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October 28, 2009

The Honorable Laura Yoshii
Acting Regional Administrator
U.S. Environmental Protection Agency Region IX
75 Hawthorne Street
San Francisco, California 94105

RE: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advanced Notice of Proposed Rulemaking, Docket No. EPA-R09-OAR-2009-0598

Dear Administrator Yoshii:

Enclosed are the comments of the Central Arizona Water Conservation District (CAWCD) on the above-referenced Advanced Notice of Proposed Rulemaking. CAWCD very much appreciates the opportunity to submit comments on a matter of such critical importance to the Central Arizona Project, its water users and taxpayers.

Sincerely,

/s/

Douglas K. Miller
General Counsel

Enclosure

cc: Anita Lee, U.S. EPA Region IX (w/enclosure)

Comments of the Central Arizona Water Conservation District on the Environmental Protection Agency's Advanced Notice of Proposed Rulemaking Regarding Best Available Retrofit Technology for Nitrogen Oxide Emissions at the Navajo Generating Station

Docket Number EPA-R09-OAR-2009-0598

October 28, 2009

I. Introduction

On August 28, 2009, the Environmental Protection Agency published an Advanced Notice of Proposed Rulemaking (ANPR) on Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology (BART) for Four Corners Power Plant and Navajo Generating Station.[1] The agency gave interested parties thirty days to comment.[2]

The Central Arizona Water Conservation District (CAWCD) is the operating agent of the federally authorized Central Arizona Project (CAP). The CAP is a massive water delivery project, constructed by the United States Bureau of Reclamation under the authority of the Colorado River Basin Project Act of 1968 (the Basin Project Act),[3] to enable Arizona to make full use of its Colorado River entitlement. Reclamation holds rights to 24.3 percent of the net output of the Navajo Generating Station (NGS) for the use and benefit of the Central Arizona Project.

In 1964, the United States Supreme Court confirmed Arizona's right to 2.8 million acre-feet of Colorado River water annually.[4] Until construction of the CAP, however, Arizona had no practical means of putting its full Colorado River entitlement to use, because it lacked a delivery system capable of transporting water from the Colorado River to the rapidly growing regions of central and southern Arizona.

Section 304(b)(1) of the Basin Project Act[5] authorized the Secretary of the Interior (Secretary), in the event he determined it to be necessary to effect repayment of the CAP, to enter into a master contract with an organization having the authority to levy ad valorem taxes to assist in project repayment. The Secretary asked Arizona to form such an organization, and CAWCD was formed in 1971 pursuant to state law.[6] CAWCD is a political subdivision of the State of Arizona. Its service area consists of the State's three most populous counties, all of which are served by the CAP. In 1972, CAWCD entered into a master contract with the Secretary for repayment of CAP costs and delivery of the CAP water supply. That contract was amended in 1988 to increase CAWCD's repayment

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[1] 74 Fed. Reg. 44313-34.

[2] By Federal Register notice of September 30, 2009, the Agency extended the comment period by thirty days, to and including October 28, 2009. 74 Fed. Reg. 50154-55.

[3] Public Law 90-537, 43 U.S.C. §§ 1501, et seq.

[4] Arizona v. California, 376 U.S. 340.

[5] 43 U.S.C. § 1524(b)(1).

[6] A.R.S. §§ 48-3701, et seq.

obligation for the CAP. CAWCD's interest in EPA's on-going BART review for NGS stems from the critical role that NGS plays in the operation of the CAP and in the repayment of CAP costs.

CAWCD understands that the EPA is considering potential modifications to assumptions that were used in the BART analysis submitted by Salt River Project Agricultural Improvement and Power District (SRP) in December 2008.[7] If implemented, these modifications could result in a proposed BART determination that requires installation of selective catalytic reduction (SCR) technology at NGS to control nitrogen oxide (NO_x) emissions.

It is CAWCD's opinion that the analyses performed by industry experts on behalf of NGS owners were done in accordance with accepted practices. SRP's analyses were coordinated and documented with EPA to ensure that appropriate assumptions were used in the BART analyses. SRP's analyses demonstrate that combustion controls alone (low NOx burners and separated overfire air (LNB/SOFA)) produce the greatest share of the visibility benefit. SRP's analyses also demonstrate that little, if any, incremental visibility benefit would be realized at the nearby Class I areas if SCRs were also required. For example, SRP's consultant evaluated the impact on nearby Class I areas of installing and operating LNB/SOFA at a NO_x emission rate of 0.24 pounds per million British thermal units (lb/MBtu).[8] LNB/SOFA produced visibility improvements across the 11 nearby Class I areas averaging 0.37 deciviews (dv). Lowering the NO_x emission rate to 0.20 lb/MBtu for this combustion modification produced visibility improvements across the 11 Class I areas averaging 0.47 dv. SRP's analysis showed that nstalling and operating SCRs in addition to LNB/SOFA would achieve an average incremental visibility improvement of only 0.23 dv – but at an incremental cost of over fifteen times that of LNB/SOFA.[9] Based on this, in 2008 the NGS participants voluntarily approved the capital expenditures necessary for the installation of LNB/SOFA at all three units of NGS. Unit 3 was retrofit with LNB/SOFA during the Spring 2009 maintenance outage. Units 1 and 2 are scheduled to have LNB/SOFA installed in 2011 and 2010, respectively. After the installation and operation of LNB/SOFA on Unit 3, the Unit 3 NO_x emission rate was found to be less than 0.24 lb/MBtu.[10] The measured emission rate was significantly less than the presumptive BART emission level of 0.28 lb/MBtu, and less even than SRP's proposed NO_x emissions limit, and supports the use of combustion controls alone at NGS as the appropriate technology for protecting and improving visibility in nearby Class I areas.

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[7] SRP is both an owner of a 21.7% share in the Plant and the operating agent of the Plant. The other participants are the United States Bureau of Reclamation for CAP (24.3%), Los Angeles Department of Water and Power (21.2%), Nevada Power (11.3%), and Tucson Electric Power (7.5%).

[8] ENSR Corporation, Revised BART Analysis for the Navajo Generating Station Units 1-3, December 2008, EPA-R09-OAR-2009-0598-0010.1.

[9] See Figure 1 herein, p. 30.

[10] The data reported so far indicate that actual NO_x emissions from Unit 3 have been less than 0.24 lb/MBtu on a 30-day rolling average basis. These data may be found at: http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard

Furthermore, the installation and operation of SCRs actually have the potential for *degrading* visibility.[11] EPA has acknowledged in the ANPR that SCR installation increases emissions of acid mists such as H_2SO_4, a pollutant that degrades visibility. As a consequence, the Plant participants may be required to install additional controls, such as reagent injection technology, to convert acid mist gases to particulate matter, which could then be captured by downstream particulate control devices. However, that in turn may require installation of polishing bag houses to mitigate the effect of the sorbent injection and its increased particulate emissions. As a result, an estimated $660 million price tag to add SCR controls could potentially balloon to nearly $1 billion. Given the other risks and uncertainties currently facing NGS, the significantly higher costs of the more stringent control options would call into question the economic viability of the generating station.

II. <u>The Importance of NGS to the CAP and the Regional Economy</u>

The potential loss of NGS has major ramifications for water delivery, Native Americans, and the economy of Arizona.

A. <u>NGS Is Essentially the Sole Source of Power for Pumping Water Through the CAP.</u>

The CAP needs and uses large amounts of energy to pump CAP water, about 95 percent of which is supplied by NGS. The CAP diverts Colorado River water from Lake Havasu, on the Colorado River, and transports it across the desert to central and southern Arizona by means of a 336-mile long water conveyance system that includes 15 pumping plants, concrete-lined canals, inverted siphons, tunnels, pipelines and a regulatory storage reservoir. Since CAP's service area is located "uphill" from the Colorado River, a significant pump lift is required to make deliveries of CAP water to water users, a total lift from beginning to end of over 3,000 feet. The CAP is the largest single source of renewable water supplies in the State of Arizona and the largest single end-user of power in the state.

The CAP uses about 2.8 million megawatt hours of energy to pump about 1.6 million acre-feet of water each year from the Colorado River for delivery to thirsty cities, towns, private water companies, irrigation districts and Indian communities situated throughout its service area.[12] As Congress intended, the importation of Colorado River water through the CAP has reduced dependence on dwindling groundwater resources within CAWCD's service area by providing a stable, renewable supply of water which can and does serve as an alternative to continued pumping of groundwater. Indeed, Arizona law now requires that groundwater withdrawals from the most heavily used groundwater basins be reduced over time and replaced with renewable surface water supplies, much of

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[11] For example, with SCR, the modeled visibility changes at the Grand Canyon showed a degradation in visibility relative to LNB/SOFA of 0.09 dv due to the proximity of the Grand Canyon to NGS and the increased H_2SO_4 emissions to be expected from SCRs.

[12] As part of comments submitted by CAWCD to EPA on July 13, 2009, CAWCD included a detailed Appendix B that showed CAP water deliveries for 2008 to the many water users that depend on the CAP to meet their annual water needs.

which will come from the CAP.[13] CAP water meets about 50 percent of the municipal water demand within CAWCD's service area, which encompasses 80 percent of the state's population. CAP water comprises about 45 percent of the City of Phoenix's total water budget, and by 2020, will meet about 80 percent of the City of Tucson's water demand. Equally important, CAP water is a significant source of water for Native American communities within Arizona: 47 percent of the total CAP supply is dedicated to Native American use. The CAP also delivers water to six underground recharge projects that "bank" water supplies for later recovery during periods of drought. CAWCD and its water users rely implicitly on NGS for the cost effective delivery of these essential water supplies.

B. NGS is Critical to CAWCD's Finances.

NGS power not needed for CAP pumping is sold pursuant to federal law and policy to help repay the construction costs of the CAP and fund the costs of Indian water rights settlements in Arizona. This is authorized specifically by Congress. The Basin Project Act authorized the Secretary of the Interior to dispose of power not needed for CAP pumping and required the Secretary to deposit the revenues from such power sales in the Lower Colorado River Basin Development Fund established under that Act.[14] The Hoover Power Plant Act of 1984 authorized the sale of surplus power from NGS for the specific purpose of assisting in payment and repayment of CAP costs.[15] In 2004, Congress expanded the use of revenues from sales of surplus NGS power by authorizing the use of revenues deposited in the Lower Colorado River Basin Development Fund to help fund the costs of Indian water rights settlements in Arizona after having been applied first against CAWCD's repayment obligation for the CAP.[16] Currently, revenues from the sale of surplus NGS power contribute about $22 million per year toward CAWCD's $57 million annual repayment obligation for the CAP. In the future, revenues from the sale of surplus NGS power are expected to contribute $50 million or more per year toward CAP repayment, revenues that will also be used to help fund the costs of Indian water rights settlements in Arizona. Thus, NGS is critical not only to CAP operations and the ability of CAWCD to meet its water delivery obligations, but also to CAWCD's finances and to the fulfillment of commitments made in numerous Indian water rights settlements to which the United States is a party.[17]

C. NGS is Critical to the Navajo Nation and the Hopi Tribe.

[13] The Arizona Groundwater Management Act, A.R.S. §§ 45-401, et seq., requires significant reductions in groundwater usage in active management areas (AMAs) to achieve "safe-yield" by 2025, including in the Phoenix and Tucson AMAs. Safe-yield is achieved when no more groundwater is withdrawn than is replaced through natural and artificial recharge.

[14] Basin Project Act, Sections 304(b) and 403(c)(1), 43 U.S.C. §§ 1523(b), 1543(c)(1).

[15] See Section 107 of the Hoover Power Plant Act of 1984, Public Law 98-381, 98 Stat. 1333, 1339-1340 (August 17, 1984).

[16] See Section 107 of the Arizona Water Settlements Act of 2004, Public Law 108-451, codified at 43 U.S.C. § 1543(f).

[17] As part of comments submitted by CAWCD to EPA on July 13, 2009, CAWCD included a detailed Appendix A that explained the importance of CAP water in numerous Congressionally approved Indian water rights settlements to which the United States is a party.

NGS is a significant source of employment for the Navajo people. Through an agreement with the Navajo Nation, NGS gives employment preference to Native Americans for all jobs at the generating station. NGS currently provides employment for about 545 full-time workers, almost 80 percent of whom are Native Americans. In addition, hundreds of Native Americans are employed at the station on a part-time basis during maintenance activities. The Kayenta Coal Mine, which is the sole source of fuel for the Navajo Generating Station, provides 415 jobs, 90 percent of which are held by Native Americans. The Navajo Nation and the Hopi Tribe also receive significant revenues from payments associated with coal royalties, taxes, permits, lease fees, and scholarships from NGS and the Kayenta Coal Mine. In 2009, the station and the mine are expected to contribute almost $140 million in revenue and wages to the Navajo Nation and its tribal members.

Table 1 – Benefits to the Navajo Nation

(2009)

Wages – Plant	$51.4	Million
Wages – Mine	44.4	
Coal Royalties – Mine	23.9	
Electricity (NTUA) – Plant and Mine	12.6	
Annual Lump Sum Payment – Mine	3.5	
Site Lease – Plant	0.6	
Air Permit – Plant	0.4	
Scholarships / Donations	0.4	
Navajo Way – Plant and Mine	0.1	
TOTAL	$137.30	Million

Payments to the Hopi Tribe will total about $12 million in 2009. While smaller in amount than the revenues received by the Navajo Nation, the revenues received by the Hopi Tribe from coal sales make up the bulk of what the Hopi Tribe needs and uses each year for its governmental operations.

D. NGS Is a Major Contributor to the Economy of Northern Arizona.

NGS is the largest employer in its area, with an annual payroll and benefits of $52 million. NGS and its employees are active in local communities, contributing funds and volunteering time to improve the quality of life in the area. The station regularly provides financial support for various community efforts in the city of Page and surrounding Navajo communities. Examples include a gift from NGS to construct the Technology Center at the Page campus of Coconino Community College and a contribution to the LeChee Chapter of the Navajo Nation for the LeChee Senior Citizen Center. NGS also offers college scholarships to students in Page as well as students across the Navajo Nation.

E. Summary and Conclusions.

The importance of this matter cannot be overstated. EPA is not free to require controls for NO_x at NGS that cannot be shown to be cost beneficial. Nor should it take any action that could place the future of NGS in jeopardy. The Clean Air Act and the Agency's

Regional Haze rules permit the Agency to take a reasonable, measured approach to controlling NO_x emissions at NGS, one that protects visibility at nearby Class I areas while avoiding a result that could jeopardize the long term operation of NGS.

III. Discussion

A. Background and Legal Context

(1) The relationship of BART to the broader "reasonable progress" program.

As the Clean Air Act (CAA) and the case law make clear, BART is only one part of the reasonable progress program, which addresses contributions to visibility impairment from many types of sources, including mobile sources, fires, and the like. Even for BART-eligible sources, the regional haze program is designed to permit consideration of additional controls (beyond BART) in future planning periods if such controls are determined at that time to be needed to make reasonable progress toward the national visibility goal.

EPA's visibility program is not restricted to identifying and requiring BART for stationary sources. To the contrary, the Clean Air Act and EPA's regional haze rules treat BART as a part of the larger "reasonable progress" requirement.[18] That overarching requirement in turn is intended to promote the national goal of preventing and remedying visibility impairment in mandatory federal Class I areas by 2064 to the extent that impairment results from anthropogenic air pollution.[19] Accordingly, EPA's regional haze rules expressly require periodic reassessment of whether, and to what extent, any additional emission reductions are needed to continue to achieve reasonable progress toward the national goal.[20] Adherence to its own BART rules compels EPA to conclude that BART requirements for NGS are satisfied by low NO_x burners and separated overfire air for NO_x and the Plant's existing controls for particulate matter. Any questions regarding whether yet more controls are necessary and warranted should be considered in future stages of the program. Those questions would and should be addressed then, in the larger context of the many sources of regional haze impairment affecting the Colorado Plateau, including, for example, mobile sources, prescribed and uncontrolled fires, and the ongoing regional planning efforts to address haze in the Western states.[21]

(2) The presumptive NO_x limits.

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[18] See Clean Air Act (CAA), § 169A(b)(2); Utility Air Regulatory Group v. EPA, 471 F.3d 1333, 1340-41 (D.C. Cir. 2006); Ctr. for Energy & Econ. Dev. v. EPA, 398 F.3d 653, 660 (D.C. Cir. 2005).

[19] CAA § 169A(a)(1).

[20] 40 C.F.R. § 51.308(d), (f), (g), (h); EPA, Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, at page 1-2 (June 1, 2007) (explaining that reasonable progress goals "are interim goals that represent incremental visibility improvement over time toward the goal of natural background [visibility] conditions").

[21] See, e.g., 40 C.F.R. § 51.308(d)(3)(v)(E), (G) (providing that development of long-term strategies for regional haze must include consideration of, inter alia, "[s]moke management techniques for agricultural and forestry management" and effects on visibility from "point, area, and mobile source emissions").

EPA's own BART Guidelines for electrical generating units (EGUs) establish presumptive limits for NO_x that reflect the use of combustion controls only (except for cyclones). The participants in NGS are prepared to meet the presumptive limits with combustion controls. Indeed, they are voluntarily installing such controls at this very moment. EPA's analytical basis for adopting the presumptive limits, and the nature of the BART Guidelines as rules that are binding on EPA, mean that EPA would have to establish an overwhelmingly compelling case that application of the BART factors requires a departure from the presumptive limits, based on case-specific circumstances, before it could require SCRs as BART for NO_x at NGS.

The BART rules specify that coal-fired utility boilers of greater than 200 MW at power plants of greater than 750 MW generally should be required to meet the presumptive NO_x emission limits listed for specific boiler types in Table 1 of the BART Guidelines,[22] rather than less stringent or more stringent limits: "You should require such utility boilers to meet the following [presumptive] NO_x emissions limits, unless you determine that an alternative control level is justified based on consideration of the statutory factors."[23] Moreover, EPA stated in establishing the presumptive limits that it "believe[s] that [the presumptive limits] are *extremely likely to be appropriate* for all greater than 750 MW power plants subject to BART."[24] EPA determined that the presumptive limits "reflect highly cost-effective technologies,"[25] and, pursuant to its authority to establish guidelines for BART determinations for large power plants in CAA § 169A(b)(2), based this conclusion on its own analysis of appropriate limits for electric generating units (EGUs):

> Based on our analysis of emissions from power plants, we believe that applying these highly cost-effective controls at the large power plants covered by the guidelines would result in significant improvements in visibility and help to ensure reasonable progress toward the national visibility goal.[26]

EPA reiterated this point in the preamble to its final BART Alternatives Rule:

> We determined in the BART final rule that the limits represented by the presumptions are cost effective for large EGUs at the largest power plants. *We believe that the presumptions represent a reasonable estimate of a stringent case BART . . ..*
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> . . . In the final BART guidelines establishing the presumptions, EPA took into account the degree of improvement in visibility that would result from the installation of the presumptive level of controls in finding that such

[22] Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, 70 Fed. Reg. 39104, 39172 (July 6, 2005).

[23] Id. at 39171 col. 3.

[24] Id. at 39131 col. 3 (emphasis added).

[25] Id. at col. 2.

[26] Id. at col. 3; see also, id. (noting that, even for those above-200-MW units that are located at power plants below 750 MW, the presumptive limits likely will represent BART because they generally are highly cost-effective and will "result in a significant degree of visibility improvement").

> controls should generally be found to be BART. As explained in the preamble to the BART guidelines, controlling the type of sources covered by the presumptions at the level of the presumptive standards is likely to result in a substantial degree of visibility improvement based on EPA's modeling analyses.[27]

Describing its presumptive-BART analysis,[28] EPA concluded that, except for cyclone units, combustion controls are "more cost-effective than post-combustion controls such as SCRs."[29]

The BART rules' presumptive limits for NO_x are premised on EPA's determination that "[m]ost EGUs can meet these presumptive NO_x limits through the use of current combustion control technology, *i.e.*, the careful control of combustion air and low-NO_x burners."[30] Tellingly, in addressing possible individual cases in which a facility is *unable* to meet its presumptive limit with "current combustion control technology," the rules recommend consideration of "whether *advanced combustion control technologies* such as rotating opposed fire air should be used to meet these limits."[31] The rules conspicuously omit any direction or even suggestion that post-combustion controls be considered, let alone required as BART. Indeed, with two limited exceptions, the rules make no mention of post-combustion NO_x controls at all. Those two narrow exceptions concern: (1) cyclone units, for which SCR is the basis for presumptive controls due to those units' unusually high uncontrolled NO_x emission rates; and (2) units that already have post-combustion controls installed and in use for at least part of the year, for which year-round use of those controls is presumptively BART.[32] These exceptions prove the rule: NO_x BART emission limits are to be based on combustion – not post-combustion – controls.[33]

This part of the BART rules reflects a key principle that applies here: In determining NO_x BART for coal-fired EGUs above 200 MW at power plants above 750 MW (other than cyclone units and units that already have post-combustion controls), the control options that must be considered as candidates for BART are those that are necessary to achieve the presumptive limit. Thus, for example, where current combustion control technology is *inadequate* to meet the presumptive limit, the BART assessment is to

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[27] 71 Fed. Reg. 60612, 60619 cols. 1-2 (Oct. 13, 2006).

[28] 70 Fed. Reg. at 39134-35.

[29] Id. at 39134 col. 1.

[30] Id. at 39172 col. 1.

[31] Id. (emphasis added).

[32] See id. at 39171 col. 3, 39172 col. 1; see also id. at 39136 col. 1 ("For [non-cyclone] units, we are not establishing presumptive limits based on the installation of SCR. Although States may in specific cases find that the use of SCR is appropriate, we have not determined that SCR is generally cost-effective for BART across unit types.").

[33] Although some aspects of EPA's BART rules were challenged in the U.S. Court of Appeals for the D.C. Circuit, see Utility Air Regulatory Group v. EPA, 471 F.3d 1333, 1340-41 (D.C. Cir. 2006) (affirming the rule against challenges by an environmental organization and two industry organizations), no one challenged the presumptive emission limits. Thus, the Clean Air Act precludes any challenge to the validity of the presumptive limits. CAA § 307(b)(2), (e).

examine whether advanced combustion controls will meet that limit. If current (or, if necessary, advanced) combustion controls *will* meet the presumptive limit, there is, by definition, an exceedingly strong presumption that post-combustion controls are *not* BART. If that were not the case, then there would have been no point to EPA's establishment of presumptive limits based on its analysis and determination that combustion controls are BART.

In short, anyone arguing that NO_x BART for non-cyclone units should be based on post-combustion controls must bear an especially heavy burden of proof to overcome the presumption – established through notice-and-comment rulemaking – that BART is combustion controls only. That burden is even heavier here, where SRP has shown that EPA's presumptive limits can be met with use of combustion controls alone.

Baseline NO_x emissions for Units 1, 2, and 3 at NGS are 0.49, 0.45, and 0.46 lb/MBtu, respectively. The presumptive NO_x emissions level for these units is 0.28 lb/MBtu. SRP found that LNB/SOFA will reduce NO_x emissions from each of the three units to 0.24 lb/MBtu – well below the presumptive NO_x emissions limit of 0.28 lb/MBtu. LNB/SOFA are well known in the industry for reducing NO_x emissions levels to 0.20 lb/MBtu and below. Some units have reduced their emissions to less than 0.12 lb/MBtu, depending on the fuel being burned. With time, experience, and optimization of the LNB/SOFA system, SRP may be able to reduce NO_x emission levels to 0.20 lb/MBtu, thus reducing overall NO_x emissions by an estimated 4,000 tons per year below the 0.24 lb/MBtu emissions level predicted by SRP. It should go without saying that the BART emission limit for NGS should (indeed, must) be based on the installation and operation of LNB/SOFA alone.

(3) Consideration of site-specific factors in applying the cost factor

Under EPA's BART Guidelines, EPA must consider site-specific factors that affect cost calculations. The ANPR appears to be dismissive of such site-specific factors. EPA in its BART determination must give proper weight to them if it is to comply with its own rules.

In applying the BART cost factor in a BART determination for a given facility, site-specific factors that influence control costs must be considered. That principle is reflected in the D.C. Circuit's *American Corn Growers* decision, where the court observed that costs and other factors in a BART determination must be addressed "on a source-by-source basis."[34] That principle is reflected also in EPA's BART rules, which state, for example, that "one or more of the available control options may be eliminated from consideration because they are demonstrated to be technically infeasible or to have unacceptable energy, cost, or non-air quality environmental impacts on a case-by-case (or site-specific) basis."[35] Moreover, while EPA requires the BART determination to take into account relevant information in "referenced source[s]" "such as" the OAQPS Control Cost Manual, "[t]he cost analysis should also take into account any site-specific design or other conditions . . . that affect the cost of a particular BART technology option" at a given facility.[36] Thus, although the Control Cost Manual may serve as a

[34] Am. Corn Growers Ass'n v. EPA, 291 F.3d 1, 6 (D.C. Cir. 2002).

[35] 70 Fed. Reg. at 39164 col. 2.

[36] Id. at 39166 col. 3.

starting point for control cost estimates, it is by no means determinative. To the contrary, the BART determination should take into account:

> . . . additional information . . . used for the cost calculations, including any information supplied by vendors that affects . . . assumptions regarding purchased equipment costs, equipment life, replacement of major components, and any other element of the calculation that differs from the *Control Cost Manual*.[37]

EPA explained this aspect of the rules in the preamble, emphasizing that the rules permit "flexibility" in which elements of costs to include and in the choice of methodology for calculating costs:

> We believe that the Control Cost Manual provides a good reference tool for cost calculations, but if there are *[cost] elements* or sources *that are not addressed by the Control Cost Manual* or there are *additional cost methods that could be used*, we believe that these could serve as useful supplemental information.[38]

Thus, it is contrary to EPA's own rules to suggest, as the ANPR does,[39] that the Control Cost Manual is in some way binding, that cost elements not included in the Control Cost Manual may not properly be considered in a BART determination, and that no cost estimation methods other than those found in the Control Cost Manual are permitted for BART analyses. It would, moreover, be inconsistent with the statutory scheme and the *American Corn Growers* decision to preclude consideration of costs that relate to site-specific factors even where the costs do not necessarily align with those in general reference sources such as the Control Cost Manual. In developing its proposed BART determinations, therefore, EPA must avoid limitations – whether explicit or implicit – on consideration of site-specific cost factors or use of alternative or supplemental cost calculation methods.

(4) Economic effects of the BART determination.

The BART Guidelines, reinforced by EPA's Reasonable Progress Guidance, make clear that economic effects of the BART determination – including effects not only on the facility and its operations but also on the industry and/or the community in which the facility is located – may properly be considered in determining BART.

Broad economic effects of the selection of BART for a given facility may properly be considered in making the BART determination. The BART rules note, for instance, that collateral economic effects of a BART determination – such as the elimination of the jobs of Navajo and other employees at NGS and the Kayenta Coal Mine that could result from a selection of SCR as BART – may be considered in applying the "energy . . . impacts of

[37] Id. at n.15.

[38] Id. at 39127 col. 2 (emphases added).

[39] See, e.g., 74 Fed. Reg. at 44318, 44320, 44322.

compliance" BART factor under CAA § 169A(g)(2).[40] Similarly, in describing the cost of compliance factor, EPA's guidance for setting reasonable progress goals under the regional haze program notes that "the cost of compliance factor can be interpreted to encompass the cost of compliance for individual sources or source categories, and more broadly the implication of compliance costs to the health and vitality of industries within a state."[41]

(5) Remaining useful life.

The CAA and EPA's BART rules make clear that the remaining useful life of the facility must be considered in determining BART emission limitations for that facility.[42] For BART analysis purposes, a facility's remaining useful life is "the difference between . . . [t]he date that controls will be put in place . . . and . . . [t]he date the facility permanently stops operations."[43] In the case of a source whose "remaining useful life will clearly exceed [the normal amortization] time period" for the control technology being evaluated, "the remaining useful life has essentially no effect on control costs and the BART determination process."[44] On the other hand, if the facility is, for whatever reason, not expected to continue operating until at least the end of the normal amortization period, then the BART-determining authority must take that fact into account in evaluating BART control options and determining BART for that facility.[45]

Here, SRP conservatively used a 20-year amortization period for estimating the cost of SCR and other BART NO_x control options, reflecting, for purposes of the BART cost analysis, the standard amortization period for NO_x control devices in EPA's OAQPS Control Cost Manual.[46] For the reasons discussed in these comments and in SRP's BART analysis, SCR technology is plainly not cost-effective given the marginal visibility benefit that would be realized, and therefore cannot be BART, even when the normal 20-year amortization period is assumed. It follows that SCR would be even more cost-ineffective – and even more plainly ineligible to be BART for the Plant – if a shorter amortization period were assumed.

[40] See 70 Fed. Reg. at 39169 col. 1 ("[T]he energy impacts analysis may consider whether there are relative differences between alternatives regarding the use of locally or regionally available coal, and whether a given alternative would result in significant economic disruption or unemployment.").

[41] EPA, Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, at page 5-1 (June 1, 2007).

[42] See CAA § 169A(g)(2) ("in determining best available retrofit technology the State (or the Administrator in determining emission limitations which reflect such technology) shall take into consideration [*inter alia*] the costs of compliance [and] . . . the remaining useful life of the source"); 40 C.F.R. § 51.301 (defining "BART" and providing that a BART "emission limitation must be established, on a case-by-case basis, taking into consideration [*inter alia*] . . . the costs of compliance . . . [and] the remaining useful life of the source"); *see also* 70 Fed. Reg. at 39166 col. 2, 39169 col. 3-39170 col. 1.

[43] Id. at 39169 col. 3.

[44] Id.

[45] Id.

[46] See 74 Fed. Reg. at 44334 col. 1; Control Cost Manual at 2-48 ("An economic lifetime of 20 years is assumed for the SCR system.").

As noted above, EPA's BART rules explain that the normal amortization period – here, 20 years – is appropriate in applying the remaining-useful-life BART factor "[i]f the [plant's] remaining useful life will *clearly* exceed" that amortization period.[47] Thus, to the extent it is unclear whether the facility will operate until the end of that period, consideration should properly be given to the use, for purposes of the BART analysis, of an assumption of a shorter useful life.

It is far from clear at this time that the Plant, or all units at the Plant, will in fact continue operating for as long as 20 years beyond the commencement date for BART controls. If one assumes that EPA will take final action approving a federal implementation plan for BART for the Plant in 2010, BART controls presumably would have to be installed by 2015.[48] Thus, the normal amortization period would extend to the year 2035. That poses the question whether one can confidently state that the Plant will be operating in 2035. A number of significant factors create substantial uncertainty about whether it will.

First, the current term of the Plant's lease and right-of-way agreements with the Navajo Nation and the Section 323 Grants from the Secretary of the Interior that are necessary for the Plant's continued operation currently are due to expire in 2019 and have not yet been renewed or extended. If they are not renewed or extended, the remaining useful life of the Plant, beginning in the assumed control installation year of 2015, would effectively be as little as 4 years. Under no circumstances could SCR even arguably satisfy the BART determination factors if such a short useful life were applied.

Second, while the term of the existing coal contract with Peabody Energy was most recently extended to 2019, certain other terms and conditions of that contract must be renegotiated and the contract must be further extended beyond 2019. SRP as Plant operator is actively pursuing such negotiations, but it is unclear when those negotiations will be successfully concluded.

Third, because of restrictions imposed by California regulatory agencies on new investment in coal-fired power plants, one of the most significant participants in the Plant by percentage of entitlement to Plant output (21.2 percent), Los Angeles Department of Water and Power, has indicated its intention to withdraw from or dispose of its interest in the Plant by 2020.[49] This presents yet another significant uncertainty for the remaining Plant participants that has the potential to affect the Plant's remaining useful life.

Fourth, the prospect of carbon dioxide emission control regulation, either under new federal legislation or under the existing CAA, creates enormous uncertainty about how the Plant will remain economically viable. Indeed, the likelihood of such regulation

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[47] 70 Fed. Reg. at 39169 col. 3 (emphasis added).

[48] 40 C.F.R. § 51.308(e)(1)(iv) (providing that BART is to be installed and operated beginning 5 years after approval of the BART implementation plan provision).

[49] See, e.g., Bernie Woodall, "Los Angeles Will End Use of Coal-Fired Power," Reuters, July 2, 2009, available at http://www.reuters.com/article/GCA-GreenBusiness/idUSTRE56165X20090702. This article reports that Los Angeles will eliminate the use of electricity generated from coal combustion by 2020, and that Deputy Los Angeles Mayor David Freeman said that the Los Angeles Department of Water and Power will continue to use power from the coal-fired 2,250-megawatt Navajo Generating Station in Arizona until 2019 when its current contract expires.

seems to have increased in recent months, with the House of Representatives' June 2009 passage of climate change legislation, focused in large part on power plant emissions;[50] EPA's April 2009 proposal of an "endangerment" finding under the CAA for carbon dioxide emissions from motor vehicles;[51] and the Agency's September 2009 proposal to adopt the first CAA carbon dioxide emission control regulations for motor vehicles,[52] an action that, when made final, may pave the way for some type of CAA regulatory control on power plants' carbon dioxide emissions. Indeed, EPA has already announced (on September 30, 2009) a proposed "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" that proposes new thresholds for greenhouse gas emissions to define when CAA permits under the New Source Review and Title V operating permits programs would be required for new industrial facilities (including power plants) or upon a major modification of an existing facility.[53] On that same date, Senators Boxer and Kerry introduced climate change legislation in the Senate.[54] Although the prospect of carbon dioxide regulation is quite real, the nature and stringency of any such regulation, the required control technology, the costs of controls and the potential impacts on Plant output are unknown at this time.[55] In summary, the effects on the Plant cannot be predicted with any degree of certainty, but likely would be substantial and may jeopardize the Plant's continued operation well before the 2035 expiration date of the standard 20-year amortization period.

Fifth, other prospective CAA regulations add to the difficulty of predicting the Plant's remaining useful life at this time. EPA has recently initiated proceedings to develop

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[50] American Clean Energy and Security Act of 2009, H.R. 2454, 111th Cong. (2009) (agreed to by House June 26, 2009).

[51] EPA, Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act, 74 Fed. Reg. 18886 (Apr. 24, 2009).

[52] EPA & U.S. Dep't of Transp., Proposed Rulemaking to Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards: Proposed Rule, 74 Fed. Reg. 49454 (Sept. 28, 2009).

[53] http://www.epa.gov/nsr/documents/GHGTailoringProposal.pdf

[54] Clean Energy Jobs and American Power Act, S. 1733, 111th Cong. (2009) (introduced Sept. 30, 2009).

[55] At the present time, the leading technology for capturing carbon dioxide (CO_2) from coal-fired facilities is the absorption of CO_2 from the flue gas path using an absorption/stripping system with aqueous monoethanolamine (MEA). This process was originally developed for the sweetening of natural gas. The operating principles for the separation of CO_2 from a coal-fired power plant flue gas stream would be similar to natural gas treatment. The main drawback of the MEA system is the impact on the unit efficiency. Currently, the installation of the absorption/stripping system is estimated to require upwards of 30 percent of the total power produced by the facility. This high auxiliary power requirement is due to the steam that is required to heat the CO_2 rich MEA to drive off the CO_2. This auxiliary electric requirement will pose serious concerns for the future of a traditional coal-fired generating unit. Additionally, the MEA reagent reacts preferentially with acid gases such as sulfur dioxide, sulfur trioxide, nitrogen oxides, hydrogen chloride, and hydrogen fluoride to form heat-stable salts that are not regenerated upon heating the MEA in the stripper. The consumption of the reagent by the formation of heat-stable salts greatly increases the operational cost of the technology. Therefore, in order to use carbon capture technology efficiently, costly enhancements to exiting air pollution controls (beyond BART) may be required to further reduce these other pollutants in the flue gas prior to the use of carbon capture technology.

Maximum Achievable Control Technology standards for existing power plants under section 112 of the CAA. Those standards are widely expected to impose very stringent control limits for mercury emissions and very possibly emissions of a range of other substances listed under section 112. Again, the effects on the Plant cannot be determined with confidence at this time but could be very substantial and may call into question whether the Plant, or all its units, would continue to operate until as late as 2035, even apart from the other factors described above.

The Plant participants are intelligent, thoughtful, and diligent owners and operators, and CAWCD has no doubt that they will do their best to cope with these challenges and to renew or renegotiate the agreements necessary to ensure the Plant's long-term operation. That they have every intention of doing so is evidenced by their decision voluntarily to invest tens of millions of dollars to install LNB/SOFA at NGS to reduce NO_x emissions. However, some of the challenges faced by the Plant participants are beyond their control and the others require the cooperation or assent of others. As a consequence, a compelling case can be made that a 20-year useful life, beginning in 2015, is an inappropriate assumption for a BART analysis for the Plant. The year 2019 has taken on special significance in this context. At a minimum, an alternative analysis, with a much shorter assumed useful life for the Plant, should be prepared. If installation of the more expensive control technology were required to be completed by 2015, the available amortization period for the required control technology could be as little as four years. If a four-year amortization period were used in the BART analysis, SCR would be shown to be even more cost-ineffective, and even more clearly disqualified as a BART technology, than under the 20-year useful life assumption applied by SRP in its original BART assessment.

Finally, one factor that should *not* be allowed to shorten the useful life of the Plant under the BART program is the choice of BART itself. If, for example, a control technology would be so expensive that an emission limitation effectively compelling its installation and operation would make the facility's continued operation uneconomic, and thus shorten the useful life it otherwise would have, then that control technology is by definition not cost-effective and could not be BART for the facility. EPA's BART rules explain that, in the BART review,

> "one or more of the available control options *may be eliminated from consideration* because they are demonstrated to be technically infeasible or to have unacceptable energy, *cost*, or non-air quality environmental impacts on a case-by-case (or site-specific) basis."[56]

Moreover, BART is not "a requirement to redesign the source when considering available control alternatives."[57] It necessarily follows that BART is not a requirement that would result in shutting the source down altogether.[58]

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[56] 70 Fed. Reg. at 39164 col. 2 (emphasis added).

[57] Id.

[58] See also id. at 39171 col. 1 (addressing cases where, even if a BART control option might otherwise be considered cost-effective, "the installation of controls would affect the viability of continued plant operations" or otherwise would "have a severe impact on plant operations").

B. Specific Comments on the ANPR

CAWCD has reviewed the ANPR carefully and offers the following specific comments.

(1) The costs of controls.

(a) The cost estimates developed by SRP are credible and are supported by a sound engineering estimate.

After reviewing the ANPR and the referenced data supplied with the ANPR, CAWCD has reached the conclusion that the BART analysis (and the SCR cost analysis in particular) completed by SRP was done prudently and in accordance with the BART guidelines and provides an accurate estimate of the costs of installing SCRs at NGS.

SRP hired an engineering firm, Sargent and Lundy (S&L), to perform an analysis of the costs of installing SCRs at NGS. S&L carefully reviewed the potential constructability of SCRs at NGS. S&L is an engineering firm that routinely develops cost estimates for, and participates in, development of retrofit SCR projects.

(b) If anything, the cost estimates for addition of SCR controls at PGE's Boardman Power Plant indicate that the SRP estimates for SCR costs may be conservatively low.

The Oregon Department of Environmental Quality (Oregon DEQ) issued a decision on June 19, 2009, that would require Portland General Electric (PGE) to install SCR at its 585 MW Boardman Power Plant. In its Fiscal Impact Report describing the costs of the BART requirements at the Boardman plant[59] the Oregon DEQ indicates that the costs at Boardman (in 2007 dollars) would incrementally increase from $279.4 million to $470.8 million if SCR were added. If the additional cost of $191.4 million is divided by Boardman's capacity of 585 MW, the cost per MW is $0.3272 million. If that same cost factor is applied to NGS's 2,250 MW of nominal capacity, the costs of installing SCRs at NGS can be estimated to be $736.2 million. This figure would need to be adjusted upward to current dollars and for the extreme remoteness of NGS. This makes SRP's estimates look quite reasonable and, indeed, conservatively low.

(c) The cost estimates developed by the National Park Service (NPS) are entitled to no weight whatsoever.

The ANPR states that the NPS developed a separate cost estimate for installing SCRs at NGS. The NPS estimate purports to show that the costs of installing SCRs at NGS are less than the costs developed by SRP, and that SCRs are much more "cost effective" (i.e., have a lower cost on a $/ton basis) than shown by SRP. The NPS cost estimate is not a valid or accurate estimate of the costs required to install SCRs at NGS and should play no part in this rulemaking. The NPS estimate suffers from the following fatal defects.

(i) The NPS lacks the technical and engineering expertise necessary to develop credible cost estimates.

[59] http://www.deq.state.or.us/aq/haze/docs/FiscalImpactReport.pdf

The National Park Service has never built, procured, engineered, designed or constructed an SCR. That is why the NPS relies exclusively on the outdated OAQPS Control Cost Manual to develop cost estimates for SCR systems for Units 1, 2 and 3 at NGS. As discussed above, while the BART Guidelines[60] suggest that the Control Cost Manual be utilized, it also states that any additional costs not addressed by the manual should be documented and included. The following excerpts from the BART Guidelines support the use of additional representative data:

> We believe that the Control Cost Manual provides a good reference tool for cost calculations, but if there are [cost] elements or sources that are not addressed by the Control Cost Manual or there are additional cost methods that could be used, we believe that these could serve as useful supplemental information.[61]
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> Once the control technology alternatives and achievable emissions performance levels have been identified, you then develop estimates of capital and annual costs. The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the OAQPS Control Cost Manual, Fifth Edition, February 1996, EPA 453/B–96–001). . . . You should include documentation for any additional information you used for the cost calculations, including any information supplied by vendors that affects your assumptions regarding purchased equipment costs, equipment life, replacement of major components, and any other element of the calculation that differs from the Control Cost Manual. . . . The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option.[62]

Thus, the Control Cost Manual acknowledges the propriety of relying on additional representative data when estimating costs in a site-specific context.

(ii) The Control Cost Manual is outdated, flawed and inadequate for the development of cost estimates without adjustments based on engineering experience.

First, the Control Cost Manual is outdated. It was initially developed in 1994. The most recent revision is the EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, dated January 2002. There have been significant cost increases in air quality control (AQC) equipment since its release. Section 4.2, Chapter 2, Selective Catalytic Reduction, was written in October 2000. On page 2-40, Article 2.4 of the SCR section, it states that the costs presented in the manual are based on 1998 dollars.

In Chapter 2 of the Introduction (Article 2.4.3), the Control Cost Manual specifically discusses the importance of escalating the cost of equipment to the current year. Costs

[60] 70 Fed. Reg. 39104.

[61] Id. at 39127.

[62] Id. at 39166 & n. 15.

can and do change dramatically over time. It has been nine years since the SCR section of the Control Cost Manual was written, and the reference costs in the Control Cost Manual are 11 years old. In that time, the AQC industry and the energy industry have seen significant increases in the cost of equipment and construction. The Control Cost Manual does not take into account the significant increase in demand for equipment, commodities, contractors, and construction labor experienced over the past 11 years from the many air pollution control installations associated with: the Acid Rain Program, the NO_x state implementation plan (SIP) call, the New Source Review (NSR) and Prevention of Significant Deterioration (PSD) programs (for both new sources and major modifications to existing sources), the Clean Air Interstate Rule (CAIR), the BART program, and new coal projects in the U.S. and international markets. Any cost estimate must take into account the impact of escalation.

Second, the Control Cost Manual is woefully inadequate for estimating the costs of a retrofit project. The Control Cost Manual was developed principally for use in developing costs associated with a Best Available Control Technology (BACT) requirement for new or modified sources under the NSR and PSD programs. Although it pays lip-service to the issues resulting from retrofit work, it provides no quantitative guidance to develop retrofit costs. It does not take into account retrofit construction difficulties, impacts on balance of plant systems, whether existing equipment requires removal or relocation, or whether such equipment additions are feasible. Site-specific issues, in particular, significantly affect the costs of retrofit SCR systems, because these systems are usually located in tight quarters, near the existing boiler area, requiring extensive modifications to existing ductwork and potentially other equipment. The Control Cost Manual does not address any of these issues and only provides estimating methods for the main SCR process equipment. Unless NPS visited the site and hired an experienced and properly qualified engineer to perform a site assessment to determine the specific needs at this Plant, NPS's cost estimate could not properly account for the true cost of installing SCR at NGS. For example, the Control Cost Manual does not account for costs associated with the following, which are often required on retrofit SCR projects:

- <u>Fan and Draft Modifications</u> – Most SCR projects require modifications to the draft system to overcome the additional pressure loss associated with the SCR system. Many projects have also required upgrades to the boiler or electrostatic precipitators (ESPs) to handle increased pressure or increased vacuum resulting from the SCR.

- <u>Electrical Upgrades</u> – Upgrades are often required to the electrical systems to incorporate the new SCR equipment into the existing system. Depending on the needed fan modifications, these upgrades often including adding a new transformer, switchgear, and additional fire protection equipment.

- <u>Instrumentation and Control System</u> – The control of the SCR needs to be incorporated into the existing plant control system. This is a typical requirement for an SCR system retrofit but would not be needed for a new unit SCR because the SCR would simply be included in the original digital control systems (DCS).

- <u>Air Preheater Modifications</u> – The air heaters typically need to be modified to make them resistant to ammonium bisulfate (ABS) corrosion and plugging.

- Relocation of Existing Equipment – SCR systems often require the relocation of existing plant equipment to make room for the new SCR equipment. This cost can be significant or it can be minor, depending on the project.
- Construction Management – This item is applicable to both new units and retrofit units. However, with new units, the costs of construction management are difficult to identify and segregate because the AQC systems are a portion of the overall project. However, on an AQC retrofit project, all construction management expenses are attributable specifically to the AQC retrofit. Construction management costs include the cost for engineering support, construction, environmental services, secretarial services, safety personnel, quality assurance personnel, drug testing, and other services required to ensure that the construction is performed in accordance with the scope of work, safe work practices, regulatory requirements, construction instructions, construction drawings, and vendor requirements.

Third, there are significant costs items that are simply not included in the Control Cost Manual. These costs include the following:

- NO_x Monitoring System – A NO_x monitoring system is required to measure NO_x before and after the catalyst and is an essential part of the SCR system.
- Gross Receipt Tax – EPA's own CUECost program includes gross receipt tax as a standard line item in the cost estimate.
- Freight – EPA's CUECost program includes freight as a standard line item in the cost estimate. At NGS, freight costs are substantially higher than average due to the extremely remote location of the Plant. There is no rail access for deliveries to the Plant.
- Owner Costs – Owner's costs include items such as staff for site coordination during construction, equipment receiving, contract management, interface with regulatory agencies, and owner engineering costs.
- Construction Indirects – Cost items included in construction indirects include construction equipment, construction contractor overhead and profit, tools, site trailers and utilities, construction supervision, and construction contractor administrative support. Other costs are attributable to the remote location of NGS, which is near Page, Arizona, nearly 140 road miles from the closest substantial population center at Flagstaff. The only access to the Plant is by highway, most of which is 2-lane and narrow and has significant grades. Any materials and equipment shipped by rail must be transferred for truck delivery from distant rail sidings. Workforce mobilization and housing costs are substantially increased. In addition, the remote location increases many of the other costs mentioned above.

The Control Cost Manual does not address these costs in any way, yet these are real costs that would be incurred if NGS were required to install an SCR system for BART.

In summary, the Control Cost Manual is flawed in many ways and is not sufficient, in and of itself, for estimating the costs of a retrofit SCR project at NGS.

(iii) Summary and conclusions.

It is inappropriate for EPA to use the NPS cost estimates to make any determination regarding BART for NGS. EPA could not impose AQC equipment requirements on a facility through the BART process without acknowledging the true cost of the equipment to the facility and its customers. Estimating costs accurately is crucial to providing a true evaluation of the financial impact of adding NO_x controls at NGS and making sound choices between competing control technologies. Unless the assessment of the cost impact is based on accurate estimates, imposing any requirement through the use of the BART process to install additional control equipment, much less the most expensive control equipment, would be unlawful.

(2) The use of half of a reactor on Unit 2 at NGS.

In what appears to be an EPA effort to posit some "middle ground" between requiring either combustion controls only or SCRs on all three units at NGS, EPA suggests that half of an SCR reactor might be installed on Unit 2. NGS is the primary source of electricity for CAP. Through the United States Bureau of Reclamation, CAP holds a 24.3 percent entitlement to the net output of NGS, both for CAP use and for revenue generation through sale of power surplus to pumping requirements. As a consequence, the reliability of all NGS units is of utmost importance. CAWCD believes strongly that the installation of half an SCR reactor on Unit 2 of NGS would adversely affect the reliability of the unit and the ability of the operator to maintain stable operation. At the same time, it would produce no cost savings.

- SCR systems add approximately 10 to 13 in water gauge (wg) of flue gas draft pressure. Boiler furnace control is maintained by having the induced draft (ID) fans maintain the correct pressure in the boiler to allow proper fire ball creation as well as maintaining safe levels of pressure suction on the boiler. This boiler is not sectionalized. Upon leaving the boiler, the flue gas separates into two flue gas streams or "trains." This increases the challenge of maintaining furnace boiler pressure. Failure to maintain furnace boiler pressure is the most frequent cause of boiler trip and upset. This is a significant concern for CAP from a reliability standpoint. In addition, frequent boiler upset could lead to unsafe working conditions at the plant.

- To make a "half" SCR system work properly once installed on Unit 2, further stiffening of the boiler and enhanced digital control systems (DCS) would be needed. These added costs are not included in EPA's BART analysis. While the ANPR assumes that there would be significant savings from the use of a half SCR system, the additional construction and operating costs entailed by the Plant safeguards necessary to mitigate the potential operational hazards would erode any savings that might otherwise occur.

In summary, the addition of a half reactor on Unit 2 at NGS would introduce serious reliability and safety concerns without substantially lowering control costs.

(3) The impact on the Plant's net output.

It should be noted that, if SCRs were determined to be BART for NGS, additional auxiliary power would be required to run the new NO_x control systems. The power requirements of each system vary, depending on the type of technology and the complexity of the system. As noted above, SCR systems add approximately 10 to 13 in wg of flue gas draft pressure. The energy impact of each SCR installed is considered an energy penalty resulting from the operation of the control technology itself along with its associated systems (i.e., ammonia distribution). These direct energy impacts include the auxiliary power consumption of the control technology and the additional draft system power consumption to overcome the additional system resistance (pressure loss) of the control technology in the flue gas flow path. The cost of these energy impacts includes additional fuel costs and/or the cost of generation lost as a result of operating the control technology. This additional energy penalty would affect CAP's entitlement to 24.3 percent of NGS's net output,[63] and would thus reduce revenues from sales of power surplus to CAP's pumping needs. The loss of such revenues would have a direct impact on CAWCD, as these revenues offset, dollar-for-dollar, the amount that CAWCD must repay each year for the construction costs of the CAP. The lost revenues would also reduce the amounts flowing to the Lower Colorado River Basin Development Fund from this source, revenues which, by law, are now also used to help pay the costs of Indian water rights settlements in Arizona.

(4) Use of ammonia reagent.

An SCR system utilizes ammonia-based reagent to promote the reduction of NO_x to nitrogen and water. The reagents that are typically used are anhydrous ammonia, aqueous ammonia or urea. SRP's BART study assumed that anhydrous ammonia would be used. SRP's study concluded that 31 tons of anhydrous ammonia (about two tanker trucks) a day would be needed to service SCR control equipment. Anhydrous ammonia is a nearly pure formulation of ammonia that contains between 99.5 percent and 99.8 percent ammonia on a weight basis. Aqueous ammonia is a mixture of ammonia and water that typically contains between 19 percent and 30 percent ammonia on a weight basis. Urea is a nitrogen-rich chemical compound that releases an ammonia-laden vapor when combined with water and heated under pressure. Approximately 0.57 pounds of ammonia can be generated from each pound of urea used. For NGS, use of any of the three types of reagents would require shipping by truck since there is no rail delivery option. This is especially dangerous when using anhydrous ammonia, as a leak or accident causing rupture of the transportation tank could result in fatalities. Anhydrous ammonia is highly toxic and fatal on human contact. Aqueous ammonia and urea, while not fatal upon human contact, entail more capital and operation and maintenance (O&M) costs that would have to be added to SRP's existing cost estimate. Additionally, the use of anhydrous ammonia or aqueous ammonia above 19 percent concentration requires compliance with EPA's Risk Management Program, as well as OSHA's Process Safety Management program.

(5) EPA's modification of key assumptions.

[63] The resulting reduction in the Plant's heat rate would also exacerbate the impact of potential carbon regulation requirements.

EPA modified several key assumptions used by SRP in estimating the effectiveness of SCRs versus combustion controls, often departing from accepted practice and protocols and even its own prior conclusions and statements in this rulemaking. As a consequence, EPA consistently overstated the improvement in NO_x emission rates and in visibility that would result from the use of SCRs as opposed to combustion controls at NGS.

(a) H_2SO_4 removal.

H_2SO_4 emissions are an important input to the CALPUFF model used to predict visibility impairment. Higher sulfate emissions generally result in higher predicted visibility impairment. EPA's estimate of the amount of H_2SO_4 removed in the boiler system is much larger than that assumed by SRP. EPA assumed 51 percent removal (a 0.49 penetration factor, meaning 49 percent of the sulfuric acid penetrates through the equipment, while 51 percent is captured by the equipment). SRP assumed ten percent removal (a 0.90 penetration factor). The assumption of greater H_2SO_4 removal efficiency in the air heater reduces H_2SO_4 emissions under all of the scenarios, but the magnitude of H_2SO_4 emissions from SCR control systems is significantly greater than for combustion controls. As a consequence, this change in assumptions by EPA exaggerates the incremental visibility improvement predicted from the SCR control option as opposed to that predicted for combustion controls. It is also contrary to sound operating practices.

Removal of SO_3 in the air heater is dependent on operating the air heater at a cold-end metal temperature that is below the acid dewpoint temperature. Condensation of H_2SO_4 aerosols will occur at this low temperature. A much more significant O&M problem is presented if 51 percent of the acid gas is removed by the air heater than if ten percent is removed. Indeed, the operation of the air heater below the acid dewpoint temperature should be avoided so as to prevent corrosion from the acid condensation on the air heater surfaces and also to prevent the formation of ammonium sulfates and ammonium bisulfates (with ammonia slip from SCR), which would plug the air heater. A 51 percent removal of SO_3 in the air heater, as assumed by EPA, is neither a desirable nor plausible method of operation at NGS.

Furthermore, the EPA docket for this rulemaking indicates that SRP provided EPA with a written BART modeling protocol in September 2007 wherein SRP, in a footnote to Table 1-1, not only indicated its use of the EPRI method to derive H_2SO_4 emissions, but also provided the assumed control values for various pieces of equipment for EPA's review. In a letter from EPA to SRP dated July 1, 2008, EPA approved SRP's modeling protocol conditional on several changes given in the letter, which were subsequently made by SRP. EPA made no request in that letter that SRP modify the H_2SO_4 method used or the assumed control values. EPA's belated change to these key assumptions cannot be squared with the administrative record or with a sound technical and engineering approach.

(b) SO_2 to SO_3 conversion rate in the SCR.

EPA assumed an SO_2 to SO_3 conversion rate across the SCR of 0.5 percent, achieved by the use of an ultra-low conversion SCR catalyst. SRP assumed an SO_2 to SO_3 conversion rate of 1 percent. In assuming the use of an ultra-low conversion catalyst, EPA relied solely on a recent requirement for such a catalyst in a PSD permit issued by the Arizona Department of Environmental Quality (ADEQ) for a different plant and ignored accepted design parameters. The consequences of this change in assumptions are to overstate the effectiveness of SCR technology and to ignore the increases in costs that the use of an ultra-low conversion catalyst would entail.

The effect of EPA's having assumed the use of an ultra-low conversion catalyst is to lower modeled H_2SO_4 emission rates for SCR controls, thereby forcing the model to show a greater improvement in visibility over the baseline scenario than one would see with NO_x reductions alone resulting from the use of SCR technology. Specifically, the SO_2 to SO_3 conversion rate affects the predicted H_2SO_4 emissions from the SCR control option, because SO_3 is assumed to be converted directly into H_2SO_4. Assuming a lower SO_2 to SO_3 conversion rate exaggerates the incremental visibility improvement that is predicted by the model for an SCR system utilizing a 0.5 percent conversion catalyst. This effectively makes SCRs appear to be more cost-effective on a dollars per deciview ($/dv) basis than they would be shown to be if a standard 1 percent SO_2 to SO_3 conversion rate were used as proposed by SRP.

The use of a 1 percent SO_2 to SO_3 oxidation rate is a standard design parameter for SCR systems. Documents such as the ICAC Whitepaper on Selective Catalytic Reduction Control of NO_x Emissions From Fossil Fuel-Fired Electric Power Plants suggest that SCR catalyst can be designed for a 0.5 percent SO_2 to SO_3 oxidation rate. However, as indicated in the ICAC Whitepaper, the lower rate is typically used for high sulfur coal applications. The Whitepaper states, "SCR catalyst ranged from 0.5 percent to 2 percent for the initial charge of catalyst for most bituminous coals and up to 3 percent for sub-bituminous coals." Industry experts indicate that a 1 percent to 3 percent oxidation rate is typically applied in PRB, or low sulfur fuel, applications to reduce catalyst costs. The fuel at NGS is low sulfur, western bituminous fuel, which is similar in sulfur content to a PRB fuel. Thus, the ICAC discussion is applicable, and SRP's use of a 1 percent conversion rate was sound (and, indeed conservative, as it is at the low end of the applicable range of conversion rates).

SCR installations applied to PRB plants are among the most difficult from a catalyst life standpoint. Formulation of the catalyst is very site specific for PRB applications to minimize the poisoning and plugging effects of PRB fuels. A high level analysis such as BART should employ the standard design point for air quality processes, unless the applicability of an alternative is fully documented. The standard design point for SO_2 to SO_3 oxidation on an SCR catalyst is 1 percent. The ANPR references no documentation to support the feasibility of a 0.5 percent conversion rate for an SCR at NGS.

In addition, even if feasible, the use of a catalyst capable of achieving a 0.5 percent SO_2 to SO_3 conversion rate would increase costs significantly. As the ANPR indicated, SO_2 to SO_3 oxidation is a function of the catalyst activity, or the ability to convert NO_x to N_2 and water. Reducing the oxidation of SO_2 to SO_3 also reduces the catalyst activity to convert NO_x to N_2 and water. As a result, more catalyst and a larger catalyst reactor area would be needed, and EPA would have to increase the estimated overall capital cost and the annual operation, maintenance and replacement expense of the SCR system in its BART assessment for NGS.

(c) Hydrogen fluoride (HF) and hydrogen chloride (HCl).

These components should not be included as particulate emissions components, or included in any other manner, in the modeling analysis. The belated inclusion of these pollutants in EPA's modeling analysis represents a significant departure from accepted modeling protocols and from EPA's own record in this rulemaking.

Inclusion of HF and HCl as visibility impairing pollutants has not been typical of CALPUFF modeling applications for either BART or PSD purposes. EPA's Regional Haze Regulations and Guidelines for BART Determinations (July 6, 2005), the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts (EPA-454/R-98-019, 1998), and two subsequent updates to the IWAQM Phase 2 report (a Reassessment update and a Clarification update) issued in draft as recently as August 2009 make no mention of HCl or HF as visibility impairing pollutants, much less how they might be incorporated into the CALPUFF modeling analysis. The Western Regional Air Partnership (WRAP) Regional Planning Organization (RPO) modeling protocol also makes no mention of these pollutants nor did the EPA indicate the need for their inclusion when approving SRP's air dispersion modeling protocol in a letter to SRP dated July 1, 2008. It is clear that these pollutants are not being assessed as visibility impairing pollutants in other BART determinations being performed by States, RPOs, or the owners of other facilities around the country. Introducing new pollutants into visibility analyses without the appropriate documentation, justification of their importance, the methodology to be used in analyzing their impacts, or peer review is neither sound science nor proper regulatory action.

(d) NO_x emission rate.

In the ANPR, EPA proposes to use, and states that it performed its assessments based on, a lower NO_x emission rate of 0.06 lb/MMBtu associated with the SCR control option than the emission rate assumed by SRP. As a result, EPA overstated both the reduction in NO_x emissions and the visibility improvement achievable with SCR as compared to that achievable with combustion controls alone. The evaluation of SCR by SRP is based upon an 82 percent to 84 percent NO_x removal efficiency, at a NO_x emission rate of 0.08 lb/MBtu. This removal efficiency is consistent with the removal efficiency used by EPA in the ANPR for Four Corners Power Plant. From a process standpoint, there is no difference between Four Corners and NGS in terms of the NO_x removal efficiency that can be achieved with SCRs. Therefore, the evaluation of cost effectiveness of SCR technology should be based upon an outlet emission rate of 0.08 lb/MBtu, as recommended by SRP and its consultants. It is clear that, had EPA used an SCR-controlled emission rate for NO_x of 0.08 lb/MBtu (as recommended by SRP) in its visibility modeling analysis, it would not have seen greater visibility improvements than SRP did when modeling the effects of SCR control technology.

(e) Background ammonia (NH_3).

The background ammonia concentration is a critical input to the CALPUFF model, because the amount of available ammonia determines the extent to which particles of ammonium nitrate and ammonium sulfate will form and impair visibility. The use of a higher background ammonia concentration results in predictions by CALPUFF of a greater degree of visibility impairment, and serves to increase the calculated benefit of the more stringent control options.

Ambient NH_3 is an important input to the model because of the compound's ability to convert SO_2 and NO_2 to ammonium sulfates and ammonium nitrates, respectively, which are key visibility reducing pollutants. The presence of NH_3 in the atmosphere preferentially converts SO_2 to ammonium sulfates over converting NO_2 to ammonium nitrates. So, the more limited ambient NH_3 concentrations are, the more likely that ammonium nitrate formation will be limited as well, since much of the NH_3 would have been tied up in the conversion of SO_2 to ammonium sulfates. This conversion is also highly dependant upon atmospheric moisture and temperature. Therefore, the issue at hand is determining the appropriate ambient NH_3 concentrations during various times of the year (e.g., on a monthly basis), which in turn will determine the amount of visibility-degrading ammonium nitrates that are created.

According to a paper authored by Sandro Fuzzi,[64] almost all sources of NH_3 are biological in origin, and agricultural activities are by far the most important contributors to the atmospheric budget of NH_3. Given the area's demonstrable lack of agricultural activities, one would expect that the area does not exhibit high concentrations of biological ammonia, and that the area is thus limited in its ability to convert NO_2 to visibility-degrading ammonium nitrates. Even EPA, in its IWAQM Phase 2 document, indicates that arid lands (such as the desert southwest) have some of the lowest ambient concentrations of ammonia in the country. As further indicated by EPA's IWAQM Phase 2 document, another factor that may cause an area to have lower ambient NH_3 concentrations are high ambient levels of sulfates. In the presence of sulfates, any NH_3 available in the area will first convert the sulfates to ammonium sulfates, leaving less free NH_3 available to convert NO_x to ammonium nitrates. The fact that there are several major sources of sulfates located in the Four Corners area is another reason one would expect to see low ambient concentrations of NH_3 in the vicinity of NGS.

SRP provided EPA with a written BART modeling protocol in September 2007. That protocol specifically identified the background NH_3 values that would be used in the modeling analysis, and further indicated that such values had previously been accepted by the NPS for the Class I area visibility analysis that supported a PSD application for the Desert Rock facility. In a letter from the EPA to SRP dated April 29, 2008, EPA confirmed the background NH_3 values proposed by SRP (and already in use by SRP in its BART study) and acknowledged that Federal Land Managers had approved these values for purposes of modeling the projected impacts of the Desert Rock facility on nearby Class I areas. The EPA simply requested that SRP perform a sensitivity analysis that compared the proposed SRP background NH_3 values with the IWAQM Phase 2 default constant background ammonia value of 1 part per billion (ppb).[65] In a second letter from the EPA to SRP dated July 1, 2008, EPA formally approved SRP's modeling protocol

[64] Fuzzi, Sandro. "Overview of the Biogenic Sources of Atmospheric Trace Compounds Due to Agricultural Activities," Aerobiologia: International Journal of Aerobiology (1996).

[65] Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts, December 1998, EPA-454/R-98-019, at 14. This document notes an ammonia value of 1 ppb for arid lands at 20 degrees centigrade,

with several conditional changes. None of the conditional changes requested that SRP modify the background NH_3 values. In fact, the EPA withdrew its request that SRP do a sensitivity analysis using a default constant of 1 ppb NH_3 background ammonia concentration, saying that it "believe[s] the background [NH_3] values already used are appropriate."

It was not until a meeting with SRP on May 7, 2009, over 19 months after SRP's submittal of the modeling protocol and over 11 months after the EPA's approval of that protocol, that EPA informed SRP that it had decided to increase the background NH_3 concentrations that would be assumed for purposes of the BART modeling analysis. Indeed, for some months under its modeling analysis, EPA increased the assumed background NH_3 values to levels that exceed even the IWAQM Phase 2 default value of 1 ppb for arid lands.

In a letter from SRP to EPA dated June 3, 2009, SRP recognized the importance that background NH_3 concentrations have in the modeling results and the effect that increased background NH_3 concentrations could have on the outcome of the BART determination. SRP's letter cited a number of compelling reasons why EPA's novel "back-calculation" method for deriving background NH_3 values is erroneous. CAWCD agrees with SRP.

Background ammonia values are a critical input to the CALPUFF model. It is essential to use an accurate value for background NH_3, because that value has a significant influence on the modeled estimates of the amounts of ammonium nitrate and ammonium sulfate that are formed in the model's chemical transformation mechanisms. Even EPA acknowledges in its IWAQM Phase II document that "accurate specification of this parameter is *critical* to the accurate estimation of particulate nitrate concentrations."[66]

All parties have acknowledged that there is a lack of monitored background ammonia data for the Colorado Plateau. EPA cited the lack of such data in the ANPR as a reason for using its flawed back-calculation method. SRP proposed to initiate a monitoring program to *measure* background ammonia values at several sites on the Colorado Plateau. A conceptual monitoring plan was submitted to EPA by SRP in June of 2009. On multiple occasions, CAWCD understands, through both verbal and written communications, SRP subsequently attempted to contact EPA to request the opportunity to discuss the proposed ammonia-monitoring program. SRP also purchased ammonia monitoring equipment so that the long lead time associated with obtaining the equipment would not prevent the initiation of a winter 2009/2010 monitoring program. We are told that EPA recently declined SRP's offer to perform ammonia monitoring, saying, inexplicably, that such a program would not yield data that would be useful in the BART determination. Apparently, the Agency chooses not to be confused by the facts.

EPA should either honor its previous written approval of SRP's background ammonia values and use those agreed-on values in its BART assessment or accept SRP's offer to perform an ambient air monitoring study to measure the actual ambient ammonia concentrations in the area. If EPA elects to permit the collection of additional data regarding actual background ammonia concentrations, it should defer further modeling and any BART determination for NGS until after the data are collected and analyzed.

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[66] Id. (emphasis added).

(6) EPA's use of alternate visibility metrics.

Visibility metrics are necessary to assist the regulatory authorities in making rational BART determinations based on the outcomes of both the cost and visibility impact analyses. A common visibility metric in use today in BART applications is the $/dv metric suggested in the BART Guidelines. The $/dv metric allows a comparison of the costs (including incremental costs) of implementing a particular control strategy to the visibility improvement to be realized from the implementation of that control strategy.

In the ANPR, EPA requests comment on the alternate visibility metrics discussed in the ANPR, including proposed metrics that purport to take into account a facility's visibility impacts on multiple Class I areas. The alternate metrics do one of two things, neither of which has any support in the available literature or any precedent in Agency practice: (1) they add the predicted visibility improvement across all days for all Class I areas, or (2) they multiply the predicted visibility improvement expected in each Class I area by the land area of the Class I area in km^2, then add the products obtained. In this way, very small visibility improvement numbers are made to look much bigger and more significant than they are, which seems to be the principal purpose of the ANPR's exercise on this issue. These suggested changes in methodology can only be explained as an attempt artificially to inflate the values used for visibility improvement and thereby reduce the ostensible cost-benefit ratio of the most expensive control option, as expressed in dollars per deciview ($/dv).

(a) Proposed summation metric.

It is inappropriate to add improvements over all Class I areas. A 0.5 dv improvement at one Class I area and a 0.5 dv improvement at another Class I area does not result in a 1 dv improvement. The improvement is a 0.5 dv improvement, which simply occurs at two different locations. Further, any one observer at any one Class I area would only experience a single 0.5 dv improvement (if, that is, a 0.5 dv improvement were humanly perceptible, which it is not). An individual observer does not perceive an additive improvement at multiple Class I areas; he or she can only experience the visibility improvement that has taken place at the Class I area that he or she is visiting. Adding improvements across multiple Class I areas effectively multiplies the threshold metric by the number of Class I areas, which flies in the face of the basic science of visibility perception.

This metric is akin to examining the effects on visibility at several locations within the *same* Class I area and adding them. Thus, if one receptor (or location) in a Class I area experiences a 0.5 dv improvement and another receptor (or location) at that same Class I area experiences a 0.5 dv improvement, one would conclude (wrongly) that the Class I area experienced a 1 dv improvement. A correct modeling result for a given Class I area is determined by finding the maximum (or the average) impact or improvement over all receptors, not by adding individual receptors at the Class I area.

(b) Proposed km^2 metric.

CAWCD disagrees that the size of a Class I area should be taken into account in assessing the cost-benefit of alternative control technologies. The goal of the Regional Haze Rule is to protect visibility at all Class I areas equally, and not to assign a higher value to those Class I areas that happen to cover "greater-than-average" acreage. The use of this alternate metric implies that larger Class I areas have greater significance than smaller areas. It also implies that visibility improvements are by definition greatest for the largest Class I areas, a result which is, of course, absurd. EPA does not provide any basis for the use of the dv-km^2 or enough information on how that metric was derived, and fails to explain its ostensible benefit as compared to more commonly discussed and accepted metrics, such as the $/dv metric, the use of which is clearly contemplated by the BART Guidelines.[67]

In summary, in the context of this proceeding, the most appropriate metric for evaluating the cost-benefit of the available control options is $/dv, calculated for each individual Class I area or, as an alternative, calculated as an average over all Class I areas evaluated as part of the BART analysis.

(7) ENVIRON International Corporation's air quality modeling study for Four Corners region (ENVIRON Study)[68] supports the conclusion that SCR would produce no meaningful improvement in visibility over that achievable with LNB/SOFA alone.

The Four Corners Air Quality Task Force (FCAQTF) undertook this study to determine the potential air quality and visibility impacts of possible alternative mitigation strategies for the Four Corners area. The study used the Comprehensive Air Quality Model with Extensions (CAMx), which is a three-dimensional, multi-scale photochemical/aerosol grid model developed and maintained by ENVIRON.

In general, the study compared a 2005 emission source inventory to a potential future emission inventory to determine a base case scenario and then examine the impacts of five alternative mitigation scenarios. Scenario 1 of this study is relevant here, as it focuses on application of SCRs to control NO_x emissions (and other control technologies for SO_2) for the Four Corners Power Plant (FCPP) and the San Juan Generating Station (SJGS). The NO_x emission levels modeled at the two plants, using SCR technology, were 0.10 lb/MBtu and 0.07 lb/MBtu, respectively. For reference, SO_2 reductions were based on the presumptive BART limit of 0.15 lb/MBtu for FCPP and "consent decree limits" [69] for SJGS. Together, these resulted in overall emission reductions for the two plants of 16 percent in SO_2 emissions and 70 percent in NO_x emissions.

The report concludes that installation of SCRs at FCPP and SGJS will not appreciably improve visibility. Specifically, the report states:

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[67] 70 Fed. Reg. at 39130 col. 1, 39170 col. 3. Apart from the fundamental deficiencies in the proposed metrics themselves, there appear to be numerous math errors in the tables accompanying the discussion of metrics. In Table 36, for example, every listed sum in the table is different from the actual sum of the numbers listed in a given column (e.g., in Column A, the sum shown is 24,943, while the sum of the numbers listed in Column A is actually 35,783). None of the other sums stated is equal to the actual sum of the numbers listed in the respective columns. If EPA has made such obvious math or data errors here, it leads one to wonder whether other EPA findings or conclusions may be incorrect as a result of mathematical or other errors.

[68] http://www.nmenv.state.nm.us/aqb/4C/Documents/FinalRepRev20090806.pdf

[69] ENVIRON study, Appendix C, indicates the Consent Decree enforceable condition of 90 percent SO_2 reduction and the presumptive BART limit for NO_x of 0.23 lb/MBtu were used for the units at SJGS.

> *EGU emissions reductions result in some days with visibility improvements of 0.5 to 1 dv but more than 98% of days during the year have predicted improvements of less than 0.5 dv.*[70]

These "visibility improvements" are, therefore, below the level of human perceptibility. Although NGS was not included in the ENVIRON Study, it is reasonable to assume that the results of the study would apply similarly to NGS. The visibility changes resulting from the use of SCR technology, as predicted by the ENVIRON Study, are strikingly similar to the results predicted by the SRP BART analysis, and both diverge similarly, and significantly, from the results predicted by EPA in the ANPR. At a minimum, the significant discrepancies between the results of EPA's analysis and the results of the ENVIRON and SRP studies suggest that further EPA analysis is necessary to better understand and quantify the visibility changes, if any, that could reasonably be expected from the installation of SCR technology at NGS. The types of analyses conducted by ENVIRON would provide an inexpensive alternative for evaluating how visibility would be affected by the installation of SCRs at NGS.

(8) Visibility improvement and the cost effectiveness of the control options.

BART may not be imposed on a facility without an assessment of the degree of visibility improvement to be expected from the expenditures that would be necessitated by the various control options. In reviewing EPA's original BART rules for regional haze, the U.S. Court of Appeals for the D.C. Circuit held unlawful the provision in those rules that directed states to consider the BART visibility improvement factor by aggregating the visibility improvement effects that would be expected in a Class I area as a result of imposing BART on all sources subject to BART.[71] The court specifically rejected "EPA's take on the statute" at that time, under which "it is . . . entirely possible that a source may be forced to spend millions of dollars for new technology that will have no appreciable effect on the haze in any Class I area."[72] With reference to the intersection between the BART cost factor and the BART visibility improvement factor, *American Corn Growers* addressed the question of how the state BART-determining agency is "to determine what is too costly (and what is not) for a particular source."[73] The court held that "the statute answers that the state must consider the degree of improvement in visibility in national parks and wilderness areas that would result from the source's installing and operating the retrofit technology."[74]

Thus, under *American Corn Growers*, BART may not be imposed on a facility without an assessment of the degree of visibility improvement at a Class I area that would result from the expenditures entailed by installation and operation of BART at that facility. Moreover, any substantial expenditure for BART – certainly any expenditure amounting

[70] ENVIRON Study, Executive Summary at 5 (emphasis added).

[71] Am. Corn Growers Ass'n v. EPA, 291 F.3d 1, 6-7 (D.C. Cir. 2002).

[72] Id. at 7.

[73] Id.

[74] Id.

to "millions of dollars"[75]– is clearly unjustifiable if it would not produce an "appreciable effect" in improving visibility in a Class I area through a reduction in regional haze.

Although the court did not define what specific degree of visibility improvement would be "appreciable," EPA suggested, in promulgating the current BART rules, that it is appropriate for BART determinations to use visibility impact thresholds such as those used for "subject to BART" determinations.[76] "[C]onsideration of the cost-effectiveness of visibility improvements (i.e., the cost per change in deciview)"[77] follows logically from *American Corn Growers*' focus on the trade-off between control costs and visibility improvement.[78] Substantially higher control costs, such as those associated here with SCR, could not be justified in the absence of a particularly high degree of incremental visibility improvement. That point is particularly significant in this proceeding because SRP's studies demonstrate that SCRs *would produce almost no incremental improvement in visibility, but would entail enormous additional costs*.

The NGS participants are voluntarily installing combustion controls – the presumptively applicable BART technology – at a cost of approximately $43 million, to reduce NO_x emissions. Combustion controls will reduce NO_x emissions significantly and produce a calculable (albeit humanly imperceptible) improvement in visibility at a fraction of the cost of SCRs. Indeed, the bulk of the calculable visibility benefit will be achieved by the installation and operation of combustion controls alone. In contrast, SCRs would cost over 15 times more than combustion controls – $660 million in capital costs plus $13 million in additional annual operation and maintenance costs – without producing any significant incremental visibility benefit. If downstream particulate controls are required in addition to SCRs, total capital costs could reach $1 billion. The costs of BART controls versus the visibility benefits that would be realized from those controls are illustrated below in Figure 1.

SRP's studies, which were performed in accordance with EPA's protocols and approved modeling assumptions, show that the installation and operation of LNB/SOFA will produce, on average, about a half a deciview (0.47 dv) improvement in visibility in nearby Class I areas. Installation of SCRs, in addition to combustion controls, would produce an incremental improvement in visibility, on average, of less than one quarter of a deciview (0.23 dv) – a plainly imperceptible additional improvement – at a cost of another $660 million to $1 billion in capital expenses alone. EPA has said that "a one deciview change in haziness is a small but noticeable change in haziness under most circumstances when viewing scenes in a Class I area."[79] It is doubtful that either LNB/SOFA or SCR would produce sufficient improvement in visibility to be perceived by the normal observer. But clearly, an investment of as much as $1 billion to achieve

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[75] Id.

[76] See 70 Fed. Reg. at 39129 col. 3-39130 col. 1; id. at 39130 col. 1 (noting that, "[f]or example, a 0.3, 0.5, or even 1.0 deciview improvement may merit stronger weighting in one case versus another").

[77] Id. at 39130 col. 1.

[78] See 291 F.3d at 7.

[79] 74 Fed. Reg. at 44327 cols. 2-3; EPA, Regional Haze Regulations,.64 Fed. Reg. 35714, 35725 cols. 2-3 (July 1, 1999).

less than a quarter of a deciview improvement – an indisputably imperceptible change – cannot be justified under any rational cost-benefit analysis.

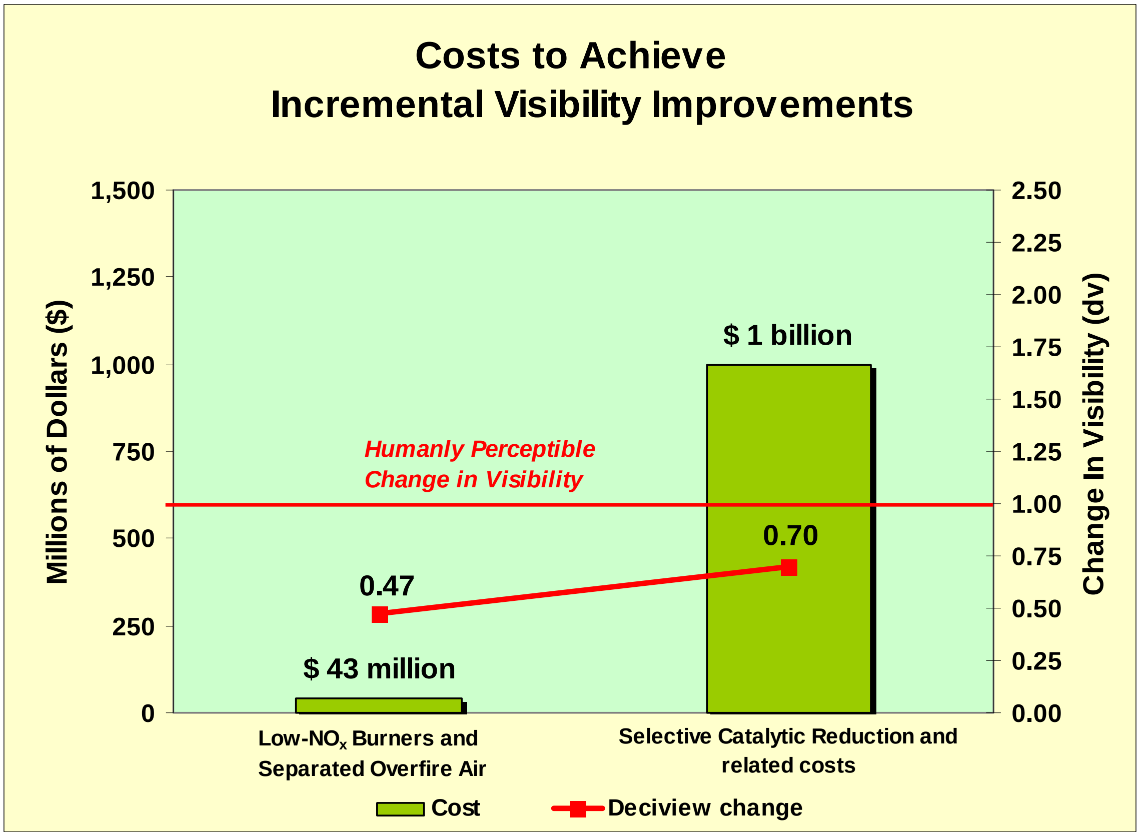

Figure 1 – Costs to Achieve Incremental Visibility Improvements

It is apparent that the incremental visibility benefit that could be achieved using SCRs is insufficient to justify that technology's enormous additional cost. Under no circumstances could it be concluded that SCRs constitute BART for NGS.

(9) The Plant's remaining useful life.

EPA states that SRP used an amortization period of 20 years for the costs of NO_x controls at NGS, "anticipating that the remaining useful life of Units 1 – 3 is at least 20 years." EPA requested comment on "the use of this period of time for the remaining useful life of NGS." In its letter of June 3, 2009, to Dr. Anita Lee of EPA, SRP stated that:

> As demonstrated in the December 2008 BART analysis submitted by SRP, SCR is not cost-effective even with an assumed 20-year amortization period. As SRP mentioend in the May 7 meeting, as well as in previous communications with EPA, the long-term operational future of NGS is dependent on renewing various leases and right-of-way agreements with the Navajo Nation among other factors. While the NGS owners are planning to secure renewal or extension of these agreements, that outcome is not a certainty. In light of that uncertainty, any cost-effectiveness

> analyses should include an evaluation based on a shorter amoritzation period. Because SCR is not cost-effective with a 20-year amortization period, it would be even more clearly cost-ineffective if one assumes a remaining useful life for NGS of 9 to 10 years (the period from now until expiration of the current lease term).

Indeed, for the reasons discussed in detail above, an even more relevant period would be 4 years (i.e., the period beginning with assumed control installation in 2015 and ending in 2019, the current term of the plant-site grants and other agreements).

The remaining useful life of NGS is a matter of considerable importance to CAWCD, particularly inasmuch as NGS is virtually our sole source of power and contributes so significantly to our finances. CAWCD does not have the luxury of having a diversified, base-load power portfolio. We have essentially one power resource – NGS. The choice of NGS as the power supply for CAP was made by the Administration and Congress at the time the CAP was authorized in order to avoid the construction of new hydroelctric dams in the Grand Canyon. Thus, the United States' acqusition of the largest single share of NGS was an environmental compromise that was actually suggested by environmental leaders, like David Brower of the Sierra Club, at the time the CAP authorizing legislation was being debated in Congress, and was subsequently negotiated by then Secretary of the Interior Stewart Udall.[80] For purposes of its long-term financial plan, CAWCD has assumed that NGS would operate at least through the end of the CAP repayment period (2045). However, that assumption has now been undermined significantly.

NGS is well operated and well maintained. However, as discussed in detail in these comments, the Plant currently faces a number of significant challenges, including the need to renew or extend agreements for the plant-site by 2019, the need to renegotiate certain terms and conditions of the coal supply contract for NGS and to further extend the term of that contract, and the prospect of greenhouse gas and other air quality regulations that could result in significant, new but as yet unknown costs. As a consequence, the Plant participants face the prospect of having to amortize an investment of as much as $1 billion in as little as four years.

In this context, the choice of BART for NGS could dramatically shorten the Plant's useful life. CAWCD's greatest fear is that, under current conditons, the establishment of a NO_x emission limit that requires the installation of SCRs could cause the participants to decide that the Plant is no longer viable economically. That would have disastrous consequences for the CAP and its water users. BART is to be an emission limitation that an existing source can meet cost-effectively – not a financially onerous requirement that has the effect, deliberate or not, of shutting down or otherwise shortening the life of that source; any such requirement is, by definition, not cost-effective and thus cannot be BART.

IV. Summary and Conclusions

EPA should determine that a NO_x emission limit of 0.24 lb/MBtu, achieved using low NO_x burners and separated overfire air on Units 1-3 of NGS, is BART for NGS. EPA

[80] This history is recounted in Rich Johnson, The Central Arizona Project, 1918-1968, at pp. 167-72, 197, and 199-201 (University of Arizona Press, 1977).

will have the ability in the future to consider using the "reasonable progress" provisions of its Regional Haze Rules to require more of NGS in subsequent planning periods, if necessary to meet the rules' requirements and objectives.

CAWCD believes that there are several good reasons to require the installation and operation of low NO_x combustion controls as BART for NGS and to wait to determine whether there is a need for additional, more costly control devices in a subsequent period to meet reasonable progress requirements:

- Models often change and advance in scientific accuracy over time. One example of this is ENVIRON's use of the CAMx air dispersion model to predict visibility impacts of emissions reductions in the Four Corners area.
- Data on actual background ammonia concentrations (a *critical* model input) could be made available should EPA accept SRP's offer to undertake an ambient monitoring study.
- SRP will better understand whether the LNB/SOFA system can reduce NO_x emission rates at the NGS units even further below the proposed BART level of 0.24 lb/MBtu. With experience and with optimization of the LNB/SOFA system, SRP may be able to reduce NO_x emissions rates to levels in the range of 0.20 lb/MBtu, thus reducing overall NO_x emissions by an estimated 4,000 tons per year below the 0.24 lb/MBtu emission level. As noted previously, following the installation of LNB/SOFA on Unit 3 of NGS, the Unit 3 NO_x emission rate was found to be less than 0.24 lb/MBtu rate. This measured emission rate is significantly less than the presumptive BART emission level of 0.28 lb/MBtu and was found to be less even than SRP's proposed NO_x emissions limit. Once the LNB/SOFA system has been installed and operated for a meaningful period of time on all three units, SRP and EPA will also be better able to predict the impact of LNB/SOFA in improving and protecting visibility at the nearby Class I areas and whether even greater emission reductions may be needed in the future.
- Proceeding in this fashion would allow the participants in NGS the additional time they need to deal with the other significant challenges facing the Plant, such as the need to renew the plant-site lease and the Section 323 Grants, the need to renegotiate the coal supply contract for NGS, and the need to understand and address any regulatory requirements to control greenhouse gas emissions and reduce emissions of other pollutants, such as mercury or other listed hazardous air pollutants that EPA may regulate.

It would make no sense for EPA to set a standard today that would risk the future of the Plant, particularly when another control option is available that does not entail that risk, yet achieves a visibility benefit at a reasonable cost. This is particularly true where, as here, EPA will have the opportunity to consider requiring more in the future if necessary to continue achieving reasonable progress in protecting visibility in Class I areas.