retrofitting existing equipment with new air pollution controls that were not included in the initial design of the facility. Since the concepts between the two technology requirements are reasonably similar, ADEQ has determined that it is reasonable method for conducting a BART analysis is following the BACT methodology, taking specific care to address all five of the BART factors.

The Department's framework for performing a BART analysis comprises the following seven key steps:

1. Identify the existing control technologies in use at the source (BART factor 3);
2. Identify all available retrofit control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
3. Eliminate all technically infeasible control technologies;
4. Evaluate control effectiveness of remaining technologies;
5. Evaluate energy and non-air quality environmental impacts and document results (BART factors 1, 2 and 4); and
6. Evaluate visibility impacts (BART factor 5).
7. Select BART

Materials considered by the applicant and by the Department in identifying and evaluating available control options include the following:

- Entries in the RACT/BACT/LAER Clearinghouse (RBLC) maintained by the U.S. EPA, is the most comprehensive and up-to-date listing of control technology determinations available;
- Information provided by pollution control equipment vendors;
- Information provided by industry representatives; and
- Information provided by other Regional Planning Organizations and State permitting authorities.

Step 1: Identify the Existing Control Technologies in Use at the Source

This step is in addition to the five steps that are recommended in Section IV.D of 40 CFR Part 51, Appendix Y ("EPA's BART guidelines"). Of the four facilities that have agreed that they are "potentially-subject-to-BART", two are already in a process of designing or installing new air pollution control devices on emissions units that are "potentially-subject-to-BART". Since the installation of these controls was not required by BART, ADEQ determined that it was appropriate to include a step that described the existing control technologies that provide the baseline against which BART will be judged.

Step 2: Identify All Available Retrofit Control Options

This step is functionally equivalent to Step 1 in EPA's BART guidelines.

At the outset of any BART analysis, EPA's guidelines suggest that States should consider all control options that have potential application to the emissions unit, regardless of technical feasibility. This includes having an understanding of other required controls, including those technologies that are required under BACT or Lowest Achievable Emissions Rate (LAER) determinations, pollution prevention practices, the use of other add-on controls, and upgrades to existing air pollution controls that are already in place. As with BACT and LAER determinations, control alternatives can also take into account technology transfer of controls that have been applied to similar source categories. Unlike some permitting authorities' BACT and LAER procedures, however, BART does not contain a requirement to redesign the source when considering available control alternatives. For example, an existing pulverized-coal-fired electricity generating facility should not be required to consider integrated gasification coal combustion during the BART process, as BART focuses on technologies that can be retrofitted to the existing equipment.

In BACT and LAER determinations, any New Source Performance Standard (NSPS) or National Emissions Standard for Hazardous Air Pollutants (NESHAP) that exists for a source category is considered to the "floor" level of control, meaning that any proposed emission rate or control technology that is less stringent than the NSPS or NESHAP is not acceptable. Because BART involves retrofitting technology to existing emissions units that are not undergoing a major modification, it is possible, albeit unlikely, that an NSPS or NESHAP for a source category might not be the "floor" control for BART. Regardless, where a NSPS or NESHAP exists for a source category, EPA has directed States to include a level of control equivalent to the NSPS or NESHAP as one of the control options to be considered.

For some emissions units that are subject-to-BART controls, the actual control measures or devices that comprise BART may already be in place. In such instances, the BART analysis should consider improvements to the existing controls or emissions limitations for those emissions units, and should not be limited to consideration of only the control devices themselves.

Finally, in some cases, if a State determines that a BART source already has controls in place which are the most stringent controls available, then it may not be necessary to comprehensively complete each following step of the BART analysis. EPA's guidance states that as long as the most stringent controls are made federally enforceable for the purposes of implementing BART for that source, a State may skip the remaining analyses, including the visibility analyses. Likewise, if a source commits to the most stringent level of BART control at the outset, then EPA's guidance suggests that there is no need to complete the remaining steps of the BART process.

Step 3: Eliminate All Technically Infeasible Control Options

This step is functionally equivalent to Step 2 in EPA's BART guidelines.

In this step, States are to evaluate the technical feasibility of the control options that were identified in Step 1. EPA's guidance generally considers a control option to be technically feasible if the controls have either: (1) been installed and operated successfully under similar conditions for the type of source under review, or (2) are available and could be applicable to the source under review. EPA's guidance states that a technology should be considered to be available if the source owner may obtain the control device through commercial channels, or the control is otherwise available within the common sense meaning of the term. Similarly, EPA considers an available control technology to be "applicable" if the control can be reasonably installed and operated on the source type that is under review. If a technology is considered to be both available and applicable, a State should consider the technology to be technically feasible.

If a technology is determined to be technically infeasible, then the State should provide documentation that demonstrates that the control is technically infeasible. EPA's guidance suggests that documentation that would be considered acceptable includes an explanation, based on physical, chemical, or engineering principles, as to why the control is technically infeasible and a discussion regarding why technical difficulties would preclude the successful use of the control option on the emissions unit under review.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

This step is functionally equivalent to Step 3 in EPA's BART guidelines. EPA's guidelines state that there are two key issues that must be addressed in this step:

(1) States should ensure that the degree of control is expressed using a metric that ensures an "apples to apples" comparison of emissions performance levels among the options; and

(2) States should give appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels.

When choosing an appropriate metric, EPA recommends selecting a metric that properly allows for the comparison of an inherently lower polluting process with a process that can only be addressed through the application of additional pollution controls. As a result, EPA has suggested that it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed (i.e., pounds per million BTU, or pounds per ton of cement produced).

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step is functionally equivalent to Step 4 in EPA's BART guidelines. After identifying the available and technically feasible control technology options, States are expected to analyze the following when making a BART determination:

- Costs of Compliance
- Energy Impacts
- Non-air Quality Environmental Impacts
- Remaining Useful Life.

Each State is responsible for presenting an evaluation of each impact along with appropriate supporting information. States should discuss and, where possible, quantify both beneficial and adverse impacts. In general, the analysis should focus on the direct impact of the control alternatives.

Costs of Compliance

In the regional haze rules and its BART guidance document, EPA has stated that States have flexibility in how costs are calculated. EPA has expressed its position that the Control Cost Manual provides a good reference tool for cost calculations, but also provided some flexibility in this matter. If there are elements or sources that are not addressed by the Control Cost Manual, or if there are additional cost methods that were not considered in the BART guidance document, EPA determined that these methods could serve as useful supplemental information.

EPA's guidance also explains that States should consider both the average and incremental annualized costs of a control, as both provide information that is helpful when making a control determination. EPA took great care to explain, however, that these kinds of calculations can be misused, and that both numbers should be reviewed carefully.

In its guidance, EPA provided an example where a State may be faced with choosing between two available control options. The first control option (Option A) achieves a good level of control for a reasonable cost. The second control (Option B) achieves a slightly greater emissions reduction at a significantly increased cost. In this scenario, EPA explained that if only the average costs for Options A and B were considered, the overall costs associated with Options and B would be considered reasonable. EPA stated that while this may seem sufficient, a State should continue to look at the cost associated with a small increase in pollution control for a significantly greater price. EPA called this cost the "incremental cost" and explained that it can be determined through the following equation:

$$\frac{[CostOptionA - CostOptionB]}{[TotalAnnualEmissionsOptionA - TotalAnnualEmissionsOptionB]}$$

EPA explained that by considering this incremental cost, a State may determine that the incremental cost per unit of pollution removed that is associated with Option B may be greater than the benefit of requiring the control. As a result, even though the average cost associated with both controls might be reasonable, the incremental cost may make one option more desirable than the other.

As stated in the introduction to this Section, ADEQ sees the BART determination process as being substantially similar to the BACT processes. While BACT has components that address visibility, the principal cost decisions are generally charged only to the pollutant that is being reduced. Visibility impacts, on the other hand, are quantified and considered as an environmental impact, rather than an economic impact. As a result, the most useful cost metric for comparing control technologies under BACT and LAER ends up being dollars-per-ton-of-pollutant-removed (dollars per ton).

Although the BART determination process is substantially similar to methodologies that are used to establish BACT and LAER, the entire purpose behind BART is to support Congress' goal of reducing visibility impairment in Class I areas. In addition, BART differs from BACT and LAER in that the environmental impacts of the selected control can only address issues that are not related to air quality. As a result, ADEQ has determined that in addition to a dollar per ton metric, the BART determination process should also provide lesser consideration to a dollar-per-deciview-improvement metric.

Energy Impacts

In its guidance, EPA suggests that States should also examine the energy requirements of the control technology to determine whether the use of that technology will result in energy penalties or benefits. For instance, if a control technology is required to remediate an emissions stream that is rich in volatile organic compounds, a facility might benefit by using this combustion process to reduce energy costs. Conversely, a facility that installs a wet scrubber may suffer an energy penalty due to the increased power necessary to overcome the increased air flow resistance through the scrubber.

It should be noted that unless there is ample justification, only direct energy benefits or penalties should be considered in this analysis. Indirect energy costs should not be considered unless there is something unusual or significant enough to warrant further consideration. It is appropriate for energy impact analyses to consider the local availability (or scarcity) of specific fuels, as well as the potential differences between locally or regionally available coals.

It is also important to note that adverse energy impacts are not enough, in and of themselves, to disqualify a technology from consideration. If such penalties or benefits exist, however, it is appropriate to document these and include them in this section so that the results of all of the analyses required in this Step can be considered as a whole.

Non-Air Quality Environmental Impacts

This portion of the analysis is to focus on impacts to environmental media other than air quality. Examples of common environmental impacts include hazardous waste generation, hazardous waste discharges, and discharges of polluted water from a control device.

All non-air quality environmental impacts should be reviewed using site-specific circumstances when possible. Should a State propose to adopt the most stringent BART option then it is not necessary to perform this analysis of environmental impacts for the entire list of technologies that were ranked in the previous Step. In general, the analysis only needs to address those control alternatives with any significant or unusual environmental impacts that have the potential to affect the selection of a control alternative, or to eliminate a more stringent control technology.

In general, States should identify and document any direct or indirect, significant or unusual environmental impacts that are associated with a specific control alternative. For example, a wet scrubber will release effluent that has the potential to affect water or land use. Other examples might include disposal of spent catalyst, or contaminated carbon from a filtration device. Such types of environmental impacts could become even more important with the potential for sensitive site-specific receptors, or when comparing control technologies that have similar or marginal air quality improvements but result in substantial environmental impacts.

Remaining Useful Life

The remaining useful life of a source should be considered in the evaluation of the different controls, as it has the potential to impact the overall cost analysis. If the remaining useful life represents a relatively short period of time, then the annualized costs associated with the application of a control technology will increase significantly. EPA explained in its guidelines that the remaining useful life is the difference between the date that controls will be put into place and the date that the facility permanently stops operations.

If the remaining useful life of the facility affects the BART determination, then this date should be placed into a federally or State-enforceable restriction that prevent further operation of that facility after that date. If a source wants to have the flexibility to continue operating after the date upon which operations are expected to cease, then the BART analysis may account for the option, but it must maintain consistency with the statutory requirement to install BART within 5 years. In addition, if the remaining useful life changes the BART decision as a result of adverse cost impacts, then the BART determination should identify the more stringent level of control that would be required as BART if there was no assumption that reduced the remaining useful life of the facility.

Step 6: Evaluate Visibility Impacts

This step is functionally equivalent to Step 5 in EPA's BART guidelines.

Once a State has determined that its source or sources are subject-to-BART, a visibility improvement determination for the source(s) must be conducted as part of the BART determination. States have the flexibility in setting absolute thresholds, target levels of improvement, or de minimis levels for visibility improvement since the deciview improvement must be weighed among the five factors. States are also free to determine the weight and significance to be assigned to each factor. For example, a 0.3 dv improvement may merit a stronger weighting in one case versus another. As a result, EPA does not recommend a "bright line" analysis to be used across all facilities that are subject-to-BART.

EPA's guidelines recommend the use of CALPUFF or another appropriate dispersion model to determine the visibility improvement expected at a Class I area from the potential BART control technology applied to the source. Modeling should be conducted for NO_X emissions, direct PM emissions ($PM_{2.5}$ or PM_{10}), and SO_2 emissions. If the source is making the visibility determination, States should review and approve or disapprove the source's analysis before making the expected improvement determination.

Arizona instituted a portion of this process by asking sources for a modeling protocol for each of the BART analyses that were submitted. Each source was then asked to run its model at pre-control and post-control emission rates using the accepted methodology in the protocol. Sources used the 24-hour average actual emissions rate from the highest emitting day of the meteorological period modeled, and calculated the model results for each receptor as the change in deciviews compared against natural visibility conditions. Post-control emissions rates were then calculated as a percentage of pre-control emissions rates.

Step 7: Select BART

This step is in addition to the five steps that are recommended in EPA's BART guidelines.

States have discretion to determine the order in which they should evaluate control options for BART. EPA's guidance states that whatever the order, States should always address the five factors. In addition, States should provide a justification for whatever control option is selected. ADEQ has determined that the contents of the TSD will provide the necessary explanations.

X. ARIZONA ELECTRIC POWER COOPERATIVE – APACHE GENERATING STATION BART ANALYSIS AND DETERMINATION

A. Process Description

The Apache Generating Station consists of seven electric generating units (two coal/natural gas-fired steam electric units, a natural gas/fuel oil-fired steam electric, combined cycle unit, and four natural gas/fuel oil-fired turbines) with a total generating capacity of 560 megawatts (MW). The power plant is located approximately 3 miles southeast of the town of Cochise in the Wilcox Basin in Cochise County, Arizona. Apache Steam Unit 1 is a wall-fired steam electric generating unit that can burn natural gas and numbers 2 through 6 fuel oils. The unit is permitted to produce up to a maximum capacity of 85 MW of electricity. Steam Units 2 and 3 are 195 MW natural gas and coal-fired steam electric generating units equipped with dry-bottom turbo-fired coal boilers manufactured by Riley Stoker.

The remaining four units at the Apache Generating Station are simple cycle gas turbines. Steam Unit 1 and Gas Turbine 1 can be operated separately or in a combined cycle configuration.

B. Description of Emissions Units Subject to Best Available Retrofit Technology (BART)

Apache Generating Station Units 1, 2, 3 are potentially subject-to-BART because:

1. These units belong to one of the 26 categorical sources;
2. These units were in existence on August 7, 1977;
3. Emissions of visibility impairing pollutants from all BART-eligible emissions units - nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM) – are greater than 250 tons per year for each pollutant.

The simple cycle gas turbines at the Apache Generating Station are not BART-eligible, and therefore were not considered as part of this analysis.

C. Impact on Visibility

CALPUFF modeling was performed at nine Class I areas that are located within 300 kilometers of the Apache Generating Station. Table 10.1 provides the baseline maximum impact on visibility in deciview (98th percentile, 3-year average).

Table 10.1 – Modeled Baseline Impact on Visibility			
Affected Class I Area	**Unit 1 (dv)**	**Unit 2 (dv)**	**Unit 3 (dv)**
Chiricahua NM	2.75	2.47	2.37
Galiuro Wilderness	1.58	1.92	1.75
Saguaro NP	1.98	1.69	1.55
Gila Wilderness	0.45	0.76	0.69
Superstition	0.98	1.49	1.35

Table 10.1 – Modeled Baseline Impact on Visibility			
Affected Class I Area	**Unit 1 (dv)**	**Unit 2 (dv)**	**Unit 3 (dv)**
Wilderness			
Mt. Baldy Wilderness	0.32	0.45	0.41
Sierra Ancha Wilderness	0.62	0.89	0.80
Mazatzal Wilderness	0.81	0.85	0.76
Pine Mountain Wilderness	0.68	0.68	0.61

The impact of Units 1, 2, and 3 on the visibility in at least one Class I area is more than 0.5 Deciviews. Therefore, per 40 CFR Part 51, Appendix Y, these units cause or contribute to visibility impairment and are subject-to-BART.

D. Steam Unit 1 (ST1)

D.1 NO_X BART Analysis

NO_X formation in fossil fuel-fired boilers is a complex process that is dependent on a number of variables, including operating conditions, equipment design, and fuel characteristics. A NO_X BART analysis was completed for the cases when ST1 burns 100 percent pipeline natural Gas (PNG), 100 percent No. 6 fuel oil (this was done as a test case, as AEPCO has never combusted No. 6 fuel oil in the unit), and 100 percent No. 2 fuel oil.

Formation of NO_X

During combustion, NO_X forms in three different ways: thermal NO_X, fuel NO_X, and prompt NO_X. When combusting PNG, the most dominant source of NO_X is from thermal NO_X, which results from high-temperature fixation of atmospheric nitrogen in the combustion air. Because PNG generally contains small quantities of nitrogen, the overall contribution from fuel NO_X is small, whereas a significant amount of fuel NO_X can be generated from fuel oil combustion. A very small amount of NO_X is called "prompt" NO_X. Prompt NO_X results from an interaction of hydrocarbon radicals, nitrogen, and oxygen.

Step 1: Identify the Existing Control Technologies in Use at the Source

There is no NO_X emissions control equipment installed on ST1.

Step 2: Identify All Available Retrofit Control Options

The second step of the BART process is to evaluate NO_X control technologies with practical potential for application to ST1, including those control technologies identified as BACT or LAER by permitting agencies across the United States. ST1 NO_X emissions are currently controlled through the use of good combustion practices.

The following potential NO_X control technology options were considered:

- New LNBs with OFA
- Flue Gas Recirculation (FGR)
- Rotating Opposed Fire Air (ROFA)
- LNBs with selective non-catalytic reduction system (SNCR and Rotamix)
- LNBs with selective catalytic reduction system (SCR)
- Neural Net Controls

New LNBs with OFA System. The mechanism used to lower NO_X with LNBs is to stage the combustion process and provide a fuel-rich condition in the initial stages of combustion; this is so oxygen needed for combustion is not diverted to combine with nitrogen resulting in the formation of NO_X. Fuel-rich conditions favor the conversion of fuel nitrogen to nitrogen dioxide (N2) instead of NO_X. Additional air (or OFA) is then introduced downstream in a lower temperature zone to burn out the char, or remaining uncombusted fuel. Both LNBs and OFA are considered to be a capital cost, combustion technology retrofit that may require water wall tube replacement.

FGR. FGR generally extracts flue gas from downstream of the economizer or air heater and is mixed into the combustion air duct. This recirculation can be achieved with a new FGR fan or by using the existing forced-draft fan to inject the flue gas into the combustion air (induced flue gas recirculation [IFGR]). Flue gas recirculation adds oxygen-lean, heat-absorbing mass to the combustion air, thus lowering the combustion temperature and reducing thermal NOx emissions.

ROFA. Mobotec markets ROFA as an improved, second-generation OFA system. Mobotec states that "the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles. Rotation is reported to prevent laminar flow, so that the entire volume of the furnace can be used more effectively for the combustion process. In addition, the swirling action reduces the maximum temperature of the flames and increases heat absorption. The combustion air is also mixed more effectively."

A typical ROFA installation will have a booster fan(s) to supply the high velocity air to the ROFA boxes. Mobotec would propose one 700 horsepower fan for ST1. Mobotec's budgetary proposals included expected NOx emission rates for PNG and No. 2 and No. 6 fuel oils, and are presented in Table 2. While a typical installation does not require modifying an installed LNB system, and the existing OFA ports are not used, results of computational fluid dynamics modeling will determine the quantity and location of new ROFA ports. Although not specifically identified, Mobotec generally includes bent tube assemblies for OFA port installation if required. Mobotec does not provide installation services, because they believe that the owner can more cost-effectively contract for these services. However, they do provide one onsite construction supervisor during installation and startup.

SNCR. SNCR is generally used to achieve modest NOx reductions on smaller units. With SNCR, an amine-based reagent such as ammonia—or more commonly urea—is injected into the furnace within a temperature range of 1,600 degrees Fahrenheit (°F) to 2,100°F, where it reduces NO_X to nitrogen and water. NO_X reductions of up to 60 percent have been achieved, although 20 to 40 percent is a more realistic expectation for most applications. Reagent utilization, which is a measure of the efficiency with which the reagent reduces NO_X, can range from 20 to 60 percent, depending on the amount of reduction, unit size, operating conditions, and allowable ammonia slip. With low-reagent utilization, low temperatures, or inadequate mixing, ammonia slip occurs, allowing unreacted ammonia to create problems downstream. Typical problems include rendering the fly ash unsellable, reacting with sulfur to foul heat exchange surfaces, or creating a visible stack plume. Reagent utilization can have a significant impact on economics in that each incrementally higher level of NO_X reduction generally results in lower reagent utilization and higher operating cost.

Reductions from higher baseline concentrations (inlet NO_X) are lower in cost per ton, but result in higher operating costs, due to greater reagent consumption. Budgetary proposals were received from Mobotec for their Rotamix system, and previous Fuel Tech proposal information for other projects was used.

SCR. SCR works on the same chemical principle as SNCR but instead uses a catalyst to promote the chemical reaction. Ammonia is injected into the flue-gas stream, where it reduces NO_X to nitrogen and water. Unlike the high temperatures required for SNCR, in SCR the reaction takes place on the surface of a vanadium/titanium-based catalyst at a temperature range between 580°F and 750° F. Due to the catalyst, the SCR process is more efficient than SNCR and results in lower NO_X emissions.

Neural Net Controls. Information regarding neural net controls was received from NeuCo, Inc. While NeuCo offers several neural net products, CombustionOpt and SootOpt provide the potential for NOx reduction. NeuCo stated that these products can be used on most control systems and can be effective even in conjunction with other NO_X reduction technologies. NeuCo predicts that CombustionOpt can reduce NO_X by 15 percent, and SootOpt can provide an additional 5 to 10 percent. Because NeuCo does not offer guarantees on this projected emission reduction, a nominal reduction of 15 percent was assumed for evaluation purposes.

Because NeuCo does not guarantee NO_X reduction, ADEQ has determined that the estimated emission reduction levels provided cannot be considered as reliable projections. Therefore, neural net should be considered as a supplementary or "polishing" technology, but not on a "stand-alone" basis.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the identified control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Table 10.2 lists the various control technologies and estimated emissions rates.

Table 10.2 – NO_X Control Technology Emission Rate Ranking

Technology	Source of Estimated Emissions	Estimated Emission Rate[4] (PNG)	Estimated Emission Rate (No. 6 Fuel Oil)[d]	Estimated Emission Rate (No. 2 Fuel Oil)[d]
LNB with FGR[e]	Coen	0.056	0.15	0.06
ROFA[b]	Mobotec	0.08	0.16	0.08
ROFA with Rotamix[b]	Mobotec	0.06	0.11	0.06
LNB with FGR, SNCR	Coen & Fuel Tech	0.06[c]	0.11[c]	0.05[c]
SCR[a]	CH2M Hill	0.07	0.07	0.07

[a] SCR estimated NO_X emissions rate is the same for all scenarios. Operating cost would be affected by inlet NO_X levels.
[b] Calculated from Mobotec proposal information fuel baselines (47 percent reduction for ROFA and additional 30 percent for Rotamix)
[c] From Previous Fuel Tech Proposal at 25 percent reduction
[d] Results are in lb/MMBtu
[e] From Coen Proposal

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts

Installation of LNBs is not expected to significantly impact the boiler efficiency or forced-draft fan power usage. Therefore, these technologies will not have energy impacts. The Mobotec ROFA system requires installation and operation of one 700 horsepower ROFA fan (522 kilowatts [kW] total). An estimated auxiliary power requirement for an SNCR system for an 85-MW (with the 10-MW combustion turbine included) unit is estimated at 85 kW. The same estimate was used for Rotamix. SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase.

Environmental Impacts

Environmental impacts associated with SCR and SNCR involve the hazards associated with the storage of ammonia, especially if anhydrous ammonia is used, and the transportation of the ammonia to the power plant site.

Economic Impacts

Costs and emissions estimates for the LNBs, SNCR, and SCR were obtained from equipment vendors. Costs for the ROFA and Rotamix systems were obtained from Mobotec. A comparison of the technologies on the basis of costs, design control efficiencies, and tons of NO_X removed is summarized in Table 10.3. The capital costs shown in Table 3 are applicable for all of the fuels under consideration, and No. 6 fuel oil was used as the basis to determine worst-case emission levels. For example, if LNBs are installed for PNG, the burner costs include the capability to burn both PNG and No. 2 and 6 fuel oils (with only minor equipment modification, atomization changes, and burner control revisions). Similarly, the cost information for any of the NO_X reduction technologies listed in Table 3 will apply for the fuel alternatives under consideration. Costs for LNBs are presented with FGR because this scenario is representative of current operation of ST1 when it is operated in combined cycle with Gas Turbine #1. Costs for LNBs without FGR would be lower. The complete Economic Analysis is contained in Appendix A of the AEPCO BART submittal.

Table 10.3: NO_x Control Cost Comparison					
Factor	**ROFA[c]**	**LNB with FGR**	**LNB with FGR & SNCR[b]**	**ROFA with Rotamix**	**LNB with SCR[a]**
Total installed capital cost (Million $)	$2.700	$1.184	$4.584	$4.457	$25.50
Total installed capital cost + additional owner costs (Million $)	$4.725	$2.072	$5.730	$7.800	$31.88
Total first year fixed and variable O&M costs (Million $)	$0.145	$0.204	$0.116	$0.195	$0.346
Total first year annualized cost	$0.939	$0.552	$1.079	$1.506	$5.705
Power consumption (MW)	0.52	0.85	0.09	0.52	0.43
Annual power usage (Million kW-hr/yr)	1.9	3.1	0.3	1.9	1.5
NOx design control efficiency	46.8%	50.2%	63.5%	63.5%	76.7%
Tons NOx removed per year	278	297	376	376	455
First year average control cost ($/ton removed)	$3,382	$1,856	$2,870	$4,004	$12,542
Incremental control cost ($/ton removed)	-$19,659	$1,856	$1,425	---[d]	$53,311

[a] Based on $300 per kW SCR factored estimate for 85 megawatts
[b] Based on $40 per kW SNCR factored estimate for 85 megawatts
[c] ROFA has a negative incremental control cost because when compared with LNB with FGR the technology costs more and removes less tons of NO_x
[d] The incremental control cost for ROFA with Rotamix when compared with LNB with FGR and SNCR results in a non number as the two technologies have the same NO_x removal in tons per year

Step 6: Evaluate Visibility Impacts

Table 10.4 below shows the total deciview reduction for the most impacted Class I area. For ST1, the most impacted Class I area is the Chiricahua Wilderness Area and National Monument.

Table 10.4 – Control Technologies and Respective Deciview Reduction			
Control	**Deciview Reduction**	**Total Annualized Cost (Million $)**	**Cost per deciview reduced (Million $/deciview reduced)**
LNB with FGR	0.194	0.552	2.845
ROFA	0.256	0.939	3.668
ROFA with Rotamix	0.240	1.506	6.274

Table 10.4 – Control Technologies and Respective Deciview Reduction			
Control	Deciview Reduction	Total Annualized Cost (Million $)	Cost per deciview reduced (Million $/deciview reduced)
LNB with FGR and SNCR	0.240	1.079	4.497
SCR	0.409	5.705	13.948

Step 7: BART Determination

After reviewing the company's BART analysis, and based upon the information above ADEQ has determined that, for Unit 1, BART for NO_X is the installation of LNB with FGR (from GT1) with a NO_X emissions limit of 0.056 lb/MMBtu when burning pipeline quality natural gas (PNG). Fuel oil will not longer be an authorized fuel for Unit 1. the limit would apply on a 30-day rolling average basis.

D.2 PM_{10} BART Analysis

The PM_{10} BART analysis is only completed for the case when ST1 burns 100 percent No. 6 fuel oil. This was done for comparison only, as AEPCO has never combusted No. 6 fuel oil in the unit).

Step 1: Identify the Existing Control Technologies in Use at the Source

There is no emissions control equipment installed on ST1.

Step 2: Identify All Available Retrofit Control Options

The following retrofit control technologies have been identified for PM_{10} control on ST1:

- Use of low-sulfur fuel oil (No. 2 fuel oil)
- Switch to PNG
- New LNBs/particulate matter burner
- Dry electrostatic precipitator (ESP)
- Wet ESP
- Fabric filter

Low Sulfur Distillate Oil. Particulate matter emissions would be reduced with the switching of fuel oil grades from No. 6 to No. 2. PM_{10} emissions while burning No. 2 fuel oil are estimated at 0.0143 lb/MMBtu.

Switch to PNG. Expected PM_{10} emissions when burning PNG are estimated at 0.0075 lb/MMBtu.

New LNBs/Particulate Matter Burner. With the Coen LNB, particulate matter emissions are also reduced. From the budgetary information received from Coen, particulate matter emissions are estimated at less than 0.03 lb/MMBtu and 0.0015 lb/MMBtu while burning No. 6 fuel oil (with LNB and IFGR), and No. 2 fuel oil (LNB), respectively.

Dry ESP. A dry ESP operates by first placing a charge on the particulates though a series of electrodes, and then capturing the charged particulates on collection plates. While an ESP can be designed for high-particulate removal, operation is susceptible to particle resistivity, which denotes a collected particle's ability to ultimately discharge to the collection plate. Low-resistivity particles can be easily charged but may quickly lose their charge at the collection plate and tend to be re-entrained into the flue gas stream. Higher resistivity particles may form a "back corona," which is caused by a layer of non-conductive particles being formed on the collection plate. Back corona may prevent other charged gas stream particles from migrating to the collection plate. Particle resistivity is also influenced by flue gas temperature. ESP sizing is in large part determined by particulate size, with larger ESP size required when smaller particulates are expected. In addition, the particulates from an oil-fired unit tend to be small and sticky, and if a Spray Dryer Absorber is used for SO_2 reduction, there will be a greatly increased inlet particulate loading to the ESP. Because of the uncertainty in chemical and physical characteristics of the oil-fired particulate, ADEQ determined that a dry ESP is not a good technological match for ST1.

Wet ESP. While wet ESP operation is similar to the dry ESP through the charging and collection of flue gas particulates, the wet technology has significant advantages. The wet ESP is not sensitive to particulate resistivity and can accommodate changes in particulate loading more easily than a dry ESP. Collection plates can be created from metal or fabric, and the collected particulate is washed off the plates with water.

Wet ESPs have successfully been demonstrated on similar oil particulate or chemical mist applications. However, flue gas leaving the wet ESP will be saturated and may result in a visual steam plume exiting the stack. The wet ESP will use water to collect and remove the particulates, and will produce a wastewater byproduct. While the wet ESP PM_{10} emission level is estimated to be similar to a fabric filter without SDA operation, increased particulate loading from an SDA may not allow a wet ESP to meet required collection efficiency. Therefore, ADEQ has determined that a wet ESP is not a technically acceptable alternative when matched with an SDA.

Fabric Filter. Fabric filter technology achieves particulate reduction through the filtration of the flue gas through filter bags. The collected particles are periodically removed from the bag through a pulse jet or reverse flow mechanism. A pulse jet filtration system would likely be selected for installation on ST1, because this fabric filter technology results in lower capital cost and a smaller required footprint.

Because of the somewhat sticky particles produced during oil firing, using an appropriate fabric or coating bags with a suitable pre-coat material is imperative. If fabric bags become "blinded" by allowing hard-to-remove particulates to become embedded in the fabric structure, total bag replacement may be necessary. Blinded bags will continue to provide excellent filtration efficiencies; however, the pressure drop across the fabric may exceed system draft capability.

ADEQ has determined that while a fabric filter is not an acceptable alternative for particulate matter/PM_{10} emissions control for an oil-fired unit without using a coating material for the bags, it is anticipated to function satisfactorily with a pre-coat and the increased particulate loading from the SDA operation.

<u>Step 3: Eliminate All Technically Infeasible Control Options</u>

ADEQ has determined that all of the identified control technologies are technically feasible, with the exception of wet and dry ESPs, for the reasons discussed in Step 1 above.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

ST1 particulate matter emissions are currently estimated at 0.0737 lb/MMBtu while burning No. 6 fuel oil. The BART PM_{10} analysis will be completed only for the case of firing 100 percent No. 6 fuel oil. The PM_{10} control technology emission rates are summarized in Table 10.5. No capital costs are associated with switching to PNG.

Table 10.5 – PM_{10} Control Technology Emission Rates	
Control Technology	**Expected PM_{10} Emission Rate (lb/MMBtu)**
Current Baseline	0.0737
Fabric Filter	0.015
New LNB[a]	0.0015
Switch to PNG	0.0075

[a] When burning No. 2 fuel oil

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts

No additional energy impact is expected from PM_{10} reduction as a result of a new LNBs/particulate matter burner retrofit or burning of low-sulfur fuel oil. A fabric filter and ductwork will add an estimated 6 to 8 inches of water pressure drop to the system and additional electrical load requirements.

Environmental Impacts

There are no negative environmental impacts from the usage of new LNBs/particulate matter burners, switching to low-sulfur diesel fuel, or using a fabric filter.

Economic Impacts

A summary of the costs and particulate matter removed for the alternatives is recorded in Table 6.

Table 10.6 – Particulate Matter Control Cost Comparison*			
Factor	**Fabric Filter**	**Switch to PNG**	**Switch to Low-Sulfur Fuel**
Total installed capital costs	$20,000,000[a]	$0	$1,000,000[b]
Total first year fixed and variable O&M costs	$253,592	--	--
Total first year annualized cost	$3,615,938	--	--
Power consumption (MW)	0.40	--	--

Table 10.6 – Particulate Matter Control Cost Comparison*			
Factor	**Fabric Filter**	**Switch to PNG**	**Switch to Low-Sulfur Fuel**
Annual power usage (Million kW-hr/year)	1.4	--	--
Particulate matter design control efficiency	79.6%	--	--
Tons particulate matter removed per year	116	--	--
First year average control cost ($/ton particulate matter removed)	$24,916	--	--
Incremental control cost ($/ton particulate matter removed)	$31,284	--	--

* LNB costs included in NOx BART analysis
[a] Based on vendor cost information
[b] From CH2M HILL database

Step 6: Evaluate Visibility Impacts

Improvements in visibility due to PM_{10} controls are minimal relative to uncontrolled emissions while combusting No. 6 fuel oil. In addition, the incremental costs related to adding a fabric filter and SDA are high. Impacts from the combustion of No. 2 fuel oil or natural gas without PM_{10} controls are expected to be less than those from the combustion of No. 6 fuel oil with emission controls.

Step 7: BART Determination

After reviewing the company's BART analysis, and based upon the information above ADEQ has determined that, for Unit 1, BART for PM_{10} is the use of PNG with a PM_{10} emissions limit of 0.0075 lb/MMBtu. Fuel oil will no longer be an authorized fuel for Unit 1. The PM_{10} emissions will be measured by conducting EPA method 201/202 tests.

D.3 SO_2 BART Analysis

SO_2 forms in the boiler during the combustion process and is primarily dependent on natural gas and fuel oil sulfur content. Emissions indicate that BART analysis is not required when ST1 burns PNG or fuel oil No. 2. Thus, the analysis in this section is limited to the case when ST1 is burning No. 6 fuel oil.

The EPA BART guidelines require that oil-fired units consider limiting the sulfur content of the fuel oil burned. Because current requirements for low-sulfur diesel fuel limit sulfur content to 0.05 percent, fuel switching will be analyzed as an SO_2 option for this study. Also, a dry FGD system with SO_2 reduction capability similar to the fuel switch option will be considered.

Step 1: Identify the Existing Control Technologies in Use at the Source

There is no SO_2 emissions control equipment installed on ST1.
Step 2: Identify All Available Retrofit Control Options

A broad range of information sources was reviewed in an effort to identify potentially applicable emission control technologies for SO_2 at ST1, including control technologies identified as BACT or LAER by permitting agencies across the United States.

Following elimination of the PNG and fuel oil No. 2 BART engineering analysis after RLBC database review, the following potential SO_2 control technology options were considered for application when ST1 burns fuel oil No. 6:

- Use of low-sulfur distillate oil (No. 2 fuel oil)
- Switch to PNG
- SDA

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ determined that all of the identified control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Table 10.7 lists the various control technologies and estimated emissions rates.

Table 10.7 – Control Technology Options Evaluated

Technology	**Expected Emission Rate (lb/MMBtu)**	**Estimated Cost (Millions $)**
Current Baseline with No. 6 Fuel Oil	0.906	--
Low-Sulfur Fuel Oil	0.051	0
SDA	0.10	20
PNG	0.00064	0

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts

There is no energy impact associated with switching to low-sulfur diesel fuel; however, additional system pressure drop equivalent to 0.4 MW at a first-year cost of $71,832 will result from the installation of an SDA.

Environmental Impacts

There is no environmental impact associated with switching to low-sulfur diesel fuel. An SDA system generates solid waste requiring disposal.
Economic Impacts

A summary of the costs and amount of SO_2 removed for fuel switching is provided in Table 10.8. The complete Economic Analysis is contained in Appendix A of the AEPCO BART submittal.

Table 10.8 – SO_2 Control Costs			
Factor	**SDA**	**Switch to PNG**	**Switch to Low-Sulfur Fuel**
Total installed capital costs	$20,000,000[a]	$0	$0
Total first year fixed and variable O&M costs	$519,359	--	--
Total first year annualized cost	$3,811,706	--	--
Power consumption (MW)	0.40	--	--
Annual power usage (Million kW-hr/year)	1.4	--	--
SO_2 design control efficiency	89.0%	99.9%	91%
Tons SO_2 removed per year	1,587	--	--
First year average control cost ($/ton SO_2 removed)	2,446	--	--
Incremental control cost ($/ton SO_2 removed)	2,446	--	--

[a] Based on vendor cost information

Step 6: Evaluate Visibility Impacts

Improvements to deciview impacts from SO_2 controls are minimal relative to uncontrolled emissions while combusting No. 6 fuel oil. In addition, the incremental costs related to adding a fabric filter and SDA are high. Impacts from the combustion of No. 2 fuel oil or natural gas without SO_2 controls are expected to be less than those from the combustion of No. 6 fuel oil with emission controls.

Step 7: BART Determination

After reviewing the company's BART analysis and based upon the information above, ADEQ has determined that, for Unit 1, BART for SO_2 is the use of PNG with an SO2 emissions limit of 0.00064 lb/MMBtu. The limit would apply on a 30-day rolling average basis.

E. Steam Units 2 and 3

Steam Units 2 and 3 are substantially similar in design, construction and electrical output. While there are physical differences between the two units that will result in different costs for the same control technology, the overall differences were determined to be minimal. As a result, ADEQ has determined that it is appropriate to consider BART for both Units in a single section.

E.1 NO_X BART Analysis

During coal combustion, NO_X forms in three ways. The dominant source of NO_X formation is the oxidation of fuel-bound nitrogen (fuel NO_X). During combustion, part of the fuel NO_X is released from the coal with the volatile matter, and part is retained in the solid portion (char). The nitrogen chemically bound in the coal is partially oxidized to nitrogen oxides (NO and NO_2) and partially reduced to molecular nitrogen (N_2). A smaller part of NO_X formation is due to high temperature fixation of atmospheric nitrogen in the combustion air (thermal NO_X). A very small amount of NO_X is called "prompt" NO_X. Prompt NO_X results from an interaction of hydrocarbon radicals, nitrogen, and oxygen.

Step 1: Identify the Existing Control Technologies in Use at the Source

Both Steam Units 2 and 3 currently use over-fired air (OFA) and under-fired air systems to control NO_X emissions.

Step 2: Identify All Available Retrofit Control Options

The second step of the BART process is to evaluate NO_X control technologies with practical potential for application to Units 2 and 3, including those control technologies identified as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) by permitting agencies across the United States. Both Steam Unit 2 and 3 NO_X emissions are currently controlled through the use of OFA and UFA systems added to the burners. The Units are dry turbo-fired boilers, with 12 Riley directional flame burners. The following potential NO_X control technology options were considered:

- New/modified state-of-the-art LNBs with advanced OFA
- Rotating opposed fire air (ROFA)
- Selective non-catalytic reduction system (Rotamix and SNCR)
- Selective catalytic reduction (SCR) system
- Neural Network Controls/Boiler Combustion Controls (Neural Net)

New LNBs with OFA System. The mechanism used to lower NO_X with LNBs is to stage the combustion process and provide a fuel-rich condition initially; this is so oxygen needed for combustion is not diverted to combine with nitrogen and form NO_X. Fuel-rich conditions favor the conversion of fuel bound nitrogen to N_2 instead of NO_X. Additional air (OFA or UFA) is then introduced upstream or downstream in a lower temperature zone to burn out the char.

ROFA. Mobotec markets ROFA as an improved second generation OFA system. Mobotec states that "the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles." Rotation is reported to prevent laminar flow and improve gas mixing, so that the entire volume of the furnace can be used more effectively for the combustion process. In addition, the swirling action reduces the maximum temperature of the flames and increases heat absorption. Mobotec expects that enhanced mixing will also result in reduction in hot and cold furnace zones, improved heat absorption and boiler efficiency, and lower carbon monoxide (CO) and NO_X emissions. A typical ROFA installation will have a booster fan(s) to supply the high-velocity air to the ROFA boxes. Mobotec proposed one 2,100 horsepower fan for each unit, which would provide hot air at all boiler loads.

SNCR. With SNCR, an amine-based reagent such as ammonia—or more commonly urea—is injected into the furnace within a temperature range of 1,600 degrees Fahrenheit (°F) to 2,100 °F, where it reduces

NO_X to nitrogen and water. NO_X reductions of up to 40 to 60 percent have been achieved, although 15 to 30 percent is a more realistic expectation for most applications.

Reagent utilization, which is a measure of the efficiency with which the reagent reduces NO_X, can range from 20 to 60 percent, depending on the amount of reduction, unit size, operating conditions, and allowable ammonia slip. With low reagent utilization, low temperatures, or inadequate mixing, ammonia slip occurs, allowing unreacted ammonia to create problems downstream. Problems include rendering fly ash unsellable, and also reacting with sulfur to form ammonium bisulphate, which can foul heat exchanger surfaces or create a visible stack plume. Reagent utilization can have a significant impact on economics, with higher levels of NO_X reduction generally resulting in higher reagent utilization and higher operating cost. Reductions from higher baseline inlet NO_X concentrations are lower in cost per ton, but result in higher operating costs, due to greater reagent consumption.

SCR. SCR works on the same chemical principle as SNCR but instead uses a catalyst to promote the chemical reaction. Ammonia or urea is injected into the flue-gas stream, where it reduces NO_X to nitrogen and water. Unlike the high temperatures required for SNCR, in SCR the reaction takes place on the surface of a vanadium/titanium-based catalyst at a temperature range between 580° F to 750° F. Due to the catalyst, the SCR process is more efficient than SNCR and results in lower NO_X emissions. One type of SCR is the high-dust configuration, where the catalyst is located downstream from the boiler economizer and upstream of the air heater and any particulate control equipment. In this location, the SCR is exposed to the full concentration of fly ash in the flue gas that is leaving the boiler. However, for Units 2 and 3 the SCR could be installed after the hot-side ESP and before the air heater. In a full-scale SCR, the flue ducts are routed to a separate large reactor containing the catalyst. With in-duct SCR, the catalyst is located in the existing gas duct, which may be expanded in the area of the catalyst to reduce flue gas flow velocity and increase flue gas residence time. Due to the higher NO_X removal rate, a full-scale SCR was used as the basis for analysis at Units 2 and 3.

Neural Net Controls/Boiler Combustion Control. Review of neural net and improved boiler combustion control are combined for purposes of this analysis under the potential implementation of neural net boiler control system. Information regarding neural net controls was provided by NeuCo, Inc. While NeuCo offers several neural net products, CombustionOpt and SootOpt provide the potential for NO_X reduction. NeuCo stated these products can be used on most control systems, and can be effective even in conjunction with other NO_X reduction technologies. NeuCo predicts that CombustionOpt can reduce NO_X by 15 percent, and SootOpt can provide an additional 5 to 10 percent. Because NeuCo does not offer guarantees on this projected emission reduction, a nominal reduction of 15 percent was assumed for evaluation purposes.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the identified control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Table 10.9 lists the various control technologies and estimated emissions rates.

Table 10.9 – Control Technology and Respective Emission Rates	
Control Technology	**Expected NO_X Emission Rate**
Neural Net/Boiler Combustion Control	15% reduction
New LNBs with OFA System	0.31 lb/MMBtu
ROFA	0.26 lb/MMBtu
SNCR	0.18 lb/MMBtu
SCR	0.07 lb/MMBtu

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step involves the consideration of energy, non-air quality environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts

Installation of LNBs and modification to the existing OFA and UFA systems are not expected to significantly impact the boiler efficiency or forced-draft fan power usage. Therefore, these technologies are not expected to have significant energy impacts.

The Mobotec ROFA system requires installation and operation of one 2,100 horsepower ROFA fan (1,566 kilowatts [kW] total) for each unit. Fuel Tech provided an estimate of 130 kW of additional auxiliary power, and the same estimate was used for Rotamix. SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase.

Non-Air Quality Environmental Impacts

Mobotec generally predicts that CO emissions, and unburned carbon in the ash, commonly referred to as loss on ignition (LOI), would be the same or lower than prior levels for the ROFA system.

SNCR and SCR installation could impact the salability and disposal of fly ash due to ammonia levels. Other environmental impacts involve the potential public and employee safety hazard associated with the storage of ammonia, especially anhydrous ammonia, and the transportation of the ammonia to the power plant site.

Economic Impacts

A comparison of the technologies on the basis of costs, design control efficiencies, and tons of NO_X removed is summarized in Table 10.10 for Unit 2 and Table 10.11 for Unit 3. The complete Economic Analysis is contained in Appendix A of the AEPCO BART submittal.

Table 10.10 – Control Technology Efficiency and Costs for Unit 2					
Factor	**LNB with OFA**	**ROFA**	**ROFA with Rotamix**	**LNB with OFA and SNCR**	**LNB with OFA and SCR**
Major Materials Design Costs (Million $)	$2.000	$3.627	$5.441	$6.830	$29.30
Total Installed Capital Costs (Million $)	$4.760	$9.616	$12.63	$12.54	$48.74
Total First Year Fixed and Variable Costs (Million $)	$0.080	$0.750	$1.024	$0.545	$1.466
Total First Year Annualized Cost (Million $)	$0.533	$1.664	$2.225	$1.738	$6.102
Power Consumption (MW)	-	1.57	2.07	0.50	1.00
Annual Power Usage (Kilowatt-Hr/Year)	-	12.6	16.6	4.0	8.0
NO_X Design Control Efficiency	34.2%	44.8%	61.8%	51.2%	85.1%
Tons of NO_X Removed	1,305	1,710	2,358	1,953	3,250
Average Cost ($/ton)	$408	$973	$944	$890	$1,878
Incremental Cost ($/ton)	$408	$2,793	$1,203	$301	$4,350

Table 10.11: Control Technology Efficiency and Costs for Unit 3					
Factor	**LNB with OFA**	**ROFA**	**ROFA with Rotamix**	**LNB with OFA and SNCR**	**LNB with OFA and SCR**
Major Materials Design Costs (Million $)	$2.000	$3.627	$5.441	$6.830	$29.30
Total Installed Capital Costs (Million $)	$4.760	$9.616	$12.62	$12.54	$48.74
Total First Year Fixed and Variable Costs (Million $)	$0.080	$0.719	$0.981	$0.525	$1.426
Total First Year Annualized Cost (Million $)	$0.533	$1.634	$2.182	$1.718	$6.062
Power Consumption (MW)	-	1.57	2.07	0.50	1.00
Annual Power Usage (Kilowatt-Hr/Year)	-	12.0	15.8	3.8	7.7
NO_X Design Control Efficiency	27.9%	39.5%	58.1%	46.5%	83.7%
Tons of NO_X Removed	926	1,312	1,929	1,543	2,778
Average Cost ($/ton)	$575	$1,246	$1,131	$1,113	$2,183
Incremental Cost ($/ton)	$575	$2,855	$1,203	$360	$4,572

Step 6: Evaluate Visibility Impacts

Tables 10.12 and 10.13 below show the total deciview reduction for the most impacted Class I area for Units 2 and 3 respectively. For Units 2 and 3, the most impacted Class I area is the Chiricahua Wilderness Area and National Monument.

Table 10.12 – Control Technology and Visibility Impact Reduction for Unit 2

Control	Deciview Reduction	Total Annualized Cost (Million $)	Cost per deciview reduced (Million $/dv)	Average Cost ($/ton)
Neural Net/Boiler Combustion Control	Unknown	Unknown	Unknown	Unknown
New LNB with OFA System	0.267	$0.533	$1.996	$408
ROFA	0.359	$1.664	$4.636	$973
ROFA with Rotamix	0.491	$2.225	$4.532	$944
LNB with OFA and SNCR	0.416	$1.738	$4.177	$890
LNB with OFA and SCR	0.676	$6.103	$9.028	$1,878

Table 10.13 – Control Technology and Visibility Impact Reduction for Unit 3

Control	Deciview Reduction	Total Annualized Cost (Million $)	Cost per Deciview Reduced (Million $/dv)	Average Cost ($/ton)
Neural Net/Boiler Combustion Control	Unknown	Unknown	Unknown	Unknown
New LNB with OFA System	0.206	$0.533	$2.586	$575
ROFA	0.298	$1.634	$5.484	$1,246
ROFA with Rotamix	0.436	$2.182	$5.004	$1,131
LNB with OFA and SNCR	0.356	$1.718	$4.825	$1,113
LNB with OFA and SCR	0.633	$6.062	$9.577	$2,183

Step 7: BART Selection

After reviewing the company's BART analysis, and based upon the information above, ADEQ has determined that, for Units 2 and 3 BART for NO_X is new LNBs with the existing OFA system with a NO_X emissions limit of 0.31 lb/MMBtu for both Units 2 and 3 on a 30-day rolling average basis.

E.2 PM_{10} BART Analysis

Step 1: Identify the Existing Control Technologies in Use at the Source

Both Steam Units 2 and 3 are currently equipped with hot-side Electrostatic Precipitators (ESPs).

Step 2: Identify All Available Retrofit Control Options

Steam Units 2 and 3 are currently equipped with hot-side ESPs. Historically, outlet ESP particulate emissions on Units 2 and 3 have ranged from approximately 0.007 to 0.045 lb/MMBtu. This wide range in outlet emissions can in part be attributed to the hot-side operation, as well as the wide variety of coals being burned in the boilers. Hot-side ESP effectiveness may also be impacted by sodium content in the ash.

Three retrofit control technologies have been identified for additional particulate matter control:

- Performance upgrades to existing hot-side ESP
- Replace current ESP with a fabric filter unit
- Install a polishing fabric filter after ESP

Performance Upgrades. Modifications to the hot-side ESPs, such as improving the rapping system, controller upgrades, conversion to cold-side operation, flue gas conditioning, wide plate spacing, addition of particle pre-charging system, etc., could be implemented to improve ESP particulate collection efficiency.

Replace Current ESP with a Fabric Filter Unit. Full-size pulse jet fabric filters could be installed as a replacement for the existing ESPs on Units 2 and 3. These fabric filters would be sized for approximately 3.5 or 4:1 Air to Cloth (A/C) ratio (actual cubic feet per minute of flue gas per square foot of fabric). An A/C ratio of 4:1 was used for this analysis. Fabric filters have been proven to provide highly effective and consistent particulate emissions reduction, with outlet emissions of approximately 0.015 lb/MMBtu. The ESPs would be removed from service with these replacement fabric filters.

Install a Polishing Fabric Filter. A polishing fabric filter could be added downstream of the existing ESPs on Units 2 and 3. One such technology is licensed by the Electric Power Research Institute, and referred to as a COHPAC (Compact Hybrid Particulate Collector). The COHPAC collects the ash that is not collected by the ESP, thus acting as a polishing device. The ESPs would be kept in service for the COHPAC fabric filter to operate effectively.

The COHPAC fabric filter is about one-half to two-thirds the size of a full-size fabric filter. Because the COHPAC has a higher A/C ratio (as high as 6 to 8:1), compared to a full-size pulse jet fabric filter (3.5 to 4:1), an A/C ratio of 6:1 was used for this analysis.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the identified control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Table 10.14 lists the various control technologies and estimated emissions rates.

Table 10.14 – Control Technology and Respective Emission Rates	
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

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step involves the consideration of energy, non-air quality environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts

Energy is required to overcome the additional pressure drop from both the fabric filter replacement and COHPAC fabric filter, and associated ductwork. Therefore, fan upgrades may be required for both alternatives to overcome the additional pressure drop. An estimated 6 to 8 inches of water pressure drop for the replacement fabric filter may be experienced, with 8 to 10 inches of water pressure drop likely for the COHPAC unit. The polishing fabric filter will also result in maintaining the existing ESP in service, which will result in power consumption in addition to what is required by the fabric filter replacement option.

COHPAC fabric filters on Units 2 and 3 would require approximately 1.3 MW of power each.

Energy impacts from ESP upgrades are unknown and would vary depending on the precipitator upgrade applied.

Non-Air Quality Environmental Impacts

There are no negative environmental impacts from precipitator upgrades, the addition of a replacement or COHPAC polishing fabric filter.

Economic Impacts

A comparison of the costs and PM_{10} removed for a replacement fabric filter or COHPAC polishing fabric filter are shown in Table 10.15 and 10.16 for Units 2 and 3 respectively. Specific costs for the precipitator upgrades were not evaluated as AEPCO has yet to evaluate the upgrades that may be applicable to Units 2 and 3. Capital cost information was provided by Alstom for both the polishing and replacement fabric filters. The complete Economic Analysis is contained in Appendix A of the AEPCO BART submittal.

Table 10.15 – Control Technology Efficiency and Costs for Unit 2			
Factor	**ESP Upgrades**	**Polishing Fabric Filter**	**Full Size Fabric Filter**
Major Materials Design Costs	Unknown	$6,666,667	$10,000,000
Total Installed Capital Costs	Unknown	$15,866,667	$23,800,000
Total First Year Fixed and Variable Costs	Unknown	$708,050	$623,824
Total First Year Annualized Cost	Unknown	$2,217,411	$2,887,867
Power Consumption (MW)	Unknown	1.30	1.00
Annual Power Usage (Kilowatt-Hr/Year)	Unknown	10.5	8.0
PM_{10} Design Control Efficiency	Unknown	66.67%	66.67%
Tons of PM_{10} Removed	Unknown	243	243
Average Cost ($/ton)	Unknown	$9,121	$11,878
Incremental Cost ($/ton)	Unknown	$9,121	$11,878

Table 10.16 – Control Technology Efficiency and Costs for Unit 3			
Factor	**ESP Upgrades**	**Polishing Fabric Filter**	**Full Size Fabric Filter**
Major Materials Design Costs	Unknown	$6,666,667	$10,000,000
Total Installed Capital Costs	Unknown	$15,866,667	$23,800,000
Total First Year Fixed and Variable Costs	Unknown	$682,996	$604,552
Total First Year Annualized Cost	Unknown	$2,192,357	$2,868,595
Power Consumption (MW)	Unknown	1.30	1.00
Annual Power Usage (Kilowatt-Hr/Year)	Unknown	10.0	7.7
PM_{10} Design Control Efficiency	Unknown	66.67%	66.67%
Tons of PM_{10} Removed	Unknown	231	231
Average Cost ($/ton)	Unknown	$9,471	$12,393
Incremental Cost ($/ton)	Unknown	$9,471	$12,393

Step 6: Evaluate Visibility Impacts

Tables 10.17 and 10.18 below show the total deciview reduction for the most impacted Class I area for Units 2 and 3 respectively. For Units 2 and 3, the most impacted Class I area is the Chiricahua Wilderness Area and National Monument.

Table 10.17 – Control Technology and Visibility Impact Reduction for Unit 2				
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 10.18 – Control Technology and Visibility Impact Reduction for Unit 3				
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

Step 7: BART Selection

Based upon its review of the analysis provided by AEPCO, and the information provided above, ADEQ has determined that BART for PM_{10} emissions is upgrades to the existing ESP and a PM_{10} emissions limit of 0.03 lb/MMBtu for both Units 2 and 3. The upgrades to the existing ESP will involve a possible installation of a flue gas conditioning system, improvements to the scrubber bypass damper system, and implementing programming optimization measures for ESP automatic voltage controls. The PM_{10} emissions will be measured by conducting EPA Method 201/202 tests.

D.3 SO_2 BART Analysis

SO_2 forms in the boiler during the combustion process from the oxidation of the sulfur present in the coal, and is primarily dependent on coal sulfur content. The BART analysis for SO_2 emissions on Units 2 and 3 is described below.

Step 1: Identify the Existing Control Technologies in Use at the Source

Steam Units 2 and 3 currently have wet limestone scrubbers installed for SO_2 removal.

Step 2
: Identify All Available Retrofit Control Options

The following potential SO_2 control technology option was considered:

- Enhancement of current wet limestone scrubber or SDAS

Units 2 and 3 currently operate wet limestone scrubbers for SO_2 removal, with current emissions of 0.184 lb/MMBtu and 0.151 lb/MMBtu respectively. The EPA BART guidelines state that for existing units with SO_2 controls achieving at least 50 percent SO_2 removal, cost-effective scrubber upgrades should be considered. EPA has recommended consideration of the following potential upgrades:

- Elimination of bypass reheat
- Installation of liquid distribution rings
- Installation of perforated trays
- Use of organic acid additives
- Improve or upgrade scrubber auxiliary system equipment
- Redesign spray header or nozzle

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the identified control technology upgrades are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

When evaluating the control effectiveness of SO_2 reduction technologies, each option can be compared against benchmarks of performance. In its BART analysis, AEPCO chose to compare its proposed technology upgrades to EPA's presumptive BART emission limitations. According to EPA's BART guidance documents, the presumptive limit for SO_2 on a BART-eligible coal-burning unit, used here as a point of reference, is 95 percent removal, or 0.15 lb/MMBtu.

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Over the past several years AEPCO has completed several scrubber upgrades to improve performance, including the following:

- Elimination of flue gas bypass
- Splitting the limestone feed to both 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
- Replacement of scrubber packing with perforated stainless steel trays

Dibasic acid additive was tested; however results did not show significantly higher SO_2 removal.

Energy Impacts

Upgraded operation of the existing wet limestone scrubber or SDAS system is not expected to result in any additional power consumption.

Environmental Impacts

There will be incremental additions to scrubber waste disposal and makeup water requirements and a reduction of the stack gas temperature if there is elimination of flue gas bypass.

Economic Impacts

There are no anticipated cost impacts attributable to upgraded scrubber operation.

Step 6: Evaluate Visibility Impacts

A Visibility Impact Analysis was not performed for SO_2 since the existing scrubbers are proposed as BART.

Step 7: BART Selection

After reviewing the company's BART analysis, and based upon the information above, ADEQ has determined that BART for SO_2 emissions is no new controls and an emission limit of 0.15 lb/MMBtu on a 30-day rolling average basis.

XI. APS CHOLLA GENERATING STATION BART ANALYSIS AND DETERMINATION

A. Process Description

The APS Cholla Power Plant ("APS Cholla") consists of the following four electric generating units with a total generating capacity of 1,150 megawatts (MW).

- Unit 1: 125 MW
- Unit 2: 300 MW
- Unit 3: 300 MW
- Unit 4: 425 MW

Each unit is a coal-fired steam generating unit equipped with a tangentially-fired, dry-bottom boiler. Each of these Units burns bituminous or sub-bituminous coal to generate super-heated steam. This steam is then used to drive turbines/generators for producing electricity. Cholla purchases coal from the Lee Ranch and El Segundo mines.

B. Description of Emissions Units Subject to Best Available Retrofit Technology (BART)

Units 2, 3 and 4 are potentially subject-to-BART because:

1. These units belong to one of the 26 categorical sources;
2. These units were in existence on August 7, 1977;
3. Combined emissions of visibility impairing pollutants from all three of these Units - nitrogen oxides (NO_X), particulate matter less than 10 microns (PM_{10}), and sulfur dioxide (SO_2) - are greater than 250 tons per year for each pollutant.

C. Impact on Visibility

CALPUFF modeling was performed at 13 Class I areas that are located within 300 kilometers of Cholla Power Plant. The following table provides the baseline maximum impact on visibility in deciview.

Table 11.1 – Modeled Baseline Impact on Visibility

Affected Class I Area	Unit 2	Unit 3	Unit 4
Capital Reef NP	1.25	2.70	2.40
Grand Canyon NP	1.45	2.45	2.65
Petrified Forest NP	1.40	3.00	3.40
Sycamore Canyon WA	1.62	2.50	2.70
Gila WA	0.68	2.10	2.20
Mount Baldy WA	1.12	2.25	2.25
Sierra Ancha WA	0.91	1.90	2.15
Mazatzal WA	1.02	1.72	1.85

Table 11.1 – Modeled Baseline Impact on Visibility			
Affected Class I Area	**Unit 2**	**Unit 3**	**Unit 4**
Pine Mountain WA	1.20	1.75	1.88
Superstition WA	0.95	1.95	2.15
Galiuro WA	0.57	1.18	1.28
Mesa Verde NP	0.81	1.45	1.40
Saguaro NP	0.43	0.95	1.15

D. Nitrogen Oxides (NO_x) BART Analysis and Determination for Units 2, 3 and 4

Step 1: Identify the Existing Control Technologies in Use at the Source

The Cholla BART Analysis was completed in late 2007. At that time, the Units were equipped with Close-coupled Overfire Air (COFA). Overfire air is used to reduce NO_X by reducing excess air in the combustion zone. In a COFA system, air nozzles are immediately above the burners.

Low NO_X Burner (LNBs) and Seperated Overfire Air (SOFA) were installed on Units 2, 3 and 4 in March 2008, May 2009 and May 2008 respectively. LNBs and SOFAs are utilized for increased NO_X reduction.

Step 2: Identify All Available Retrofit Control Options

APS Cholla has identified the following available retrofit control technologies for NO_X control in Units 2, 3 and 4.

- LNB with Separate Overfire Air (SOFA) System
- LNB with SOFA and Selective Non-Catalytic Reduction (SNCR) System
- Rotating Opposed Flow Air system (ROFAs)
- ROFA with Rotary Mixing of Additives (Rotamix)
- LNB with SOFA and Selective Catalytic Reduction (SCR)

LNB with Separate Overfire Air (SOFA) System. Initial combustion takes place in fuel-rich condition so that the oxygen needed for combustion is not diverted to form NO_X. Additional air (separate overfire air) is then introduced in a lower temperature zone to burn out the char.

LNB with SOFA and Selective Non-Catalytic Reduction (SNCR) System. SNCR systems reduce NO_x by injecting reagent (ammonia or urea) into the furnace within a temperature range of 1600º to 2100º F. NO_X reduction of 40% to 60% can be achieved. Reagent utilization is a measure of efficiency with which the reagent reduces NO_X. Ammonia slip may occur due to lower temperatures, or inadequate mixing causing problems downstream. Potential problems include: rendering fly ash unsalable and reacting with sulfur to form ammonium bisulphate which can foul exchangers. The combination of LNB and SOFA with SNCR may achieve lower emission reductions than can be achieved by the individual technologies alone.

Rotating Opposed Flow Air System (ROFA). ROFA is an improved overfire air system. In this technology, the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles. This rotation prevents laminar flow and improves gas mixing. As a result, the entire volume of the furnace is used more effectively for combustion process. A typical ROFA system requires a booster fan to supply high velocity air to the ROFA boxes.

ROFA with Rotary Mixing of Additives (Rotamix). ROFA along with Rotamix system provides enhanced mixing in the combustion chamber for optimal conditions to achieve multi-pollutant reduction. The turbulent mixing created by ROFA and Rotamix improves the efficiency of pollutant capture and reduces the stoichiometric amount of sorbent needed to reduce pollutants emissions.

LNB with SOFA and Selective Catalytic Reduction (CR). In SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent, achieving NO_X emission reductions when the gas stream is passed over a vanadium/titanium-based catalyst. The NO_X and ammonia react to form nitrogen and water vapor. The SCR ammonia-catalytic reaction requires a temperature range of 580-750° F.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the options identified above are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

The following table provides the NO_X emission rates that will be achieved with different feasible NO_X control technologies for Units 2, 3 and 4.

Table 11.2 – Achievable NO_X Emissions Rates By Technology

Control Technology	NO_X Emissions		
	Unit 2	Unit 3	Unit 4
	Pounds per MMBtu	Pounds per MMBtu	Pounds per MMBtu
LNB with COFA (Baseline)	0.50	0.410	0.415
LNB with SOFA	0.22	0.22	0.22
LNB with SOFA and SNCR	0.17	0.17	0.17
ROFA	0.16	0.16	0.16
ROFA with Rotamix	0.12	0.12	0.12
LNB with SOFA and SCR	0.07	0.07	0.07

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Economic Impacts

The following Tables 3, 4 and 5 present the cost of compliance for the feasible technologies for Units 2, 3 and 4. The tables also report the predicted impact of these technologies on visibility [98th percentile deciview (dv)] reduction.

Energy Impacts

ROFA system will require a 3,300 HP fan for the supply of high-velocity air. Thus, there will be an additional power requirement of 130 KW.

SCR retrofit will cause additional pressure drop (6-8 inches water gauge) in the flue gas system due to catalyst.

LNBs and SOFA systems do not significantly impact boiler efficiency or power usage.

Non-Air Quality Environmental Impacts

SNCR and SCR installations could impact the salability and disposal of fly ash due to ammonia levels. At this time, APS Cholla sells its fly ash, and if sellability of the fly ash is impacted, costs associated with the proposed controls will increase. SCR and SNCR may also involve potential safety hazard associated with handling of anhydrous ammonia, and transportation of ammonia to the plant site.

Remaining Useful Life

Units 2, 3 and 4 have projected remaining lives of 40 years at each unit.

Step 6: Evaluate Visibility Impacts

CALPUFF modeling was performed at 13 Class I areas that are located within 300 kilometers of Cholla Power Plant the degree of that may be reasonably expected from the use of BART. The impacts are modeled for different NO_X control scenarios, combined with SO_2 and PM_{10} technologies. Since, as shown in Table 11.1, the Petrified Forest National Park is the most impacted area out of all the 13 Class I areas, Tables 11.3, 11.4 and 11.55 present the improvement in visibility (in deciview) in that area.

Table 11.3: Unit 2 Cost and Visibility Analysis

NO_X Control Technologies	Emission Rate	NO_X Removal	Annualized Cost	1st yr Avg. Cost	Incremental Control Cost	Dv Impact for Max. Impacted Area (Petrified Forest NP)	
	lb/MMBtu	Tons/year	Million $	$/ton	$/ton	98th percentile dv reduction	million $/dv reduced
LNB with COFA (Baseline)	0.503	-	-	-	-	-	-
LNB with SOFA	0.22	3,314	$0.635	$192	$192	0.187	$3.40
LNB with SOFA and SNCR	0.17	3,900	$2.175	$558	$2,628	0.218	$9.98
ROFA	0.16	4,017	$2.297	$572	$1,043	0.232	$9.90
ROFA with Rotamix	0.12	4,485	$3.384	$755	$2,323	0.261	$12.97
LNB with SOFA and SCR	0.07	5,071	$9.625	$1,898	$10,650	0.287	$33.54

Table 11.4 – Unit 3 Cost and Visibility Analysis

NO_X Control Technologies	Emission Rate	NO_X Removal	Annualized Cost	1st yr Avg. Cost	Incremental Control Cost	Dv Impact for Max. Impacted Area (Petrified Forest NP)	
	lb/MMBtu	Tons/year	Million $	$/ton	$/ton	98th percentile dv reduction	million $/dv reduced
LNB with COFA (Baseline)	0.41	-	-	-	-	-	-
LNB with SOFA	0.22	2,096	$0.635	$303	$303	0.126	$5.04
LNB with SOFA and SNCR	0.17	2,648	$2.157	$814	$2,756	0.164	$13.15
ROFA	0.16	2,758	$2.243	$813	$786	0.169	$13.27
ROFA with Rotamix	0.12	3,200	$3.308	$1,034	$2,409	0.198	$16.71
LNB with SOFA and SCR	0.07	3,751	$9.569	$2,551	$11,363	0.230	$41.61

Table 11.5 – Unit 4 Cost and Visibility Analysis							
NO_X Control Technologies	Emission Rate	NO_X Removal	Annualized Cost	1st yr Avg. Cost	Incremental Control Cost	Dv Impact for Max. Impacted Area (Petrified Forest NP)	
	lb/MMBtu	tons/year	Million $	$/ton	$/ton	98th percentile dv reduction	million $/dv reduced
LNB with COFA (Baseline)	0.42	-	-	-	-	-	-
LNB with SOFA	0.22	3,390	$0.820	$242	$242	0.207	$3.96
LNB with SOFA and SNCR	0.17	4,259	$2.852	$670	$2,338	0.265	$10.76
ROFA	0.16	4,433	$3.179	$717	$1,877	0.281	$11.31
ROFA with Rotamix	0.12	5,129	$4.537	$885	$1,951	0.336	$13.50
LNB with SOFA and SCR	0.07	5,998	$13.23	$2,206	$10,007	0.408	$32.43

Step 7: BART Selection

According to the Regional Haze Rule, only dV changes in excess of 1.0 dV are perceptible.

A review of the data presented in Tables 11.3, 11.4, and 11.5 indicates that CALPUFF model-predicted visibility improvements (delta dV) for all five NO_x control scenarios are less than 0.5 dV. For example, in the case of Unit 3, the dV changes range from 0.126 dV for the LNB with SOFA (Scenario 1) to 0.230 dV for LNB with SOFA and SCR (Scenario 5). The change in dV between the least expensive and most expensive NO_x control technologies (the two noted above) is only 0.104 dV. The corresponding capital costs are $5.4 million for LNB/SOFA and $82.8 million for LNB/SOFA with SCR.

Based on these facts and the five-factor analysis discussed above, ADEQ has concluded that LNB with SOFA constitute BART for NO_x emissions for Cholla Units 2, 3, and 4. The BART limit will be 0.22 lb/MMBtu on a 30-day rolling average basis.

E. PM_{10} BART

Step 1: Identify the Existing Control Technologies in Use at the Source

Unit 2 currently has a mechanical dust collector for control of PM_{10} emissions. Additional particulate matter control is provided by a venturi scrubber. Cholla 2 is currently able to achieve emission rate of 0.020 lb/MMBtu.

Unit 3 was previously equipped with a hot-side ESP and was able to achieve an emission rate of 0.015 lb/MMBtu of PM_{10}. The facility completed installation of a fabric filter in May 2009. With the installation of the fabric filter, the facility expects to consistently achieve an emission rate of 0.015 lb/MMBtu for PM_{10}.

Unit 4 was previously equipped with a hot-side ESP and was able to achieve an emission rate of 0.024 lb/MMBtu of PM_{10}. The facility completed installation of a fabric filter in May 2008. With the installation of the fabric filter, the facility expects to consistently achieve an emission rate of 0.015 lb/MMBtu for PM_{10}.

Step 2: Identify All Available Retrofit Control Options

Since Units 3 and 4 will be equipped with fabric filters, and fabric filters are considered the top control technology for reducing PM emissions. As a result, no other technology is considered for these two Units. The following retrofit technologies are considered for Unit 2:

- Electrostatic Precipitators
- Fabric Filters

Electrostatic Precipitator. An ESP operates by placing a charge on the particles through electrodes, and then capturing the charged particles on collection plates.

Fabric Filter. The flue gas passes through the bags to remove particulate matter. The bags are cleaned by initiating a pulse of air into the top of the bag. The pulse causes a ripple effect along the length of the bag and releases the dust cake from the bag surface into a hopper.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that both fabric filters and electrostatic precipitators are technically feasible options.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Electrostatic Precipitator. ESPs are capable of achieving an emission rate of 0.015 lb/MMBtu. However, ESP operation is susceptible to particle resistivity. Particle resistivity is influenced by flue gas temperature. Thus, operational variations may not result in consistent compliance with the emission limit.

Fabric Filter. Fabric filters are proven to be highly effective and provide a consistent particulate matter reduction. The emissions at the outlet of fabric filter are expected to be less than 0.015 lb/MMBtu.

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Economic Impact

Since Units 3 and 4 are already equipped with bag filters, no economic impact analysis is required. For Unit 2, since the facility has already decided to install a new bag filter in 2015, this is the only option considered for the economic analysis.

Table 11.6 – Economic Impacts for Unit 2

Control	Emission Rate (lb/ MMbtu)	Total Emission (Tons/ Yr)	Total Emission Reduction (Tons)	Annualized Cost ($MM)	Cost/ Ton ($)	Incremental Cost/ton ($/ton)
Baseline (no control)	0.020	234	-	-	-	-
Fabric Filter	0.015	176	58	9.40	160,747	160,747

Energy Impacts

Since Units 3 and 4 are already equipped with bag filters, no energy impact analysis is required. For Unit 2, the installation of new fabric filter will result in additional pressure drop across the filter and associated duct work. Thus, additional power will be required. This is likely to be offset by the removal of mechanical dust collector and venturi scrubber.

Non-Air Quality Environmental Impacts

There are no negative environmental impacts from the installation of new fabric filter.

Step 6: Evaluate Visibility Impacts

The installation of a fabric filter is the only option considered for BART for all the 3 units.

Step 7: BART Selection

Based upon its review of the company's BART analysis and the information provided above, the Department has determined that, fabric filter with an associated emission limit of 0.015 lb/MMBtu is the BART for control of PM_{10} for Units 2, 3 and 4. The PM_{10} emissions will be measured by conducting EPA Method 201/202 tests.

It should be noted that the dollar per ton value of 160,747 for the installation of a fabric filter for Unit 2 would normally not be considered as a cost-effective number by the Department in a BART evaluation but is being chosen as BART because of the company's commitment to install the fabric filter by 2015.

F. Sulfur Dioxide (SO_2) BART

Step 1: Identify the Existing Control Technologies in Use at the Source

Unit 2. This unit is equipped with four venturi flooded disc scrubbers/absorber with lime reagent for SO_2 control. Currently, APS Cholla is able to achieve 0.14 lb/MMBtu to 0.25 lb/MMBtu of SO_2 on Unit 2.

Unit 3. This unit did not have any SO_2 control technology when the BART analysis was completed in late 2007. The facility installed a new wet lime scrubber in May 2009 to capture and treat all flue gases. This will result in Unit 3 consistently meeting an emission limit of 0.15 lb/MMBtu.

Unit 4. This Unit was previously operating with 36% flue gas scrubbing with emission rate of 0.734 lb/MMBtu. The facility installed a new wet lime scrubber in May 2008 to capture and treat all flue gases. This will result in Unit 4 consistently meeting an emission limit of 0.15 lb/MMBtu.

Step 2: Identify All Available Retrofit Control Options

Unit 2. The facility plans to remove the venturi section of the scrubber and considered a wet lime scrubber section for possible operational upgrades. Installation of bag filter as a part of BART will improve the performance of scrubber due to decreased plugging of scrubber. The facility expects to achieve 0.15 lb/MMBtu consistently with these operational upgrades.

Unit 3. In late 2007, APS Cholla identified the following available retrofit control technologies for SO_2 control in Unit 3:

- Dry Flue Gas Desulfurization (FGD) System
- Dry Sodium Sorbent Injection
- Wet Lime Scrubber

Dry Flue Gas Desulfurization (FGD) System. Dry FGD is based on the spray drying of lime slurry into flue gas. The SO_2 is absorbed into the fine spray droplets and reacts with the calcium to form dry calcium sulfite or sulfate. This is collected by the particulate control device along with fly ash.

Dry Sodium Sorbent Injection. Dry duct injection of sodium carbonate or sodium bicarbonate into the flue gas is utilized to remove SO_2. Unreacted/reacted sorbent is collected by the particulate control device along with fly ash.

Wet Lime Scrubber. SO_2 laden flue gas enters a scrubber where it is sprayed with lime slurry. The SO_2 reacts with the calcium to form calcium sulfite or sulfate which is removed and disposed off as scrubber waste, or reclaimed as gypsum.

Subsequently, Cholla intalled a new Wet Lime Scrubber on Unit 3 in May 2009. Therefore, the new wet lime scrubber, as described above, is the only retrofit control technology considered for this unit.
Unit 4. The wet lime scrubber, as described above, is the only retrofit control technology considered for this unit.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the control options identified above are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Dry FGD System. This technology is estimated to achieve 90% control efficiency. Thus the achievable emission rate with this technology is 0.25 lb/MMBtu.

Dry Sodium Sorbent Injection. Maximum SO_2 removal efficiency for this technology is 75%. Thus, for an initially uncontrolled emission rate of 2.5 pounds/MMBtu, the achievable emission rate with this technology is 0.625 lb/MMBtu.

Wet Lime Scrubber. Wet lime scrubbers are capable of very high SO_2 removal efficiency. Based on a 95% control efficiency, the wet lime scrubber can achieve the emission rate of 0.15 lb/MMBtu.

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Economic Impact

Unit 2. Only operational upgrades will be done on the existing wet lime scrubber. Hence there is no economic impact.

Unit 3. The installation of a new wet lime scrubber was completed in May 2009. This technology provides the maximum reduction in SO_2 emissions. The wet lime scrubber is the only option considered for economic analysis.

Table 11.7 – Economic Impacts for Unit 3

Control	Emission Rate (lb/ MMbtu)	Total Emission (Tons/ Yr)	Total Emission Reduction (Tons)	Annualized Cost (Million$)	Cost/ Ton ($)	Incremental Cost/ton ($/ton)
Baseline (no control)	1.00	11,033	-	-	-	-
Wet Lime scrubber	0.15	1,655	9,378	$8.80	936	$936

Unit 4. The facility has completed the installation of a new wet lime scrubber in May 2008. Thus, there is no economic impact that needs to be assessed.

Energy Impacts

There will be no energy impact for Units 2, 3, and 4 as these scrubbers are already in place.

Non-Air Quality Environmental Impacts

There will be no non-air quality environmental impact for Units 2, 3, and 4 as these scrubbers are already in place.

Step 6: Evaluate Visibility Impacts

Wet lime scrubber is the only option considered for BART for Units 2, 3 and 4.

Step 7: BART Selection

Based upon its review of the BART analysis provided by the company, and the information provided above, the Department has determined that wet lime scrubbers with an associated emission limit of 0.15 lb/MMBtu on a 30-day rolling average basis is the BART for control of SO_2 for Units 2, 3 and 4.

XIV. SRP CORONADO GENERATING STATION BART ANALYSIS AND DETERMINATION

A. Process Description

SRP Coronado Generating Station (CGS) is comprised of two coal-fired electric utility steam generating units, specifically Unit 1 and Unit 2. These are dry-turbo-fired boilers with a net rated output of 395 MW and 390 MW respectively. CGS generates electricity by combustion of pulverized coal that heats water in boiler tubes to produce steam. This steam is then used to turn a turbine which is connected on a common shaft to a generator rotor. As the rotor in the generator is turned, it induces an electrical current in the stator windings of the generator, making electricity.

B. Consent Decree

On December 22, 2008, SRP and EPA entered into entered into a Consent Decree which requires the implementation of the following pollution control projects for SO_2 and NO_X at SRP's CGS facility.

- Addition of LNB to Units 1 and 2 to reduce NO_X emissions. Coupled with the burner additions will be modifications to the furnace combustion air system on each Unit (ACC).
- Addition of a Selective Catalytic Reduction (SCR) to Unit 2. The SCR will further reduce NO_X emissions from Unit 2.
- Replacement of the existing Pullman Kellog wet limestone Flue Gas Desulfurization systems on Unit 1 and Unit 2 with new wet limestone FGD (WFGD) systems to further reduce SO_2 emissions.

The implementation schedule as laid out in the Consent Decree is as follows:.

Table 14.1 – Implementation Summary of Pollution Control Projects

Unit	Projected Operational Date	Expected Emission Rates
1 or 2	ACC – June 1, 2009	NO_X - 0.320 lb / MMBtu
2 or 1	ACC – June 1, 2011	NO_X - 0.320 lb / MMBtu
2	SCR – June 1, 2014	NO_X - 0.080 lb / MMBtu
2	FGD – January 1, 2012	SO_2 – 95% control or 0.080 lb / MMBtu
1	FGD – January 1, 2013	SO_2 – 95% control or 0.080 lb / MMBtu

C. Description of Emissions Units Subject to Best Available Retrofit Technology (BART)

The BART– affected emission units at the CGS are Units 1 and 2. These units are BART- eligible since they meet the following requirements:

1. They were "in existence" between 1962 and 1977. Units 1 and 2 were in the construction phase in this period.
2. The emissions from the combined BART-eligible units are greater than 250 tons/year. Emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and particulate matter below 10 micron size (PM_{10}) are 29,384, 20,361, and 1,008 tons per year respectively.

3. These units belong to one of the 26 categories of sources identified in the Regional Haze Rule.

Further in order to confirm that the CGS has visibility impacts on the Class I areas, CALPUFF modeling was conducted by SRP to assess impacts at 17 Class I areas. Modeling was conducted with three years of CALMET meteorological data (2001-2003). The results of the baseline CALPUFF modeling are listed in Table 2. This table provides the 8^{th} highest delta-deciview and the total 8^{th} highest deciview (Source contribution plus the natural background).

As demonstrated in Table 2, the impact of CGS on the visibility in Class I areas is more than 0.5 dv threshold that is used as a trigger for BART applicability. Therefore, Units 1 and 2 at CGS are presumed to cause or contribute to visibility impairment and are, therefore, subject-to-BART for SO_2, NO_X, and PM_{10}.

Table 14.2 – Regional Haze Impacts Due to Baseline Emissions

Class I Area	Ave. Annual Natural Background	Met Year 2001		Met Year 2002		Met Year 2003		Average Highest Total Δdv
		8th Highest Δdv	8th Highest Total Δdv	8th Highest Δdv	8th Highest Total Δdv	8th Highest Δdv	8th Highest Total Δdv	
Bandalier, NM	4.46	1.0	5.4	1.1	5.5	1.0	5.5	5.46
Bosque del Apache	4.41	1.5	5.9	1.7	6.1	1.5	5.9	5.96
Chiricahua, NM	4.36	0.8	5.2	0.6	5.0	1.1	5.5	5.23
Chiricahua, W	4.35	0.7	5.1	0.6	5.0	1.2	5.6	5.23
Galiuro W	4.32	1.0	5.3	0.8	5.1	0.9	5.2	5.2
Gila W	4.39	2.0	6.4	2.0	6.4	2.3	6.7	6.5
Grand Canyon NP	4.39	1.1	5.5	0.8	5.2	0.5	4.9	5.2
Mazatzal W	4.35	0.9	5.2	1.0	5.4	1.4	5.8	5.45
Mesa Verde NP	4.53	1.1	5.6	1.1	5.6	1.2	5.7	5.63
Mount Baldy W	4.39	1.6	6.0	1.4	5.8	2.0	6.4	6.1
Petrified Forest NP	4.41	2.5	6.9	2.8	7.2	2.7	7.1	7.1
San Pedro Parks W	4.47	0.9	5.4	1.3	5.8	1.3	5.7	5.6
Sierra Ancha W	4.36	1.0	5.3	1.3	5.6	1.7	6.0	5.6
Superstition W	4.32	1.1	5.4	1.0	5.3	1.4	5.7	5.5
Pine Mountain W	4.36	0.5	4.8	0.7	5.1	1.0	5.3	5.1
Saguaro W & NP	4.28	0.8	5.1	0.6	4.9	0.7	4.9	5.0
Sycamore Canyon W	4.40	0.8	5.2	0.7	5.1	0.8	5.2	5.2

Notes:
W: Wilderness Area; NP: National Park; NM: National Monument

D. BART for NO_X

Step 1: Identify the Existing Control Technologies in Use at the Source

NO_X emissions from both Units 1 and 2 are currently controlled by good combustion practices and overfire air. The resulting emission rate ranges from 0.45 to 0.50 lbs/MMBtu.

Step 2: Identify All Available Retrofit Control Options

The alternative NO_X control technologies for limiting NO_X emissions from Unit 1 and Unit 2 are listed as follows:

- Advanced Combustion Control-Low NO_X burners (LNB) and over fire air (OFA)
- Selective non-catalytic reduction (SNCR)
- Selective catalytic reduction (SCR)

The brief evaluation of the above control technologies is provided below:

Advanced Combustion Control (ACC). ACC, including LNB and OFA, on a dry-turbo-fired boilers are designed to control fuel and air mixing to reduce peak flame temperatures resulting in less NO_X formation. Combustion reduction and burnout are achieved in three stages within a conventional low NO_X burner. In the initial stage, combustion occurs in a fuel rich, oxygen deficient zone where the NO_X is formed. In the second stage, the exhaust gases from Stage 1 are exposed to a reducing atmosphere where hydrocarbons that react with the already formed NO_X are formed. In the third stage, internal air staging completes the combustion, but may result in additional NO_X formation. This, however, can be minimized by completing the combustion in an air lean environment. Combustion air is separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of nitrogen, rather than NO_X. Primary air (70-90%) is mixed with the fuel producing a relatively low temperature, oxygen deficient, fuel-rich zone thereby reducing the formation of fuel-bound NO_X. Secondary air representing 10-30% of the combustion air is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles mounted above the burners. Combustion is completed at this increased flame volume. This process limits the production of thermal NO_X.

Selective Non-Catalytic Reduction (SNCR). SNCR is based on a gas-phase homogeneous reaction that involves the injection of an-amine based compound into the fuel at an appropriate temperature range for reduction of NO_X. An amine-based compound such as ammonia (NH_3) or urea ($(NH_2)_2$ CO) is used as the NO_X reducing agent. When ammonia or urea is injected into the flue gas stream, it selectively reduces the NO_X into molecular nitrogen and water. At stoichiometric conditions, when the adequate residence time is reached, the overall reactions that occur may be characterized by:

Ammonia

$$4\ NO + 4\ NH_3 \rightarrow 4\ N_2 + 6\ H_2O$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Urea

$$2\ (NH_2)_2\ CO + 4\ NO + O_2 \rightarrow 4\ N_2 + 2\ CO_2 + 4\ H_2O$$

In an SNCR system, NO_X reduction does not take place in the presence of a catalyst, but rather is driven by the thermal decomposition of ammonia and urea and the subsequent reduction of NO_X. Consequently, the SNCR process operates at higher temperatures than the SCR process. The temperature of the flue gas is critical to the successful reduction of NO_X with SNCR at the point where the reagent is injected. For the ammonia injection process, the necessary temperature range is 1700 to 1900°F. The other factors affecting the performance of SNCR performance are gas mixing, residence time at operating temperatures, and ammonia slip. Since ammonia is present in the flue gas, a portion of the ammonia may oxidize at temperatures greater than 2000°F. Above 2000°F, the reaction of ammonia oxidation becomes predominant. Nitrogen monoxide is formed as a product of the reaction. Thus, when the flue gas temperature at reagent injection locations is higher than the appropriate temperature window, the SNCR process results in increased NO_X formation rather than NO_X reduction. At temperatures lower than the required temperature window, the NO_X reduction rates becomes lower, and unreacted ammonia may slip through and be emitted to the atmosphere.

Selective Catalytic Reduction (SCR). SCR is a process that involves post-combustion removal of NO_X from the flue gas utilizing a catalytic reactor. In the SCR process, ammonia injected into the flue gas reacts with the NO_X and oxygen to form Nitrogen and water by the following general reactions:

$$4\ NO + 4\ NH_3 \rightarrow 4\ N_2 + 6\ H_2O$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

These reactions take place on the surface of the catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_X decomposition reaction to about 375 to 750°F, depending on the specific catalyst and other contaminants in the flue gas. The factors affecting SCR performance are catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst deactivation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system.

The SCR system is comprised of a number of subsystems, including the SCR reactor, ammonia injection system, and ammonia storage and delivery system. The SCR reactor would be located downstream of the economizer and ESP, and upstream of the air pre-heater. From the ESP outlet, the flue gas would first pass through a low-pressure ammonia/air injection grid designed to provide optimal mixing of ammonia with flue gas. The ammonia treated flue gas would then flow through the catalyst bed and exit to the air pre-heater. The SCR system for a pulverized coal boiler typically uses a fixed bed catalyst in a vertical down-flow, multi-stage reactor.

Reduction catalysts are divided into two groups: base metal, primary vanadium, platinum, or titanium (lower temperature) and zeolite (higher temperature). Both groups exhibit advantages and disadvantages in terms of operating temperature, ammonia- NO_X ratio, and optimum oxygen concentration. The optimum operating temperature for a vanadium-titanium catalyst system is in the range of 550° to 800°F, which is significantly higher than the optimum operating temperature for the platinum catalyst systems. The vanadium-titanium catalyst begins to break down, however, when continuously operating at temperatures above this range. Operation above the maximum temperature results in oxidation of ammonia to either ammonium sulfate or NO_X, thereby actually increasing the NO_X emissions.

To achieve high NO_X control efficiencies, the SCR vendor suggests a higher ammonia injection rate than is stoichiometrically required to react all of NO_X in the combustion gases. This results in emissions of un-reacted ammonia or "ammonia slip". The various SCR vendors typically guarantee ammonia slip of about 2 ppm for systems designed for very high NO_X performance levels. This excess ammonia may react with SO_3 and water to form ammonium bisulfate $(NH_4)\ HSO_4$ and ammonium sulfate, $(NH_4)_2\ SO_4$. Higher levels of ammonia and SO_2 results in formation of higher levels of these salts. These ammonium salts may condense as the flue gases cool and can lead to increased emissions of both PM_{10} and $PM_{2.5}$. Furthermore the catalyst promotes the partial oxidation of SO_2 to SO_3, which in turn combines with water thereby increasing the formation of these ammonia salts and potential emissions of PM_{10} and $PM_{2.5}$.

Some SCR installations have experienced significant air pre-heater plugging and corrosion resulting from the deposition of ammonium bisulfate. The plugging and corrosion can cause reduced boiler efficiency, higher flue gas pressure drop, more frequent air pre-heater cleaning and washing, increased boiler downtime, and increased maintenance cost. The primary factors for controlling the formation and deposition of ammonium bisulfate are the levels of ammonia, the level of SO_3, the air pre-heater surface temperature profile, the air pre-heater surface material, and the air pre heater physical configuration. The temperature window for ammonium bisulfate formation is as wide as 300^o to 425^{o}F.

The SCR system is subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation usually results from either prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or air contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and thus a permanent condition. Catalyst suppliers typically guarantee a limited lifetime for high performance catalyst systems. Fly ash plugging generally results from excessive carryover to the catalyst or poor catalyst gas flow design.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the above control technologies are feasible options for BART at CGS.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

The alternative NO_X control technologies, ACC, SNCR, and SCR, have been successfully applied to new utility coal fired boilers, as well as retrofitted to existing coal fired boilers. The effectiveness of these technologies in reducing NO_X emissions is dependent primarily on the inlet NO_X concentrations, residence time, and operating temperatures. ACC has been demonstrated to achieve 25% to 35% reduction in uncontrolled NO_X emissions. SNCR has been demonstrated to achieve NO_X control efficiencies ranging from 30% to 50% with inlet NO_X concentration of 300 to 400 ppmvd. If staged combustion is used to reduce inlet NO_X concentrations to less than 250 ppmvd, SNCR is capable of achieving NO_X control efficiencies of only 20% to 40%. Likewise, SCR can achieve NO_X control efficiencies as high as 90% with inlet concentrations in the range of 300 to 400 ppmvd. If inlet NO_X concentrations are less than 250 ppmvd, SCR can achieve NO_X control efficiencies ranging from 70% to 80%.

In its BART analysis, CGS considered the above technologies for control of NO_X in the following sequence: ACC in both Unit 1 and Unit 2, ACC with SNCR in both Unit 1 and Unit 2, ACC in both Unit 1 and Unit 2 with SCR in Unit 2, and ACC and SCR in both Unit 1 and Unit 2. Based on the information provided by the equipment vendors, the controls listed above were estimated to reduce NO_X emissions as demonstrated in Table 14.3.

Table 14.3 – NO_X Emission Factors resulting from NO_X Controls			
Control Option	Control Technology	Unit 1	Unit 2
		Pounds/MMBtu	
	Baseline	0.433	0.466
3	ACC- Both Units	0.32	0.32
4a	ACC and SNCR- Both Units	0.224	0.224
4 b	ACC (Both Units) and SCR on Unit 2	0.32	0.08
5	ACC and SCR on both Units	0.08	0.08

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Costs of Compliance

Based on the vendor data on the capital cost and operation & maintenance cost for different control options, Table 14.4 provides the information on the annual costs associated with each of the control options.

Table 14.4 – Total Capital and Annual Costs associated with NO_X Controls					
Control Option	Control Technology	Total Capital (Million $)	Fixed Capital (Million $)	Annual O&M (Million $)	Total Annual Cost (Million $)
3	ACC- Both Units	$13.00	$1.227	0	$1.227
4a	ACC and SNCR- Both Units	$26.00	$2.454	$2.200	$4.654
4 b	ACC (Both Units) and SCR on Unit 2	$79.00	$7.4570	$1.100	$8.557
5	ACC and SCR on both Units	$145.0	$13.69	$3.400	$17.09

* Fixed capital cost calculation is based on a CRF of 0.09439, assuming an interest rate of 7%, and amortization period of 20 years.

Table 14.5 provides annual estimated emission numbers for NO_X and cost figures relating to the implementation of various control options for NO_X.

Table 14.5: Total Annual Emissions of NO_X with different options of NO_X Controls					
Factor	Baseline	Option 3	Option 4a	Option 4b	Option 5
Unit 1	10,332 tpy	7,636 tpy	5,345 tpy	7,636 tpy	1,909 tpy
Unit 2	10,029 tpy	6,887 tpy	4,821 tpy	1,722 tpy	1,722 tpy
Total (Both Units)	20,361 tpy	14,523 tpy	10,166 tpy	9,358 tpy	3,631 tpy
Reduction from Baseline	-	5,838 tpy	10,195 tpy	11,003 tpy	16,730 tpy
Incremental Reduction from earlier option	-	5,838 tpy	4,357 tpy	808 tpy	5,727 tpy

Table 14.5: Total Annual Emissions of NO_X with different options of NO_X Controls					
Factor	**Baseline**	**Option 3**	**Option 4a**	**Option 4b**	**Option 5**
Annualized Cost (Million $)	-	$1.227	$4.654	$8.556	$17.09
Cost of reduction (Dollar per ton)	-	$210	$457	$778	$1,021
Incremental cost of reduction (Dollar per ton)	-	$210	$787	$4,830	$1,489

Energy Impacts

SCR will consume significantly more energy as compared to the energy consumption in SNCR. This is due to the power required for the increased fan static pressure required to overcome the pressure drop across the catalyst bed, as well as for pumps and evaporator blower. Assuming a pressure drop of 14 inches of water across the catalyst bed, SCR applied to both units will consume 7,300 kWh more electrical power per year than SNCR (approaching 1% of the total power generation of the CGS).

Non-Air Quality Environmental Impacts

One of the most significant impacts of retrofitting SCR and SNCR is the addition of ammonia and urea storage and handling systems. Anhydrous ammonia and aqueous ammonia above 20% are considered dangerous to human health. An accidental release of anhydrous ammonia or 20% or greater aqueous ammonia is reportable to local, state, and federal agencies. In anticipation of such an incident, the site will need to develop, implement, and maintain a Risk Management Plan (RMP) and Process Safety Measures (PSM) Program.

Ammonia associated with fly ash has the potential to present several problems with the disposal and/or the use of fly ash. Once the fly ash is exposed to the SNCR process, there will be a significant quantity of soluble salts associated with fly ash. These salts are expected to be $(NH_4)HSO_4$ and $(NH_4)_2SO_4$.

Dry disposal of ash can cause the leachate and/or runoff water to contain increased concentrations of ammonia. If and when these salts are contacted with water, they will most likely be dissolved and the resulting aqueous concentration of nitrogen-containing compounds can increase in the waters associated with the ash. Table 10 below summarizes the non-air quality environmental impacts associated with the proposed BART control options.

Table 14.6 – Summary of Non-Air Quality Environmental Impacts	
Control Option	**Summary of Non-Air Quality Environmental Impacts**
ACC	- Potential to increase in loss of ignition (LOI) of flyash, which could reduce recycling sales. - Slight increase in CO_2 emissions/kWH associated with reduced boiler efficiency. - Potential for incomplete combustion (lost energy). - Potential for increased corrosion and more frequent replacement of furnace water tubes.

Table 14.6 – Summary of Non-Air Quality Environmental Impacts	
Control Option	**Summary of Non-Air Quality Environmental Impacts**
SNCR	- Addition of ammonia or urea storage and handling systems. - Anhydrous ammonia and aqueous ammonia above 20% are considered dangerous to human health and accidental releases are reportable to local, state, and federal agencies. - The facility must develop, implement, and maintain a Risk Management Plan (RMP) and Process Safety Measures Program (PSM). - Sulfuric acid in the flue gas can cause various power plant operation and maintenance problems. Condensation of sulfuric acid has a significant detrimental effect on downstream equipment, including fouling and corrosion of heat transfer surfaces in the air pre heater. - Ammonia associated with flyash has the potential to present several problems with the disposal and/or use of flyash. - Dry disposal of flyash can cause leachate and/or runoff water to contain increased concentrations of ammonia and/or nitrogen-containing compounds.
SCR	- Addition of Ammonia handling system. - Anhydrous ammonia and aqueous ammonia above 20% are considered dangerous to human health and accidental releases are reportable to local, state, and federal agencies. - The facility must develop, implement, and maintain a Risk Management Plan (RMP) and Process Safely Measures Program (PSM). - Disposal of spent catalyst containing heavy metals such as vanadium, tungsten, or molybdenum. - Increase in CO_2 emissions from power required for the increased fan static pressure required to overcome the pressure drop across the catalyst bed, as well as for pumps and evaporator blower.

Step 6: Evaluate Visibility Impacts

Four different scenarios for control of NO_x emissions were modeled for each meteorological year (2001-2003) and for all 17 Class I areas within 300 km. Brief details of the modeling results are as under:

Option 3: WFGD with ACC. The modeling result indicates that this control option provides an improvement in visibility index by approximately 0.11dv.

Option 4a: WFGD with ACC and SNCR on both units. The modeling result indicates that this control option provides an improvement in visibility index by approximately 0.19 dv.

Option 4b: WFGD with ACC on both units and SCR on Unit 2. The modeling result indicates that this control option provides an improvement in visibility index by approximately 0.22 dv.

Option 5: WFGD with ACC and SCR on both units. The modeling result indicates that this control option provides an improvement in visibility index by approximately 0.34 dv.

Table 12.7 below provides information on the cost in dollars per deciview improvement in visibility achieved by implementing the respective control options. The table also presents details on the incremental cost in dollars per deciview improvement over different control options.

Table 12.7 – Summary for NO_X BART					
Factor	**Option 2 Baseline, WFGD**	**Option 3 ACC**	**Option 4a ACC w/ SNCR**	**Option 4b ACC w/ SCR for Unit 2**	**Option 5 ACC w/ SCR**
Reduction in Emission (tpy)	-	5,838	10,195	11,003	16,730
Annualized Cost (Million $)	-	$1.227	$4.654	$8.557	$17.09
Visibility Index Improvement Over Baseline (Δ dv)	-	0.11	0.19	0.22	0.34
Incremental Cost Effectiveness (Million $/dv)	-	$11.15	$24.50	$38.89	$50.25

Step 7: Select BART

After reviewing the BART analysis provided by the company, and based upon the information above, ADEQ has determined that BART control at CGS for NO_x is ACC (Low NO_x burners with OFA) with an associated NO_x emission rate of 0.32 lbs/MMBtu on 30-day rolling average basis.

E. PM_{10} BART

Step 1: Identify the Existing Control Technologies in Use at the Source

PM_{10} emissions from the facility are currently controlled through the use of a hot-side ESP.

Steps 2-6: Streamlined Review

SRP's BART analysis for PM_{10} was limited to a statement that the current emission levels associated with the existing controls at the Coronado Generating Station range from 0.01 to 0.03 lb/MMBtu. As noted in Section X, PM_{10} BART for similar emissions units with similar emissions controls was determined to be 0.03 lb/MMBtu. Since SRP's CGS is already meeting or exceeding the stringency of the emissions limitation, further analysis was determined to be unnecessary.

Step 7: Select BART

After reviewing the analysis provided by SRP, and the information presented above, ADEQ has determined that BART for PM_{10} from Units 1 and 2 is no further control, and an emissions limitation of 0.03 lb/MMBtu. The PM_{10} emissions will be measured by conducting EPA Method 201/202 tests.

F. SO_2 BART

Step 1: Identify the Existing Control Technologies in Use at the Source

SO_2 emissions are currently controlled with the use of low-sulfur coal and partial wet flue gas desulfurization. The resulting emission rate ranges from 0.6 to 0.7 lbs/MMBtu.

Step 2: Identify All Available Retrofit Control Options

Following control options are available for control of SO_2.

- Wet Flue Gas Desulfurization
- Spray Dryer Absorber
- Dry Sorbent Injection

A brief evaluation of the above control technologies is provided below:

Wet Flue Gas Desulfurization (WFGD). This control option uses limestone or lime to react with SO_2 in the flue gas. The temperature of the flue gas is reduced to its adiabatic saturation temperature and the SO_2 is removed from the flue gas by reaction with the alkaline medium. SO_2 and other acid gases are absorbed into the scrubbing slurry, which falls into the lower section of the reaction tank. Finely ground limestone and make-up water are added to the reaction tank to neutralize and regenerate the scrubbing slurry.

Limestone scrubbing introduces limestone slurry into the scrubber. The SO_2 is absorbed, neutralized, and partly oxidized to calcium sulfite and calcium sulfate in line with the following reaction:

$$CaCO_3 + SO_2 + \frac{1}{2} H_2O \rightarrow CaSO_3 \bullet H_2O + CO_2$$

$$CaSO_3 \cdot H_2O + 1\frac{1}{2} H_2O + \frac{1}{2} O_2 \rightarrow CaSO_4 \bullet 2H_2O$$

Lime scrubbing is similar to limestone scrubbing in equipment and process flow, except that lime is a more reactive reagent than limestone. The reactions for lime scrubbing are as follows:

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \bullet \frac{1}{2}H_2O + \frac{1}{2}H_2O$$

$$Ca(OH)_2 + SO_2 + \frac{1}{2}O_2 + H_2O \rightarrow CaSO_4 \bullet 2H_2O$$

If lime or limestone is used as the reagent for SO_2 removal, additional equipment is needed to prepare the lime/limestone slurry and collecting and dewatering the resultant sludge. Calcium sulfite sludge is difficult to mechanically dewater and is typically stabilized with fly ash for landfilling. Calcium sulfate is stable and is easily dewatered through mechanical processes. To produce calcium sulfate, an air injection blower is needed to supply oxygen for the second reaction to occur (forced oxidation).

Dry Sorbent Injection (DSI). In DSI systems, a dry powdered alkaline material is injected into the hot gas stream to neutralize the acidic species like SO_2, and the resulting solid salts and remaining excess alkaline material is collected by a downstream particulate capture device. Various alkaline materials, both chemically processed and naturally occurring, have seen application in dry scrubbing. Dry hydrated lime, a calcium based alkaline sorbent, is in wide use in dry scrubbing.

Spray Dryer Absorber (SDA). The process consists of the SDA module, a down-stream fabric filter, a reagent preparation system and a product handling system. Hot, untreated flue gas is introduced into a spray dryer absorption chamber contacts a fine spray of reagent slurry. A significant part of the SO_2 in the flue gas is rapidly absorbed into the alkaline droplets. The control of gas distribution, slurry flow rate, and droplet size ensure that the droplets are dried to a fine powder before they touch the chamber walls of the spray dryer absorber.

A portion of the dry product, consisting of fly ash and reaction product, drops to the bottom of the absorption chamber and is discharged. The treated flue gas flows to a particle separator, where the remaining suspended solids are removed. Outlet gasses from the particulate separator pass on to the stack by means of an induced draft fan.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the referenced control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

SRP and EPA's consent decree stipulates the installation of WFGDs for both the units. WFGD is the most effective control technology available for controlling SO_2 emissions. Since SRP is committing to the WFGD technology, other control technologies are not evaluated from this point forward in the BART analysis.

Table 12.8 – Annual SO_2 Emissions resulting from SO_2 Controls

Control Option	Control Technology	Unit 1	Unit 2
		Pounds/MMBtu	
1	Baseline-Partial FGD	0.610	0.689
2	Wet FGD	0.08	0.08

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Costs of Compliance

Based on the vendor data on the capital cost and operation & maintenance cost for different control options, Table 9 provides the information on the annual costs associated with each of the control options.

Table 12.9 – Total Capital and Annual Costs associated with SO_2 Controls

Control Option	Control Technology	Total Capital Cost	Fixed Capital Cost	Annual O&M	Total Annualized Cost
1	Baseline- Partial FGD	--	--	--	--
2	WFGD	$347,000,000	$32,753,330	$11,600,000	$44,353,330

* Fixed capital cost calculation is based on a Capital Recovery Factor (CRF) of 0.09439, assuming an interest rate of 7%, and amortization period of 20 years.

Table 12.10 provides annual estimated emission numbers for SO_2 and cost figures relating to the implementation of WFGDs.

Table 12.10 – Total Annual Emissions of SO_2 and cost of reduction with WFGD		
	Baseline, Option 1	**Option 2, WFGD**
Unit 1	14,556 tpy	1,909 tpy
Unit 2	14,828 tpy	1,722 tpy
Total (Both Units)	29,384 tpy	3,631 tpy
Reduction from Baseline	-	25,753 tpy
Annualized Cost	-	$ 44,353,330
Cost of reduction ($ per ton)	-	$1,722

Step 6: Evaluate Visibility Impacts

The new WFGD control scenario was modeled for each meteorological year (2001-2003) and for all 17 Class I areas within 300 km. The modeling result indicates that the installation of a WFGD will provide for significant visibility benefit. The highest visibility improvement will occur at the Petrified National Forest where an improvement of 1.38 Δdv is expected.

Table 12.11 provides information on annualized cost and the cost in dollars per deciview average improvement in visibility achieved by implementing the control option.

Table 12.11 – Summary for SO_2 BART		
	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

Step 7: Select BART

Based on its review of the company's analysis and the information above, the Department accepts SRP's recommended BART control of WFGDs for both units with an associated SO_2 emission rate of 0.08 lbs/MMBtu on 30-day rolling average basis.

Exhibit F

EPA Air Pollution Control Cost Manual, 6th Ed., Jan. 2002.

EPA/452/B-02-001

EPA AIR POLLUTION CONTROL COST MANUAL

Sixth Edition

EPA/452/B-02-001

January 2002

United States Environmental Protection Agency
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

1.1 Role of Cost in Setting of Regulations

Cost has an important role in setting many state and federal air pollution control regulations. The extent of this role varies with the type of regulation. Some types of regulations, such as Maximum Achievable Control Technology (MACT) standards, explicitly use costs in determining their stringency. This use may involve a balancing of costs and environmental impacts, costs and dollar valuation of benefits, or environmental impacts and economic consequences of control costs. Other types of regulations *(*e.g., National Ambient Air Quality Standards), use cost analysis to choose among alternative regulations with the same level of stringency. For these regulations, the environmental goal is determined by some set of criteria which do not include costs. However, regulators use cost-effectiveness analysis to determine the minimum cost way of achieving the goal.

For some regulations, cost influences enforcement procedures or requirements for demonstration of progress towards compliance with an air quality standard. For example, the size of any monetary penalty assessed for noncompliance as part of an enforcement action must include the cost of the controls that were not installed by the noncompliant facility. For regulations without a fixed compliance schedule, demonstration of reasonable progress towards the goal is sometimes tied to the cost of attaining the goal on different schedules.

Cost is also a vital input to the EPA's standard setting and regulatory processes. Through various Executive Orders and acts, EPA has been charged with performing a number of detailed economic and benefit-cost analyses on each proposed rulemaking to assess their economic efficiency and assure the public the best possible regulation has been chosen from among alternative regulations. Cost also plays an input role in determining the economic impact of each regulatory alternative on sensitive populations, small businesses, employment, prices, and market and industry structure.

This Manual provides up-to-date information on point source and stationary area source air pollution controls for volatile organic compounds (VOCs), particulate matter (PM), oxides of nitrogen (NO_X), and some acid gasses (primarily SO_2 and HCl). It is not a source of information for non-stationary area (e.g. emissions from fugitive dust sources, agricultural sources) and mobile sources. Furthermore, this Manual does not directly address the controls needed to control air pollution at electrical generating units (EGUs) because of the differences in accounting for utility sources. Electrical utilities generally employ the EPRI Technical Assistance Guidance (TAG) as the basis for their cost estimation processes.[1] Finally, new and emerging technologies are not generally within the scope of this Manual. The control devices included in this Manual are generally well established devices with a long track record of performance.

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[1] This does not mean that this Manual is an inappropriate resource for utilities. In fact, many power plant permit applications use the Manual to develop their costs. However, comparisons between utilities and across the industry generally employ a process called "levelized costing" that is different from the methodology used here.

1.2 Purpose of the Manual

The objectives of this Manual are two-fold: (1) to provide guidance to industry and regulatory authorities for the development of accurate and consistent costs (capital costs, operating and maintenance expenses, and other costs) for air pollution control devices, and (2) to establish a standardized and peer reviewed costing methodology by which all air pollution control costing analyses can be performed. To perform these objectives, this Manual, for the last twenty-five years, has compiled up-to-date information for "add-on" (downstream of an air pollution source) air pollution control systems and provided a comprehensive, concise, consistent, and easy-to-use procedure for estimating and (where appropriate) escalating these costs. Over time, the accessability of this Manual and its ease of use has significantly increased. Its early editions were only available in hard copy by request, mailed from the EPA's Office of Air Quality Planning and Standards in Research Triangle Park, North Carolina. Later editions became available electronically; first through the EPA's Technology Transfer network (TTN) bulletin board in the early nineties, later as a fully accessible series of documents on the Internet through the Agency's Clean Air Technology Center. The Manual is a living document, evolving continuously to meet the changing needs of its customers, and now, with supporting programs for the personal computer such as the CO$T-AIR spreadsheets and the Air Compliance Advisor that streamline and simplify the input of site-specific information, the Manual is even more accessible and important.

As always, to achieve its objectives, the Manual provides detailed engineering information that reflects the latest innovations in the industry and costing information that is up-to-date and relevant. The accuracy of the information in the Manual works at two distinct levels. From a regulatory standpoint, the Manual estimating procedure rests on the notion of the "study" (or rough order of magnitude - ROM) estimate, nominally accurate to within ± 30%. This type of estimate is well suited to estimating control system costs intended for use in regulatory development because they do not require detailed site-specific information necessary for industry level analyses. While more detailed data are available to the regulator, those data are generally proprietary in nature (which limits their ability to be published), costly to gather, and too time consuming to quantify. Therefore, for regulatory analysis purposes, study estimates offer sufficient detail for an assessment while minimizing its costs. The Manual and its supporting programs are also well suited to customization by industrial sources to provide more accurate assessments of control cost sizing and cost that can be used for scoping level decision making and planning purposes. While such customized analyses are by definition of greater accuracy than the generic study level analysis of the regulator, the Agency does not make any claim for a greater accuracy than the study level's nominal ±30 percent.

The Manual offers an additional, benefit to its users. When industry uses the Manual and its support programs to determine its control costs for permitting purposes, and the regulator uses the Manual (and its support programs) to validate industry's permit, the approval process can be faster and less expensive. With a common peer reviewed costing methodology used by

Exhibit G

EPA Response Brief, *Nat'l Parks Conservation Ass'n v. EPA*,
No. 1:11-cv-1548-ABJ (brief filed Feb. 19, 2013).

ORAL ARGUMENT NOT YET SCHEDULED

No. 12-5211

IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

NATIONAL PARKS CONSERVATION ASSOCIATION, et al.,
Plaintiff-Appellees,

v.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al.,
Defendant-Appellees,

and

STATE OF ARIZONA,
Intervenor Defendant-Appellant.

On Appeal from the U.S. District Court for the District of Columbia,
No. 1:11-cv-1548-ABJ (Hon. Amy Berman Jackson)

EPA'S RESPONSE BRIEF

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IN THE UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

NATIONAL PARKS CONSERVATION ASSOCIATION, et al., *Plaintiff-Appellees,*	)	
v.	)	No. 12-5211
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, et al., *Defendant-Appellees,*	)	
STATE OF ARIZONA, *Intervenor Defendant-Appellant*	)	

EPA'S CERTIFICATE OF COUNSEL

Pursuant to Circuit Rule 28(a)(1), counsel for Appellee United States Environmental Protection Agency submits this certificate as to parties, rulings, and related cases.

A. Parties and Amici.

The following parties were Plaintiffs in the district court and are Appellees here: National Parks Conservation Association, Sierra Club, Montana Environmental Information Center, Environmental Defense Fund, Grand Canyon Trust, San Juan Citizens Alliance, Our Children's Earth Foundation, Plains Justice, and Powder River Basin Resource Council.

The following parties were Defendants in the district court and are Appellees here: United States Environmental Protection Agency ("EPA") and Lisa P. Jackson, in her official capacity as Administrator of EPA.

The following party was an Intervenor-Defendant in the district court and is Appellant here: State of Arizona.

B. Ruling Under Review.

The ruling under review is the amended Partial Consent Decree that the U.S. District Court for the District of Columbia, Judge Amy Berman Jackson, signed and entered on March 30, 2012, in No. 1:11-cv-01548-ABJ (Docket # 21).

C. Related Cases.

Undersigned counsel is not aware of any other cases in which this Court or another court is considering the Clean Air Act claims that Plaintiffs raised in the district court, or is considering the validity of the Consent Decree that the district court entered.

Arizona claims that the Consent Decree is inconsistent with the Act because it contemplates that EPA may promulgate a Federal Implementation Plan that, in Arizona's view, is inconsistent with the Clean Air Act. Arizona may raise the same or similar issues in a case currently pending before the Ninth Circuit, in which Arizona challenges a Federal Implementation Plan directly. The case is *State of Arizona v. EPA*, No. 13-70366 (9th Cir.).

Respectfully submitted,

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Dated: February 19, 2013

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TABLE OF AUTHORITIES

Authorities on which we principally rely are marked with an asterisk.

CASES

RULES AND REGULATIONS:

GLOSSARY

EPA	U.S. Environmental Protection Agency
FIP	Federal Implementation Plan
SIP	State Implementation Plan

INTRODUCTION AND STATEMENT OF THE CASE

In 1999, the U.S. Environmental Protection Agency ("EPA") promulgated a "Regional Haze Rule" to improve air quality and protect visibility in areas such as National Parks and National Monuments. The promulgation of the Regional Haze Rule, and its 2005 and 2006 revisions, triggered an obligation under the Clean Air Act for each State to demonstrate to EPA that it would implement the rule through the provisions of its "State implementation plan" ("SIP"). By 2009, however, Arizona was one of many states that had not submitted all the necessary elements to incorporate the requirements of the Regional Haze Rule into its SIP.

Arizona's failure, in turn, triggered EPA's own duties under the Act. EPA made a formal finding, the "2009 Finding," that Arizona had not met its statutory duty to submit all required elements of a SIP. At that point, EPA had a statutory duty either to approve a SIP that would effectuate the Regional Haze Rule in Arizona, or to promulgate a federal implementation plan ("FIP") instead, within two years. When EPA did not take either of those actions, Plaintiffs here sued to enforce EPA's duty. EPA settled the case, negotiating a Consent Decree with Plaintiffs under which EPA would either approve a proposed SIP for Arizona or promulgate a FIP by a specified date. The district court entered this Consent Decree. *See National Parks Conservation Ass'n v. EPA*, D.D.C. No. 1:11-cv-1548-ABJ, Docket # 21 (March 30, 2012).

Arizona now appeals the district court's entry of the Consent Decree, claiming that EPA has no authority to promulgate a FIP pursuant to the Consent Decree because the 2009 Finding was invalid. As the district court correctly found, that argument is an improper and untimely attack on the 2009 Finding itself, and cannot now be raised as an objection to the Consent Decree. Arizona does not contest the district court's jurisdictional analysis on this point, and the court's final judgment entering the consent decree must therefore be affirmed.

STATEMENT OF JURISDICTION

Under 42 U.S.C. § 7604, the district court had jurisdiction to consider Plaintiffs' claims that EPA had failed to perform a nondiscretionary duty under the Act. This court has appellate jurisdiction over the entry of the Consent Decree under 28 U.S.C. § 1292(a)(1). Arizona obtained an extension of time to file a notice of appeal pursuant to Federal Rule of Appellate Procedure 4(a)(5), and filed a timely notice of appeal.

The district court held that it was without jurisdiction to consider the validity of EPA's 2009 Finding, including Arizona's present argument that the 2009 Finding was not a valid basis for EPA to undertake the obligations described in the Consent Decree. The Clean Air Act, 42 U.S.C. § 7607(b)(1), required any such argument to be presented to a Court of Appeals within 60 days of that Finding's publication in the Federal Register on January 15, 2009. This holding was correct and should be affirmed. *See infra* pp. 16-18.

STATEMENT OF THE ISSUES

1. The district court held that Arizona's argument opposing the Consent Decree constituted an untimely attack on EPA's 2009 Finding, and that the district court therefore lacked jurisdiction to consider it. Did this holding constitute an error of law?
2. Did the district court, and does this Court, lack jurisdiction over Arizona's arguments based on the interrelated doctrines of ripeness and standing?
3. Is the Consent Decree, which recognizes the 2009 Finding as a sufficient basis to trigger EPA's obligations under Section 110(c) of the Clean Air Act, 42 U.S.C. § 7410(c), consistent with the provisions of the Act?

LEGAL BACKGROUND AND STATEMENT OF FACTS

I. THE CLEAN AIR ACT'S SYSTEM OF COOPERATIVE FEDERALISM

The Clean Air Act protects the nation's air quality through a system of cooperative federalism. The Act contemplates that the federal government (through EPA) will establish standards that protect air quality, and that each State will implement those standards through State Implementation Plans ("SIPs"), conforming to the minimum requirements of the Act, that control sources of air pollution within the State. By this process, the Act makes "the States and the Federal Government partners in the struggle against air pollution." *General Motors Corp. v. United States*, 496 U.S. 530, 532 (1990).

This system is evident in the underlying provisions of the Act that were at issue in the district court case here. Section 169A of the Act 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" that may be caused by man-made air pollution. 42 U.S.C. § 7491(a)(1).[1] The Act directs EPA to promulgate regulations that will assure "reasonable progress toward meeting th[is] national goal." *Id.* § 7491(a)(4). EPA must require each State's SIP to "contain such emission limits, schedules of compliance and other measures as may be necessary to make reasonable progress" toward protecting visibility in Class I areas. *Id.* § 7491(b)(2).

After EPA promulgates the necessary regulations, the States' role in protecting visibility is established in Section 110 of the Act, 42 U.S.C. § 7410. Each State must submit an implementation plan to EPA that includes "emission limitations and other control measures" that will meet the applicable requirements of the entire Act, including the requirements for visibility protection set forth in Section 169A. *Id.* §§ 7410(a)(1), 7410(a)(2)(A), 7410(a)(2)(J). Revisions to an existing SIP are treated similarly. *See* 42 U.S.C. § 7410(k), (*l*). EPA must determine within 60 days whether

[1] "Class I Federal areas" in which "visibility is an important value" are designated by the Secretary of the Interior in consultation with Federal land managers. *See* 42 U.S.C. § 7491(a)(2); *see also id.* § 7472(a) (defining areas designated as Class I areas). Arizona currently contains twelve such areas, including Grand Canyon National Park and Petrified Forest National Park. *See* 40 C.F.R. § 81.403.

any SIP submission constitutes a complete submission that requires action by the Administrator – or, if EPA does not make such a "completeness finding" within six months, the submission is deemed complete. *Id.* § 7410(k)(1)(B). Then, within twelve months after the submission is found or deemed to be complete, EPA must approve or disapprove the SIP. *Id.* § 7410(k)(3). EPA may not approve a SIP revision that would interfere with any applicable requirement of the Act. *Id.* § 7410(*l*).

Within this system, each State has substantial discretion in how it implements the Act's air quality objectives. But where a State fails to fulfill its obligation to submit a timely plan that meet the Act's requirements, the Act provides a backstop of federal controls. Section 110 of the Act allows the Administrator of EPA to make a finding "that a State has failed to make a required submission" or that a "plan revision submitted by the State does not satisfy the minimum criteria" for a complete submission. 42 U.S.C. § 7410(c)(1). Once the Administrator makes such a finding, the Act imposes upon EPA a nondiscretionary duty to "promulgate a Federal implementation plan [FIP]. . . within 2 years." *Id.* The Administrator is relieved of that duty only if "the State corrects the deficiency" and the Administrator approves the SIP revision prior to promulgating a FIP. *Id.*

II. EPA's Regional Haze Rule and Completeness Findings

EPA promulgated a Regional Haze Rule in 1999 to effectuate the visibility protection provisions of the Act. *See* "Regional Haze Regulations," 64 Fed. Reg.

35,714 (July 1, 1999); *see also American Corn Growers Ass'n v. EPA*, 291 F.3d 1, 4-5 (D.C. Cir. 2002) (describing the Regional Haze Rule).[2] As this Court described the Regional Haze Rule, it established benchmarks for progress toward the national goal of visibility protection, including the improvement of visibility on the worst days with no degradation on the best days. *American Corn Growers*, 291 F.3d at 4. EPA generally did "not specify what control measures a state must implement" in order to achieve these goals. *Id.* The Regional Haze Rule also gave States up to 60 years to achieve natural visibility conditions, or more time if a State could demonstrate that the 60-year goal was unreasonable. *Id.*

Although the proposed rule had given states only twelve months to submit the elements of a SIP addressing regional haze, the final Regional Haze Rule contained extended and variable deadlines for the submission of SIP revisions. *See* 64 Fed. Reg. at 35,723. EPA expected that many SIP revisions would be due as soon as July 2005, but that almost all would be due by July 2008. *Id.* Congress later established a deadline of December 17, 2007 for the submission of regional haze SIPs. *See* 42 U.S.C. § 7407(d)(6), (7).

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[2] EPA made amendments to the Regional Haze Rule in 2005 and 2006 in response to this Court's decisions in *American Corn Growers* and in *Center for Energy and Economic Development v. EPA*, 398 F.3d 653 (D.C. Cir. 2005). *See* "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations," 70 Fed. Reg. 39,104 (July 6, 2005); "Regional Haze Regulations; Revisions," 71 Fed. Reg. 60,612 (Oct. 13, 2006).

The regulations that prescribe the content of State regional haze SIP submissions are codified in 40 C.F.R. §§ 51.308 and 51.309. Section 51.308 requires each State to submit a regional haze SIP that establishes reasonable progress goals for the State's mandatory Class I areas and long-term strategies for achieving those goals, including the implementation of control technology at certain sources. Section 51.309 varies those requirements for a handful of states, which may submit a regional haze SIP based on the recommendations of the Grand Canyon Visibility Transport Commission. *See* 40 C.F.R. § 51.309(b)(1)-(3). States that submit a SIP conforming to the Transport Commission's recommendations are deemed "to comply with the requirements for reasonable progress *with respect to the 16 Class I areas*" that the Transport Commission addressed. *Id.* § 51.309(a) (emphasis added). But for any "additional mandatory Federal Class I areas" within a State, the State must either submit a SIP conforming to Section 51.308, or it must establish "reasonable progress goals" under the similar provision of Section 51.309(g)(2).

Arizona submitted a proposed regional haze SIP in 2008 that was intended to satisfy the requirements of Section 51.309 "for Arizona's four mandatory Class I areas on the Colorado Plateau." *See* Ariz. App. 22. At that time, however, Arizona admitted that it had not included all the elements necessary for a complete submission. Specifically, Arizona informed EPA in its submission letter that its plan "does not include provisions under § 309(d)(4) or § 309(g)." *See id.*

In 2009, EPA reviewed the status of State SIP submissions under the regional haze regulations. *See* "Finding of Failure to Submit State Implementation Plans Required by the 1999 Regional Haze Rule," 74 Fed. Reg. 2392 (Jan. 15, 2009) (Ariz. App. 25) (the "2009 Finding"). EPA found that "37 states, the District of Columbia, and the U.S. Virgin Islands have failed to make all or part of the required SIP submissions to address regional haze." *Id.* at 2392 (Ariz. App. 26). Consistent with Arizona's letter, EPA acknowledged that Arizona had "opted to develop SIPs based on the recommendations of the Grand Canyon Visibility Transport Commission." *Id.* However, "for areas other than the 16 Class I areas" that the Commission addressed, EPA acknowledged that Arizona had "failed to submit the plan elements required by 40 C.F.R. § 51.309(g), the reasonable progress requirements." *Id.* Arizona had also failed to submit a program for control of sulfur dioxide from stationary sources under § 51.309(d)(4). *Id.* Citing Section 110(c) of the Act, EPA stated that "[t]his finding starts the two year clock for the promulgation by EPA of a FIP." *Id.*

III. SETTLEMENT OF PLAINTIFFS' NONDISCRETIONARY DUTY CLAIMS

On August 29, 2011, Plaintiffs filed their Complaint in this case. In relevant part, their Complaint raised causes of action under 42 U.S.C. § 7604(a)(2), the citizen suit provision of the Act, which allows a civil action "against the Administrator where there is alleged a failure of the Administrator to perform an act or duty under this chapter which is not discretionary with the Administrator." *See National Parks*

Conservation Ass'n v. EPA, D.D.C. No. 1:11-cv-1548, Docket #1. In the portion of their Complaint relevant to Arizona, Plaintiffs cited EPA's January 15, 2009 Finding that Arizona had submitted some, but not all, of the required elements of a regional haze SIP. *Id.* ¶ 40. Plaintiffs claimed Section 110(c) of the Act, 42 U.S.C. § 7410(c), therefore imposed a nondiscretionary duty upon EPA to promulgate a final regional haze FIP for Arizona, or to approve a SIP revision, by January 15, 2011. *Id.* ¶ 41. Plaintiffs alleged that EPA had not performed that duty, and sought an order compelling EPA to promulgate a FIP.

EPA did not raise any defenses to its failure to act upon the 2009 Finding, and instead negotiated a proposed Consent Decree and lodged it with the district court. *See National Parks Conservation Ass'n*, Docket #4 (Consent Decree as lodged); Docket # 21 (Consent Decree as entered by the court). The Consent Decree imposed upon EPA only those obligations that were already present in the Act, but established new deadlines for those obligations. Thus, the Consent Decree established a deadline of May 15, 2012 for EPA to sign a notice proposing action to approve or disapprove a SIP, promulgate a FIP, or a combination of those actions that would satisfy the requirements of the 1999 Regional Haze Rule with respect to Arizona. Consent Decree Table A (Ariz. App. 8-9). The Consent Decree also required EPA to take final action on that proposal by November 5, 2012. *Id.* Other than settling the matter of the Act's deadlines for nondiscretionary duties, the Consent Decree did not purport to constrain EPA's discretion to approve or disapprove any SIP submission, nor did it mandate a FIP for any State. Consent Decree ¶ 11 (Ariz. App. 11).

After EPA and the Plaintiffs lodged the Consent Decree, Arizona moved to intervene in the case. Arizona claimed that it had submitted a proposed SIP on February 28, 2011 and that EPA had not yet acted upon that submission. *National Parks Conservation Ass'n*, Docket #8, at 3-4. Arizona complained that the Consent Decree imposed obligations on EPA without regard for the process by which EPA might act on Arizona's submission. *Id.* Ultimately, the parties stipulated that Arizona could intervene for the sole purpose of making its argument that EPA was required to act on Arizona's February 2011 SIP submission before it could legally promulgate a FIP. *See National Parks Conservation Ass'n*, Docket #12 (Ariz. App. 2).

The district court entered the Consent Decree over Arizona's objections as intervenor. *See National Parks Conservation Ass'n*, Docket #35 (Memorandum and Order, May 25, 2012) (Ariz. App. 16). The court noted that Arizona had not presented arguments within the scope of its stipulated participation in the case, and had instead raised an argument that the 2009 Finding was invalid. *Id.* at 2-3 (Ariz. App. 17-18). And any challenge to the 2009 Finding was untimely under the Act, which sets a 60-day window to seek review of final agency actions. *Id.* at 3 (Ariz. App. 18) (citing 42 U.S.C. § 7607(b)). The court further held that Arizona's submission of a new regional haze SIP after the 2009 Finding did not affect the two-year period established by Section 110(c) of the Act, which is stopped only if the State corrects the deficiency *and* the Administrator approves the SIP. *Id.* at 4 (Ariz. App. 19); *see also* 42 U.S.C. § 7410(c)(1). Because that event had not occurred, Arizona's objections did not require the Court to refuse entry of the Consent Decree.

IV. EPA'S SUBSEQUENT ACTIONS RELEVANT TO ARIZONA'S PROPOSED SIP

After entry of the Consent Decree, EPA has continued to review Arizona's SIP submissions to determine the appropriate action under the Act and the Consent Decree. That process has led to several additional steps that are part of the context for this appeal.

First, EPA has partially acted upon Arizona's regional haze SIP submissions. At this time, EPA has taken final action to approve some parts of Arizona's 2011 submission, disapprove other parts of that submission and promulgate a partial FIP. *See* "Approval, Disapproval and Promulgation of Air Quality Implementation Plans; Arizona," 77 Fed. Reg. 72,512 (Dec. 5, 2012). EPA has also proposed two actions that would partially approve and partially disapprove Arizona's 2011 regional haze SIP submission and would disapprove Arizona's 2008 submission, but EPA has not yet taken final action on those proposals. *See* "Partial Approval and Disapproval of Air Quality Implementation Plans; Arizona," 77 Fed. Reg. 75,704 (Dec. 21, 2012); Partial Disapproval of State Implementation Plan; Arizona; Regional Haze Requirements," 78 Fed. Reg. 8083 (Feb. 5, 2013).

Second, several deadlines in the Consent Decree have been amended by stipulation of the parties. Those deadlines include EPA's deadlines to complete its review of the remaining portions of Arizona's SIP submittal. In each case, the modification has been in Arizona's favor, as it has given EPA more time to confer with Arizona and consider whether its submissions can be approved.

SUMMARY OF ARGUMENT

Arizona's entire opening brief is committed to the merits of its claim that the Consent Decree is inconsistent with the Act. It claims that the district court abused its discretion by entering a Consent Decree that conflicts with the Act. This argument completely fails to address the actual basis for the district court's decision. The district court rejected Arizona's argument about a potential conflict with the Act, but it did so on jurisdictional grounds. Because Arizona does not even attempt to show any error in the district court's jurisdictional analysis, its appeal must be rejected.

Even if Arizona had challenged the district court's jurisdictional decision, the court's analysis of its own jurisdiction must be affirmed because it is correct. Arizona's merits argument is based upon the premise that EPA's 2009 Finding was invalid, and that the two-year clock in Section 110(c) of the Act never began to run. The district court correctly recognized that this argument attacks the 2009 Finding itself, and the Act gives parties such as Arizona only 60 days to challenge such findings after they are published. Arizona's opening brief does nothing to dispel the district court's understanding of Arizona's claims, nor its conclusion that those claims are untimely.

Another jurisdictional basis exists on which to dismiss Arizona's appeal. Arizona alleges only that the promulgation of a FIP would be illegal, but the Consent Decree does not require promulgation of a FIP. Although it sets deadlines for EPA to act, it does not dictate that EPA's action must be a FIP, but rather preserves EPA's discretion to take appropriate action under the Act. Arizona's claims are therefore unripe until EPA acts – at which point vacating the Consent Decree can no longer provide Arizona with relief. Arizona's challenge to the Consent Decree, therefore is nonjusticiable.

If this Court should reach the merits, Arizona shows no inconsistency with the Act that could overturn EPA's voluntary settlement of Plaintiffs' colorable legal claims. The Consent Decree does not require EPA to do anything inconsistent with the Act: Just as Section 110(c) contemplates, the Consent Decree allows EPA to take a variety of actions, separately or in combination, to ensure that the requirements of the Act are met – including approving Arizona's SIP entirely or in part.

STANDARD OF REVIEW

The decision to approve a consent decree is committed to the discretion of the district court. *See, e.g.*, *Pigford v. Glickman*, 206 F.3d 1212, 1216 (D.C. Cir. 2000). The district court abuses its discretion when it makes an error of law. *See, e.g.*, *Kellmer v.*

Raines, 674 F.3d 848, 851 (D.C. Cir. 2012). In the absence of any errors of law, this Court should affirm the district court's approval of a consent decree as long as the district court has shown an appreciation of the relevant facts and reasoned analysis of those facts. *Pigford*, 206 F.3d at 1217.

The district court may not "approve a settlement agreement that violates a statute." *Southeastern Fed. Power Customers, Inc. v. Green*, 514 F.3d 1318, 1321 (D.C. Cir. 2008). However, the court also does not have to analyze whether Plaintiffs' claims are correct or whether a statutory violation has occurred. The court must only "satisfy itself of the settlement's overall fairness to beneficiaries and consistency with the public interest." *Citizens for a Better Envt. v. Gorsuch*, 718 F.2d 1117, 1126 (D.C. Cir. 1983). If a consent decree meets these criteria, the district court may approve it even if it requires more or less than the underlying statute. *United States v. Microsoft Corp.*, 147 F.3d 935, 944 (D.C. Cir. 1998).

ARGUMENT

I. THE DISTRICT COURT DID NOT HAVE JURISDICTION TO REVIEW EPA'S FINDING.

A. Arizona completely fails to address the basis for the district court's decision.

Arizona cannot show that the district court abused its discretion in entering the Consent Decree because it does not identify any error of law in the district court's decision. Arizona's argument below and in this appeal is simply stated: The Consent

Decree "allows the EPA to impose a federal implementation plan for regional haze," but any such FIP would be "illegal under the Act." Ariz. Br. at 8; *see also id.* at 3 (Issues Presented). The district court did not commit any error on this issue because it did not reach the merits. Instead, the district court held that it had no jurisdiction to consider Arizona's arguments about inconsistency between the Consent Decree and the Act because those arguments were not timely. *See* Op. at 2 (Ariz. App. 17).[3]

In its opening brief, Arizona does not acknowledge this essential point. Its Jurisdictional Statement explains why this Court has jurisdiction to review the district court's entry of a consent decree, but it does not explain why the district court had jurisdiction to consider its arguments regarding EPA's authority to take action based upon the 2009 Finding. Ariz. Br. at 1-2. Indeed, Arizona does not even mention the statutory provision, 42 U.S.C. § 7607(b)(1), that the district court cited to find that it "lacks jurisdiction to hear" Arizona's arguments. Op. at 2 (Ariz. App. 17). Arizona also does not contest the district court's understanding that, in opposing the Consent Decree, Arizona was actually attacking EPA's 2009 Finding. *See* Op. at 3 (Ariz. App. 18).

[3] The court commented in a footnote that it considered the Consent Decree to be consistent with the Act. *See* Op. at 3 n.1 (Ariz. App. 18). However, this was not the basis for the court's rejection of Arizona's argument, which clearly rested on jurisdictional grounds.

The district court's conclusion about its own jurisdiction was a sufficient basis for its decision.[4] Because Arizona does not challenge that ruling in its opening brief, it has waived its opportunity to claim abuse of discretion or any other error. *See, e.g.*, *Petit v. U.S. Dept' of Educ.*, 675 F.3d 769, 779 (D.C. Cir. 2012); *see also, e.g.*, *Lake Carriers' Ass'n v. EPA*, 652 F.3d 1, 10 n.9 (D.C. Cir. 2011) (applying the rule that arguments first raised in a reply brief are waived). This alone is enough to affirm the district court's approval of the Consent Decree.

B. The district court correctly held that it had no jurisdiction over Arizona's claims, which untimely challenged the 2009 Finding.

Even if Arizona had challenged the district court's jurisdictional holding, that challenge would have no merit because the district court's analysis of the Act's judicial review provision was correct.

The Consent Decree is based upon the premise that EPA had an obligation to promulgate a FIP for Arizona, or approve a SIP, within two years of finding that Arizona "ha[d] failed to make a required submission" under the Regional Haze Rule. *See* 42 U.S.C. § 7410(c)(1)(A); Consent Decree at 2 (Ariz. App. 5). EPA's view, which

[4] The district court also cited the stipulated order establishing the scope of Arizona's intervention in the case, and noted that "to the extent that Arizona presents arguments here beyond the scope of [the] Order, they are not properly before the Court." Op. at 2 (Ariz. App. 17). The district court did not make any specific findings about whether Arizona's merits arguments were beyond the scope of its intervention, however, because it went on to dispose of Arizona's arguments on jurisdictional grounds. *Id.*

it clearly stated in the 2009 Finding itself, is that the 2009 Finding constituted the type of finding contemplated by Section 110(c) of the Act and thus started the two-year clock. *See* 74 Fed. Reg. at 2393 (finding that Arizona has "failed to submit the plan elements" required by two separate provisions of 40 C.F.R. § 51.309, and identifying the legal consequences that flow from that finding). Arizona's principal merits argument in opposition to the Consent Decree is that the 2009 Finding itself is invalid, because a "fail[ure] to make a required submission," which begins the two-year clock, can only mean the failure to submit *any part* of a SIP. *See* Ariz. Br. at 12-13. Because it submitted a partial SIP, admittedly one that did not include all required elements, Ariz. App. 22, Arizona's view is that the 2009 Finding "cannot be considered an incompleteness finding." Ariz Br. at 12.

As the district court found, this argument is essentially "a means of challenging the 2009 Finding made by the EPA" that Arizona had failed to make a required submission within the meaning of Section 110(c). Op. at 3 (Ariz. App. 18). Arizona may believe that, given its prior partial SIP submission, EPA "*could not* make such a finding," Ariz. Br. at 12, but it cannot pretend that EPA *did not* make such a finding. Arizona argues instead that when EPA made that finding, its reasoning or statutory interpretation was invalid.

This argument was available to Arizona at the time of the 2009 Finding itself. As such, Section 307 of the Act provided Arizona with its only opportunity to challenge the 2009 Finding, and the Act required such a challenge to be presented to an appropriate U.S. Court of Appeals within 60 days. *See* 42 U.S.C. § 7607(b)(1). This Court has repeatedly held that the 60-day window in Section 307 is jurisdictional in nature and, as such, it must be strictly construed. *See, e.g.*, *National Mining Ass'n v. U.S. Dep't of Interior*, 70 F.3d 1345, 1350 (D.C. Cir. 1995). Section 307 also does not allow a party to make an untimely challenge to a final, reviewable action by embedding it as a collateral attack within a challenge to a different action. *Id.*; *see State of New York v. EPA*, 852 F.2d 574, 580 n.3 (D.C. Cir. 1988).

The proceedings in this case demonstrate why the 60-day window is important. EPA made a finding in which it expressed its interpretation of the Act, applied that interpretation to factual circumstances for 37 States, and identified the legal consequences that would flow from its finding. Based on that Finding and on EPA's stated deadline, several states submitted SIPs, Plaintiffs filed suit, and EPA agreed to a settlement. The purpose of Section 307(b) is to allow the Courts of Appeals to resolve any disputes about such far-reaching agency actions under the Act soon after they arise. The Act does not allow Arizona to come into district court and challenge a consent decree based on arguments that should have (and could have) been presented to a Court of Appeals more than three years earlier. Even if Arizona had challenged the district court's jurisdiction analysis, therefore, that analysis would have to be affirmed.

C. The interrelated doctrines of ripeness and standing provide an independent basis for the district court to reject Arizona's arguments.

The district court did not only lack jurisdiction under the Act itself to consider Arizona's argument that the Consent Decree is inconsistent with the Act. It also did not have jurisdiction under the "inter-related" doctrines of ripeness and standing. *Worth v. Jackson*, 451 F.3d 854, 855 (D.C. Cir. 2006). Arizona complains that it would be harmed by EPA's promulgation of a FIP. Before EPA promulgates a FIP, such a claim is unripe. Arizona also lacks standing to challenge the Consent Decree on this basis because, if EPA were to promulgate a FIP, reversing the district court's entry of the Consent Decree would not invalidate that FIP.

Ripeness. The Consent Decree sets deadlines for EPA to take certain actions, but those actions might include promulgation of a full or partial FIP *or* full or partial approval of a State SIP submission. *See* Consent Decree ¶ 4 (Ariz. App. 8). In an abstract challenge to the Consent Decree, therefore, Arizona can argue only that EPA *might* exercise its discretion under the Consent Decree in a manner that is inconsistent with the Act. EPA might also meet its Consent Decree obligations by approving Arizona's SIP, as Arizona would prefer. Under these circumstances, the doctrine of prudential ripeness counsels the Court to "refus[e] to exercise jurisdiction," instead "letting the administrative process run its course before binding parties to a judicial decision." *American Petroleum Inst. v. EPA*, 683 F.3d 382, 386 (D.C. Cir. 2012) (citing

Abbott Labs. v. Gardner, 387 U.S. 136, 148 (1967). The purpose of this doctrine is to allow the agency to "solidify or simplify the factual context and narrow the legal issues at play," ensuring that "Article III courts make decisions only when they have to, and then, only once." *Id.* at 387.

Abbott Labs establishes a two-pronged test for determining whether a controversy is prudentially ripe. First, "the fitness of the issues for judicial decision," *Abbott Labs.*, 387 U.S. at 149, is not yet established here. If EPA were to choose to meet its statutory and Consent Decree obligations by approving Arizona's SIP submission, then there would be no controversy. If, on the other hand, EPA were to choose to meet its obligations by promulgating a FIP, Arizona could file a petition for review of that FIP under Section 307 of the Act, 42 U.S.C. § 7607(b). Such a challenge, with a more concrete setting and a full administrative record, would be more fit for judicial decision than Arizona's abstract challenge to the Consent Decree. The availability of such a remedy also satisfies the second prong of the *Abbott Labs* test, the "hardship to the parties" if review is deferred. Arizona does not claim any harm from the Consent Decree itself, but only from the potential promulgation a FIP. Arizona can therefore, without suffering any hardship, wait until a FIP may be promulgated and seek review under Section 307 at that time.

Standing. Arizona might claim that, because EPA promulgated a partial FIP for Arizona in December 2012, its challenge to the Consent Decree is ripe. *See* Ariz. Br.

at 7-8; *supra* p. 11. But the existence of that FIP highlights another jurisdictional obstacle: Arizona lacks standing to challenge the Consent Decree. In order to demonstrate standing to oppose the Consent Decree, Arizona must allege an actual or imminent injury that is fairly traceable to the challenged action and that is redressable by this Court. *See Lujan v. Defenders of Wildlife*, 504 U.S. 555, 560 (1992).[5] Once EPA promulgates a FIP, however, any injury that Arizona suffers as a result of that FIP is not redressable except by direct review of that FIP. It is the Act, and not the Consent Decree, that gives EPA authority to promulgate a FIP. *See* 77 Fed. Reg. at 72,513. The Consent Decree merely establishes deadlines for EPA to exercise that authority. Reversing the district court's entry of the Consent Decree would therefore not invalidate the statutory basis for the FIP.

The Eleventh Circuit reached this conclusion in *Florida Wildlife Fed. v. South Florida Water Mgmt. Dist.*, 647 F.3d 1296, 1305-06 (11th Cir. 2011). In that case, EPA made a formal Determination in 2009 that Florida's water quality standards were inadequate, which "triggered [its] statutory obligation to promptly prepare and publish proposed regulations." *Id.* at 1300. EPA then agreed to a consent decree establishing deadlines for the promulgation of those regulations, and several intervenors objected

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[5] Although the district court granted Arizona the status of an intervenor (for limited purposes) in Plaintiffs' district court action, the appeal here is solely Arizona's. As a result, Arizona must establish its own standing in this Court to challenge entry of the Consent Decree. *See Diamond v. Charles*, 476 U.S. 54, 68 (1986).

to entry of the consent decree. The Eleventh Circuit held that the intervenors' objections were not justiciable because "EPA's power and duty to promulgate" the disputed regulations "come from its determination . . . that Florida's existing standards were inadequate – not from a consent decree." *Id.* at 1306. Thus, reversing the approval of the consent decree would not redress the intervenors' injuries, because the 2009 Determination and the resulting regulations would remain in place.

The similarities between *Florida Wildlife Federation* and the present case are striking. Although the Consent Decree here established deadlines for EPA to act, the agency's underlying duty was triggered by a 2009 Finding that Arizona can no longer challenge, and its authority to promulgate a FIP comes from the Act itself. Reversing the district court might force EPA to litigate Plaintiffs' mandatory duty claim, thus reopening the question of what deadlines should apply, but it would not vacate EPA's December 2012 decision to promulgate a partial FIP. Here, as in *Florida Wildlife Federation*, "[t]he Intervenors had an open door to bring a full challenge to the agency's 2009 Determination . . . the real source of their alleged injuries. They chose instead to challenge a consent decree that did nothing to change the effect of the 2009 Determination." 647 F.3d at 1306. That challenge is therefore nonjusticiable.

The interrelated doctrines of ripeness and standing thus bar Arizona's appeal of the entry of the Consent Decree, but they do not leave Arizona without a remedy. Arizona can avoid any of the harm it alleges from the Consent Decree simply by challenging any FIP that EPA might promulgate. And indeed, Arizona *already has* challenged EPA's authority to promulgate the December 2012 partial FIP in a separate petition for review in the Ninth Circuit. *See State of Arizona v. EPA*, No. 13-70366 (9th Cir.). EPA is aware of four other cases in the Ninth Circuit challenging the same action, brought by parties who have not appealed the entry of the Consent Decree and are not before the Court here. Arizona's arguments about the validity of the partial FIP should be made in its existing case before the Ninth Circuit, to the extent that Section 307 allows, and not obliquely in a challenge to a Consent Decree between EPA and third-party Plaintiffs.

II. THE CONSENT DECREE IS A FAIR AND REASONABLE SETTLEMENT OF PLAINTIFFS' CLEAN AIR ACT CLAIM.

Given the jurisdictional failings of Arizona's claim, there is no need for the Court to consider the argument in Arizona's opening brief that the Consent Decree is inconsistent with the Act. If the Court does reach that question, however, it should conclude that the district court properly exercised its discretion in entering the Consent Decree. The 2009 Finding was consistent with the Act, and the Consent Decree was consistent with both the Act and the 2009 Finding.

Arizona admits that if EPA makes "a finding of failure to submit a regional haze SIP," then it has authority to promulgate a regional haze FIP under Section 110(c). *See* Ariz. Br. at 10 (citing 42 U.S.C. § 7410(c)(1)). As discussed above, Arizona's argument on the merits is that the 2009 Finding did not constitute such a finding, and therefore could not have triggered EPA's duty under Section 110(c) to either approve a State SIP or promulgate a FIP within two years. *See* Ariz. Br. at 9-13.

On its face, the 2009 Finding refutes this assertion. Under the statute, EPA's nondiscretionary duty arises when it finds that "a State has failed to make a required submission." 42 U.S.C. § 7410(c)(1)(A). According to the 2009 Finding, the States listed "have failed to make *all or part* of the required SIP submissions to address regional haze." 74 Fed. Reg. at 2393 (Ariz. App. 26) (emphasis added). Specifically, Arizona had "failed to submit the plan elements required by 40 C.F.R. § 51.309(g)" and had "failed to submit the plan element required by 40 C.F.R. 51.309(d)(4)." *Id.*

Arizona claims that this Finding could be valid only if Arizona had submitted no plan at all, and that if Arizona makes a partial submission of any kind, EPA must evaluate it under Section 110(k)(1)(A), and that "the 2009 Finding does not find that Arizona failed to submit a SIP." *See* Ariz. Br. at 12. This interpretation is contrary to the language of the statute, which does not condition EPA's duty on the failure to submit a SIP, but rather the failure "to make a required submission." 42 U.S.C. § 7410(c)(1)(A). Even if this language contains some ambiguity, it was at least reasonable for EPA to conclude in the 2009 Finding that Arizona had failed to make "a required submission" – that is, the plan elements required by 40 C.F.R § 51.309(g) and 51.309(d)(4). Arizona admitted that, in its 2008 SIP submission, it had not included the elements required by 40 C.F.R. § 51.309(g) or (d)(4). *See* Ariz. App. 22.

The fact that Arizona made additional submissions to EPA after the 2009 Finding was published on January 15, 2009 cannot change the validity of that Finding. EPA's 2009 Finding can only be evaluated based on the record before EPA at the time that it acted, including Arizona's own admission. *See, e.g.*, *American Farm Bureau Fed. v. EPA*, 559 F.3d 512, 521 n.* (D.C. Cir. 2009). The record as it existed in 2009 demonstrated Arizona's failure to submit a required plan element, and thus supported the conclusion that EPA had two years from the date of the Finding to perform its nondiscretionary duties. Arizona may have submitted a supplemental SIP revision to EPA in February 2011, but the Act does not provide that such a submission would stop that two-year clock. To the contrary, Section 110(c) provides that even if the State corrects the deficiency, EPA must approve the State's SIP within two years *of the original finding* or promulgate a FIP. *See* 42 U.S.C. § 7410(c)(1); *see also* Op. at 4 (Ariz. App. 19).

Finally, Arizona claims that if EPA imposes a FIP, it will "depriv[e] Arizona of the right to develop its own pollution control strategy for regional haze." Ariz. Br. at 13; *see generally id.* at 13-16. It is true that, under the Act, Arizona has the primary responsibility to develop a strategy for meeting the air quality objectives that Congress and EPA establish. EPA also does not dispute that, in the first instance, States have the opportunity and the flexibility to evaluate what control technologies are most appropriate for the sources of air pollution within their jurisdiction that contribute to regional haze. But under the Act, States may only take advantage of the benefits of cooperative federalism if they discharge their own responsibilities in a timely manner. In this case, EPA found that as of January 2009, Arizona had failed to fully act upon the 1999 promulgation and the 2005 revision of the Regional Haze Rule. Arizona could have challenged EPA's conclusion in the 2009 Finding, but it did not.

Given that Finding, the Act *requires* EPA to step in and, if necessary, promulgate a FIP that will carry out the Act's purposes. This does not deny Arizona "a reasonable opportunity to address any deficiencies that the EPA identifies." Ariz. Br. at 16. Arizona itself had identified those deficiencies even before making its 2008 SIP submission, *see* Ariz. App. 22, and had a reasonable opportunity to correct them. Instead, it chose to submit a new plan in 2011. The Act and the Consent Decree allow EPA to take action on that SIP submission, but they do not allow EPA to give Arizona unlimited time to conform its SIP to the applicable statutory and regulatory requirements.

Plaintiffs' Complaint in the underlying litigation here was based on a straightforward understanding of Section 110(c) and of the 2009 Finding. That claim was at least colorable, and might have led the district court to impose deadlines on EPA to perform its nondiscretionary duties under Section 110(c)(1). EPA reasonably chose to negotiate a series of deadlines directly with Plaintiffs rather than submit these issues to the district court, and the court reasonably accepted the parties' negotiated resolution. The Consent Decree is fully consistent with the Act and represents a valid settlement of Plaintiffs' claims, and the court therefore did not abuse its discretion in approving it.

CONCLUSION

For the foregoing reasons, the district court's entry of the Consent Decree should be affirmed.

Respectfully submitted,

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CERTIFICATES

Pursuant to Federal Rule of Appellate Procedure 37(a)(7)(C), I certify that the foregoing Brief of Appellee EPA contains 6,790 words, exclusive of front matter and certificates, as counted by the "word count" feature of Microsoft Word.

All counsel in this case are registered to receive electronic service. Copies of the foregoing brief were served upon all counsel by operation of the Court's electronic filing system on February 19, 2013. Hard copies of the brief were also served upon the following counsel by first class mail on February 19, 2013.

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