United States Department of the Interior

FISH AND WILDLIFE SERVICE
National Wildlife Refuge System
Branch of Air Quality
7333 W. Jefferson Ave., Suite 375
Lakewood, CO 80235-2017

IN REPLY REFER TO:

FWS/ANWS-AR-AQ

August 17, 2010

Ms. Mary Uhl
Air Quality Bureau
New Mexico Environment Department
1301 Siler Rd., Building B
Santa Fe, New Mexico 87507

Dear Ms. Uhl:

On June 22, 2010, we received New Mexico's draft regional haze implementation plan for review. We appreciate the opportunity to work closely with the State through the development and review of this plan. Cooperative efforts such as these ensure that, together, we will continue to make progress toward achieving natural visibility conditions at our National Parks and Wilderness Areas.

This letter acknowledges that the U.S. Department of the Interior, National Park Service and U.S. Fish and Wildlife Service have received and conducted a substantive review of the New Mexico draft Regional Haze Rule implementation plan in fulfillment of your requirements under the federal regulations 40 CFR 51.308(i) for a 60 day consultation period with the Federal Land Managers. Please note, however, that only the U.S. Environmental Protection Agency (EPA) can make a final determination regarding the document's completeness and, therefore, ability to receive federal approval from EPA.

As outlined in a letter to each State dated August 1, 2006, our review focused on eight basic content areas. The content areas reflect priorities for the Federal Land Management agencies, and we have enclosed comments associated with these priorities.

We look forward to your response, as per section 40 CFR 51.308(i)(3). For further information regarding our comments, please contact Pat Brewer, National Park Service, at (303) 969-2153, or Tim Allen, Fish and Wildlife Service, (303) 914-3802.

TAKE PRIDE IN AMERICA

Again, we appreciate the opportunity to work closely with the State and compliment you on your hard work and dedication to improving visibility in our Class I national parks and wilderness areas.

Sincerely,

John Bunyak
Acting Chief, Air Resources Division
National Park Service

Sincerely,

Sandra V. Silva
Chief, Branch of Air Quality
U.S. Fish & Wildlife Service

Enclosure

cc:

Tom Melanson, Refuge Manager
Bosque del Apache NWR
1001 State Highway 1
San Antonio, NM 87832

Joe Saenz, Refuge Manager
Bitter Lake NWR
4065 Bitter Lake Road
Roswell, NM 88201

Tom Harvey, Refuge Supervisor (NM/AZ)
FWS Region 2
P.O. Box 1306
Albuquerque, NM 87103

Chris Pease, Refuge Chief
FWS Region 2
P.O. Box 1306
Albuquerque, NM 87103

Brian McManus, Chief Branch of Fire Management
National Interagency Fire Center
3833 South Development Ave.
Boise, Idaho 83705

John Benjamin, Superintendent
Carlsbad Caverns National
3225 National Parks Highway
Carlsbad, NM 88220

Jason Lott, Superintendent
Bandalier National Park
15 Entrance Road
Los Alamos, NM 87544

Joe Kordzi
Air Planning Section
US EPA Region 6,6PD-L
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Comments of the National Park Service and US Fish and Wildlife Service Regarding the New Mexico Regional Haze State Implementation Plan August 17, 2010

On June 22, 2010, the State of New Mexico submitted a draft Regional Haze Rule State implementation plan (SIP), pursuant to the requirements codified in federal rule 40 CFR 51.308(i)(2), to the U.S. Department of the Interior, National Park Service (NPS) and U.S. Fish and Wildlife Service (FWS). The NPS Air Resources Division staff and FWS Branch of Air Quality staff have conducted a substantive review of the New Mexico draft plan, and provide the comments listed below.

We look forward to the New Mexico Environment Department's (NMED's) response as per section 40 CFR 51.308(i)(3), and would be willing to work with the NMED staff towards resolving the major issues discussed below. For further information, please contact Pat Brewer, National Park Service, at (303) 969-2153, or Tim Allen, Fish and Wildlife Service, (303) 914-3802.

General Comments

New Mexico states that the draft plan is intended to fulfill the requirements of 40 CFR 51.308, thus our review was based on the requirements of the '308' Haze Rule.

New Mexico did not adequately demonstrate that all measures to ensure progress in meeting the regional haze goals were fully evaluated. This is a critical demonstration as it is apparent from the draft plan that the State does not meet its Uniform Rate of Progress (URP) goals, that visibility impairment due to contributions of in-State nitrate and sulfate sources appear to be increasing over this planning period at several Class I areas, and that two New Mexico Class I areas, Carlsbad Caverns National Park and Gila Wilderness, are predicted to have visibility degradation.

We recommend that New Mexico clarify in the draft plan, its consultation with Bernalillo County and coordination with respect to the haze rule.

Specific Comments

Chapter 1. Introduction

Figure 1-3: *Map of New Mexico Class I Areas,* depicts New Mexico's Class I areas and those within 100km of New Mexico's borders. The Regional Haze Rule requires that each state address each Class I area affected by its sources. This requirement of the rule does not provide for a fixed distance or 'cut-off' beyond the state's borders for assessing apportionment of impacts. Many states have either selected a more conservative distance of 300km or developed a model-based apportionment calculation.

In its discussion of natural sources of visibility impairment, the State makes the following statement, '…while organic carbon (OC) and coarse particulate matter (CM or PM_{10}) are more representative of natural sources such as wildfire and dust, respectively.' While OC, CM, and PM_{10}, are products of wildfire and dust, anthropogenic sources can also contribute significantly to monitored values of these pollutants. The State should provide additional information that supports the assertion that naturally occurring phenomena are solely responsible for these pollutant contributions.

Chapter 2. New Mexico Regional Haze SIP Development Process

The State declares that pursuant to 40 CFR 51.308(h)(2), the proposed draft SIP is adequate to ensure reasonable progress in meeting goals of the Regional Haze Rule. New Mexico does not meet the basic

requirements of the rule by allowing reasonable progress goals at certain Class I areas that actually result in degradation of visibility rather than improvement. Therefore, we do not agree that the plan is adequate in this respect.

Chapter 6. New Mexico Class I Area Baseline, Natural Conditions, and Uniform Rate of Progress

New Mexico acknowledges that the State must ensure no degradation in visibility for least impaired days over the plan period (per 40 CFR 51.308(d)). However, Table 6-4 – *Summary of Best and Worst Visibility Days for New Mexico Class I Areas*, illustrates that Carlsbad Caverns National Park and the Gila Wilderness will not meet this requirement.

Chapter 7. Visibility Impairment at New Mexico Class I Areas

Figure 7-13 – *Monthly Average Species Variation for All Sampled Days during the Baseline Period*, identifies two significant spikes in air pollution at the Gila Wilderness IMPROVE monitor. The State suggests that these spikes represent natural fire events with a highlighted note that this information needs verification. We agree that this assumption should be verified and would like to add that it is also possible that anthropogenic sources are capable of creating pollution spikes such as the ones at Gila Wilderness.

Chapter 8. Sources of Visibility Impairment

The reader is directed to the Western Regional Air Partnership (WRAP) Technical Support System for information regarding the emission inventories used by the State in developing its SIP. The plan references inventories "Plan02d" and "Prp18b", however these inventories are not described in detail. New Mexico is responsible for summarizing emission inventories, as well as their development and verification. The State is also responsible to explain how this information was used to develop and support its SIP. The burden of interpreting the technical support products developed by the WRAP should not be placed on the reader.

Chapter 9. Visibility Modeling and Source Apportionment

New Mexico utilizes non-guideline modeling techniques developed by the WRAP. Similar to the emission inventories, descriptions of these models should be included in the SIP narrative. The models, performance test, and applicability to the SIP development must be summarized by the State.

Please also discuss the term "relative response factor (RRF)" in more detail. This discussion should include the fundamental principles of RRF's and how they are integrated into the SIP development.

Within sections 9.4.1 thru 9.4.5, the paragraphs that are labeled "Sulfur Oxides" contain typographical errors in the text that incorrectly reference nitrogen oxides.

Chapter 10. Best Available Retrofit Technology (BART) Evaluation

The State follows EPA BART guidance for exemption by using the 8th highest impairment value, compared to annual average natural conditions. However, the modeling in support of these evaluations, as developed by the WRAP, does not follow CALPUFF modeling requirements. Therefore, we have suggested that the WRAP build in conservativeness to the BART exemption modeling by utilizing the 1st highest impairment value or by comparing the 8th highest value to the 20% best estimate of natural condition. Please provide additional information, such as modeling protocols and results, for all sources identified for BART exemption that supports New Mexico's decision to apply the 8th high impairment value and annual average natural conditions.

The BART exemption modeling should have used the receptors in Carlsbad Caverns rather than the IMPROVE monitor at Guadalupe Mountains to determine whether the BART eligible sources contributed more than 0.5 dv impact at Carlsbad Caverns. There are seven BART eligible sources that are closer to Carlsbad Caverns than Guadalupe; for these sources the dv impact at Carlsbad Caverns may be greater than reported using the IMPROVE monitor at Guadalupe.

In addition to supplementing the SIP with BART modeling protocols and results, New Mexico should also provide additional general information with respect to the BART exemption process. This information should clarify why additional controls were unnecessary or unreasonable for major facilities in New Mexico. This is particularly important information due to the fact that the State does not meet the URP for any of its Class I areas and has two Class I areas that show degrading visibility. Even if the BART eligible sources are not determined to be subject to BART, because New Mexico is not meeting URP, these sources should be considered as part of the reasonable progress analysis.

Table 10-2 *Visibility Impact Analysis of PNM's San Juan Generating Station*, suggests that 3-year averages of visibility impairment were evaluated for each Class I area. Averaging deciviews is not an appropriate method for evaluating visibility impacts from a selected source.

PNM San Juan Generating Station is the only BART-eligible facility determined to be subject to BART. We are very pleased that NM determined that BART for NO_x is Selective Catalytic Reduction plus sorbent injection. Attached to this letter is a detailed technical analysis of the PM and NO_x BART determinations presented by NMED in this draft SIP. The attachment also references several spreadsheets, which are being provided directly to NMED and EPA staff electronically.

Section 10.4 discusses control options for PM and NO_x but is silent on SO_2. Please clarify what SO_2 controls have been or are planned to be installed for BART for San Juan (even if this was covered under the previous 309 SIP).

Please clarify the annual emissions assumptions used in the 2000-2004 baseline and 2018 PRP18b emissions inventories for San Juan, and explain how these assumptions compare to the final BART determination.

Chapter 11. Reasonable Progress Goal Demonstration

The reasonable progress demonstration offered by New Mexico does not fully explain the State's efforts with respect to achieving improved visibility. For example, the State identifies the reasonable progress goals as determined by modeling and by its four factor analysis. However, there are two Class I areas, Carlsbad Caverns National Park and Gila Wilderness, for which the basic non-degradation requirement is not achieved. The State offers no explanation or argument that all efforts have been made to adequately support its reasonable progress goals.

Three refineries were identified in the SIP for additional reasonable progress analyses. Please give additional explanation as to why these specific facilities were selected for additional analyses. Also, please provide more information that supports New Mexico's decision not to consider additional controls for major sources, despite not meeting its URP goals and having predicted degraded visibility. Also, we note that the reasonable progress analysis needs to address both SO_2 emission sources and NO_x emission sources because New Mexico is proposing the SIP under Section 308 of the Regional Haze Rule.

In section 11.3, New Mexico sets reasonable progress goals that achieve less visibility improvement than the URP. Per 40 CFR 308(d)(1)(ii), the plan must also provide "an assessment of the number of years it would take to attain natural conditions if visibility improvement continues at the rate of progress selected by the State as reasonable."

In section 11.3.3, page 140, the first sentence identifies the monitor for Carlsbad Caverns National Park as being part of the "VISTAS network" – we believe that you intended to reference this as the "IMPROVE network."

Chapter 12. Long-Term Strategy (LTS)

Section 12.7.2 cites the New Source Review program and Section 12.7.3 states that New Mexico considers its Prevention of Significant Deterioration (PSD) program as being protective of visibility impairment. We request that New Mexico state more specifically that regional haze goals for visibility improvement will be considered in New Source Review and PSD decisions.

New Mexico should discuss how its PSD plan supports its regional haze goals. This discussion is particularly important in light of the fact the State interprets its rule to say that FLMs will only be notified of PSD applications with 100km of the Class I area. Distance based limitations on notifications of PSD sources are not included in the Federal Rule. Furthermore, implementation of a 100km 'cutoff' for FLM notification of PSD actions is not protective of Class I visibility or other air quality related values, nor does it support New Mexico's efforts for a successful regional haze SIP.

The State is not clear on whether its smoke management plan (SMP) incorporates best management practices (BMPs), emission tracking, or enhanced practices to minimize impacts due to fire. More specifically, the State does not indicate that Class I areas are considered a sensitive receptor. Identifying Class I areas as sensitive receptors in an SMP is a necessary component to a regional haze SIP. In addition, the State identifies organic carbon as one of the primary pollutants responsible for its inability to meet the URP. Therefore, it is critically important that the State offer a robust discussion of how the SMP, BMPs, and emissions tracking will support the regional haze SIP.

Attachment

NPS Comments on the BART Determination by New Mexico Environment Department for Public Service Company of New Mexico's San Juan Generating Station, Units 1-4
August 17, 2010

San Juan Generating Station Source Description:
The San Juan Generating Station (SJGS) consists of four coal-fired electric generating units (EGUs) and associated support facilities. Coal for the units is supplied by the adjacent San Juan Mine and is delivered to the facility by conveyor. SJGS Units 1 and 2 are Foster Wheeler subcritical, dry-bottom, wall-fired boilers that operate in a forced draft mode and have a unit capacity of 360 and 350 MW, respectively. Units 3 and 4 are B&W subcritical, dry-bottom, opposed wall-fired boilers that operate in a forced draft mode, and each have a unit capacity of 544 MW. The presumptive limits for Nitrogen Oxide (NOx), which apply to each boiler (> 200 MW) at this large (>750 MW) facility are 0.23 lb/mmBtu for dry bottom, wall-fired boilers burning sub-bituminous coal.

Consent Decree:
On March 5, 2005,[1] Public Service of New Mexico (PNM) entered into a consent decree (CD) with the Grand Canyon Trust, the Sierra Club, and the New Mexico Environment Department (NMED) to settle alleged violations of the Clean Air Act. The consent decree required PNM to meet a particulate matter (PM) average emission rate of 0.015 lb/mmBtu (measured using EPA Reference Method 5), and a 0.30 lb/mmBtu emission rate for NO_X (daily rolling, thirty day average), for each of Units 1, 2, 3, and 4. As a result, PNM has installed new Low- NO_X burners (LNB) with overfire air (OFA) ports and a neural network (NN) system to reduce NO_X emissions, and pulse jet fabric filters to reduce the PM emissions. In 2009, SJGS ranked #10 in the nation with NO_X emissions of 18,359 tons.

Based upon the modeling results presented by NMED, the cumulative (three-year 98th percentile average) impact of SJGS' pre-consent decree emissions ranked fifth-worst of all of the BART sources we have evaluated at 24.47 dv, with the maximum (three-year 98th percentile average) impact of 4.38 dv occurring at Mesa Verde National Park. SJGS' post-consent decree impacts are now estimated by NMED to be 19.84 dv cumulatively, with the maximum (three-year 98th percentile average) impact of 3.57 dv occurring at Mesa Verde National Park. If the BART proposals of the four BART sources[2] with higher cumulative impacts are implemented as proposed, SJGS post-consent decree impacts would then rank fourth-worst (ahead of PGE Boardman after it installs Selective Catalytic Reduction (SCR)).

PNM's BART Analysis for NOx and PM:
PNM submitted the BART analysis for the SJGS to the NMED on June 6, 2007. The BART analysis was performed in two stages. First, a BART analysis was performed for the consent decree technologies being implemented at the SJGS. In the second stage of the BART analysis, additional control technology alternatives to the consent decree technologies were identified and evaluated. To determine the visibility improvements from both the consent decree technology upgrades and additional control technology, the NMED determined it was appropriate to review both pre-consent decree to consent decree visibility improvement and improvement projected from consent decree plus additional control technologies.

The Five-Step Process in the BART Analysis:

Step 1 – Identify All Available Retrofit Control Technologies
Step 2 – Eliminate Technically Infeasible Options

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[1] On May 5, 2004, EPA proposed new BART provisions and re-proposed the BART guidelines.
[2] Four Corners Power Plant, Navajo Generating Station, Centralia, PGE Boardman

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies
Step 4 – Evaluate Impacts and Document the Results
a) Costs of Compliance
b) Energy Impacts
c) Air quality environmental impacts
d) Non-air environmental impacts
e) Remaining useful life
Step 5 – Evaluate Visibility Impacts

Step 1 of the BART Analysis: Identification of All Available Retrofit Emissions Control Technologies

NOx Control Technologies
PNM identified the following available NOx control technologies:
1) Low NOx Burners, Overfire Air, and Neural Network
2) Selective Non Catalytic Reduction (SNCR)
3) Selective Catalytic Reduction (SCR) and SCR plus Sorbent Injection
4) SNCR/SCR Hybrid and SNCR/SCR Hybrid plus Sorbent Injection
5) Gas Reburn
6) Nalco Mobotec ROFA and Rotamix
7) NOxStar
8) ECOTUBE
9) PowerSpan ECO
10) Phenix Clean Combustion
11) e-SCRUB

PM Control Technologies
PNM identified the following technologies as available in their BART analysis for PM.
1) Flue Gas Conditioning with Hot-Side ESP
2) Pulse Jet Fabric Filter (PJFF)
3) Compact Hybrid Particulate Collector
4) Max-9 Electrostatic Fabric Filter

NPS: We agree that NMED has evaluated a comprehensive suite of control options.

Step 2 of the BART Analysis: Eliminate Technically Infeasible Control Technologies

NOx Control Technologies
PNM excluded the following NOx control technologies:

1) Selective Non Catalytic Reduction
PNM determined that SNCR technology was technically infeasible because the technology was unable to meet the presumptive limits for NOx; determined by EPA to be 0.23 lb NO_X/mmBtu for dry bottom, wall-fired boilers burning sub-bituminous coal. A vendor estimated that the technology could only achieve 0.24 lb NO_X/mmBtu. In order for the technology to achieve the presumptive limit, PNM stated that the ammonia slip limit would need to be raised from 5 ppm to 10 ppm, and that this higher ammonia slip posed additional operational problems.

The NMED did not agree with PNM's assertion that, because SNCR could not meet the presumptive limits, the technology should be eliminated as technically infeasible. Therefore, the NMED requested

PNM to perform the complete five-factor BART analysis required by the BART Guidelines on SNCR. PNM submitted the five-factor analysis of SNCR in a subsequent submittal dated May 30, 2008.

2) Natural Gas Reburn: PNM determined that the current boiler space inhibits sufficient residence time for the natural gas reburn zone.

3) NalcoMobotec ROFA (Rotating Over Fire Air) and Rotamix: PNM determined the Rotamix technology was technically infeasible due to limited application at coal-fired boilers equivalent to the size of Units 1-4 at SJGS. PNM determined ROFA technology was technically infeasible because ROFA is a variant of OFA, which at the time was being installed at Units 1-4 at SJGS.

The NMED did not agree with PNM's position that Rotamix has limited application at coal-fired boilers equivalent to the size of Units 1-4 at SJGS. The NMED did not agree that because ROFA is a variant of OFA, the technology can be eliminated as technically infeasible. Therefore, the NMED requested PNM to perform the complete five-factor analysis for ROFA and Rotamix. PNM performed the analysis and submitted the analysis in two subsequent submittals dated March 29, 2008, and August 29, 2008.

4) NOxStar: NOxStar currently has only one major installation in the US. In addition, PNM stated that in recent discussions the supplier has identified limited ability and willingness to market the commercial technology.

5) ECOTUBE: ECOTUBE has limited application to boilers similar to Units 1-4 at the SJGS.

6) PowerSpan: PowerSpan has not been demonstrated on large boilers, such as Units 1-4 at SJGS.

7) Phenix Clean Combustion: PNM determined that the Phenix Clean Combustion system is still in the demonstration and testing stage, and there are no commercial retrofits at facilities similar to SJGS.

8) e-SCRUB: PNM determined that the e-SCRUB technology has only one known medium scale installation with limited data.

PM Control Technologies
PNM excluded the following PM control technologies as technically infeasible:

1) Flue Gas Conditioning with Hot-Side ESP: Flue gas conditioning does improve collection efficiencies, but will not achieve an emission limit lower than the current PM limit in their air quality permit.

2) Compact Hybrid Particulate Collector: The compact hybrid particulate collector does not provide a performance guarantee lower than the current permitted limit for PM.

3) Max-9 Electrostatic Fabric Filter: The Max-9 electrostatic fabric filter has been installed in a small-sized utility boiler, but there are no commercial installations of a similar size to Units 1-4 at SJGS.

During the NMED review of available PM control technologies, the NMED requested PNM to perform a complete five-factor BART analysis on Wet Electrostatic Precipitator (WESP). The NMED believes this technology should have been identified as technically feasible in Step 1 of the PM BART analysis. PNM performed a complete five-factor BART analysis on WESP and PJFF and submitted this information in a subsequent submittal dated August 28, 2008.

NPS: We agree with NMED's selection of technically-feasible control options.

Step 3 of the BART Analysis: Evaluate Control Effectiveness of Remaining Control Technologies

PNM contracted with Black & Veatch (B&V) to determine the control effectiveness of each remaining available NO_X and PM control technology for Units 1-4. For the LNB/OFA+SCR option, PNM assumed 0.07 lb/mmBtu; this represents only a 77% reduction from the current LNB/OFA 0.30 lb/mmBtu emission rate.

NPS: PNM has **underestimated the ability of SCR to reduce emissions.** EPA's Clean Air Markets (CAM) data and vendor guarantees[3] show that SCR can typically meet 0.05 lb/mmBtu (or lower) on an annual average basis.[4] We are including 2007 - 2009 CAM data (**electronic Appendix A**) that shows that SCR can achieve year-round emissions of 0.05 lb/mmBtu or lower at 26 coal-fired EGUs, eight of which are dry-bottom, wall-fired units like SJGS. Although we believe that SCR is capable of even lower annual NO_x emissions at SJGS, we will continue to assume 0.05 lb/mmBtu in our analyses to reflect our understanding of vendor guarantees.[5] PNM has not provided any documentation or justification to support the higher values used in its analyses.

We are also presenting information from industry sources that supports our understanding that SCR can achieve 90% reduction[6] and reduce emissions to 0.05 lb/mmBtu or lower[7] on coal-fired boilers. For example, according to the Institute of Clean Air Companies white paper titled "Selective Catalytic Reduction (SCR) Control of NO_x Emissions from Fossil Fuel-Fired Electric Power Plants" (published in May 2009), "By proper catalyst selection and system design, NO_X removal efficiencies exceeding 90 percent may be achieved." And, according to the June 13, 2009 "Power" magazine article "Air Quality Compliance: Latest Costs for SO_2 and NO_X Removal (effective coal clean-up has a higher–but known–price tag)" *by* Robert Peltier, "An excellent example of the significant investment many utilities have made over the past decade is American Electric Power (AEP), one of the largest public utilities in the U.S. with 39,000 MW of installed capacity with 69% of that capacity coal-fired. AEP is under a New Source Review (NSR) consent decree signed in 2007 that requires the utility install air quality control systems to reduce NO_X by 90%..."

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[3] Minnesota Power has stated in its Taconite Harbor BART analysis that "The use of an SCR is expected to achieve a NO_X emission rate of 0.05 lb/mmBtu based on recent emission guarantees offered by SCR system suppliers."

[4] For example, Salt River Project is using 0.05 lb/mmBtu as the design basis for its revised analysis of adding SCR at its Navajo Generating Station.

[5] A NO_X limit of 0.06 lb/mmBtu is appropriate for LNB/OFA+SCR for a 30-day rolling average, and 0.07 lb/mmBtu for a 24-hour limit and for modeling purposes, but a lower rate (e.g., 0.05 lb/mmBtu or lower) should be used for annual average and annual cost estimates.

[6] For example, please see the May 2009 Institute of Clean Air Companies white paper titled "Selective Catalytic Reduction (SCR) Control of NO_x Emissions from Fossil Fuel-Fired Electric Power Plants" and the June 13, 2009, "Power" magazine article "Air Quality Compliance: Latest Costs for SO2 and NOx Removal (effective coal clean-up has a higher–but known–price tag)" *by* Robert Peltier. http://www.masterresource.org/2009/06/air-quality-compliance-latest-costs-for-so2-and-nox-removal-effective-coal-clean-up-has-a-higher-but-known-price-tag/

[7] 12/15/09 presentation by Rich Abram of Babcock Power to the Minnesota Pollution Control Agency. Not only does Babcock Power say that SCR can achieve 0.05 lb/mmBtu, they are currently designing systems to go as low as 0.02 lb/mmBtu.

Step 4 of the BART Analysis: Perform Impacts Analysis of Remaining Control Technologies

B&V prepared the design parameters and developed estimates of capital and annual costs for applications of SCR, SCR/SNCR Hybrid, ROFA, Rotamix, ROFA/Rotamix, PJFF, and WESP technologies. B&V relied on a number of sources to prepare the design parameters, including information from the Nalco Mobotec equipment vendors, EPA cost manuals, engineering and performance data, and B&V's own in-house engineering estimates.

PNM evaluated the energy impacts, non-air quality environmental impacts, and remaining useful life of all additional technically feasible control options for NO_X and PM. Following the initial submittal, the NMED made additional requests for information on the impact analysis for SCR, SNCR, ROFA, Rotamix and WESP, and for further consideration of inherent and additional control of SO_3 from both the SCR and SCR/SNCR Hybrid technology.

SCR Costs

The NMED reviewed the original cost analysis for SCR technology and subsequently requested PNM to provide additional information on the basis of their cost analysis of SCR technology. In response to the request, B&V provided additional clarification for the cost analysis for SCR technology and submitted it to the NMED on March 29, 2008. The submittal discussed how the OAQPS control cost manual (Cost Manual) is an insufficient method for determining actual costs of retrofitting the SJGS with SCR and provided a comparison between cost estimation based on the OAQPS manual and the B&V provided estimate.

NPS: The B&V document discussed the need to escalate costs estimated using the Cost Manual, and we agree. We have been advised by OAQPS[8] to use the Chemical Engineering Plant Cost Index (CEPCI) which has risen from 389.5 in 1998 (the Cost Manual SCR reference date) to 521.9 in 2009. Application of the CEPCI indices results in an escalation of 1998 costs to 2009 by a factor of 1.34. It appears that PNM has escalated costs from 1998 to 2007 by a factor of 1.66.

We are not sure how B&V concluded that "the Cost Manual is geared more towards developing costs for new units than retrofitting controls on existing units." The Cost Manual clearly contains an adjustment for retrofit situations.

"B&V takes guidance from EPA's CUECost program in developing the costs of SCR systems," EPA has explicitly advised use of the Cost Manual instead of CUECost.[9]

PNM is including a separate cost for Owner's 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." In its May 10, 2010, formal comments to the

[8] July 21, 2010, e-mail from Larry Sorrels of EPA OAQPS to Don Shepherd: "On cost indexes, I prefer the CEPCI for escalating/deescalating costs for chemical plant and utility processes since this index specifically covers cost items that's pertinent to pollution control equipment (materials, construction labor, structural support, engineering & supervision, etc.).The Marshall & Swift cost index is useful for industry-level cost estimation, but is not as accurate at a disaggregated level when compared to the CEPCI. Thus, I recommend use of the CEPCI as a cost index where possible."

[9] November 7, 2007, statement from EPA Region 8 to the North Dakota Department of Health: The SO_2 and PM cost analyses were completed using the CUECost model. According to the BART Guidelines, in order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual. Therefore, these analyses should be revised to adhere to the Cost Manual methodology.

North Dakota Department of Health, EPA rejected the inclusion of "Owner Costs" in the analysis of adding SCR to the Milton R. Young (MRYS) power plant:

> As noted above, the total direct capital costs used by B&McD appears to be overestimated. A large portion of this discrepancy comes from the "other" costs added by B&McD (Table 2) that are not included in the Control Cost Manual. These appear to be strictly contingencies and accounting items which would not be at all unique to MYRS and, therefore, are not justified in the analysis. These accounting items are unauthorized under the Control Cost Manual, create an unlevel playing field for comparison with other BACT analyses and alone account for an increase in capital costs from the Control Cost Manual by a factor of 1.6.

In section 2.16, "Construction Indirects", PNM discusses the "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." PNM then states that, "The Cost Manual does not address these costs in any way yet these are real costs that will be incurred in order to support the direct cost of installing the SCR system." We believe that the Cost Manual does indeed, address these costs as discussed below.

Chapter 2. Cost Estimation: Concepts and Methodology
2.3.1 Elements of Total Capital Investment
Indirect installation costs include such costs as engineering costs; construction and field expenses (i.e., costs for construction supervisory personnel, office personnel, rental of temporary offices, etc.); contractor fees (for construction and engineering firms involved in the project); start-up and performance test costs (to get the control system running and to verify that it meets performance guarantees); and contingencies.

Chapter 2, Selective Catalytic Reduction
2.4.1 Total Capital Investment, Indirect Capital Costs
Indirect installation costs are those associated with installing and erecting the control system equipment but do not contribute directly to the physical capital of the installation. This generally includes general facilities and engineering costs such as construction and contractor fees, preproduction costs such as startup and testing, inventory capital and any process and project contingency costs.

In his book Estimating Costs of Air Pollution Control, William Vatavuk (who was primarily responsible for the Cost Manual while at EPA) provides this insight regarding Indirect Costs:

> "The indirect (soft) installation costs comprise engineering costs, construction and field expenses (e.g., rental of trailers and like equipment), contractor fees (for firms involved in the project), startup and performance tests (to get the control system running and to verify that it meets the vendor's guarantees), and contingencies."

PNM states that "there are two main reasons that the Cost Manual was not used. First, the price of SCR systems (and other AQC retrofits) has increased dramatically in the past 10 years, and especially since 2005. Second, the Cost Manual does not include many categories of equipment and construction that are required for the complete installation of an SCR system consistent with common industry practices." However, a common-sense application of an escalation factor (such as the CEPCI) to the Direct Capital Cost remedies the first problem, and we disagree that the Cost Manual approach omits significant costs.

We note that, in NMED's December 21, 2007, letter to PNM, the NMED requested that the cost estimate for SCR be performed using the OAQPS Cost Manual. While PNM presented an extensive comparison of its method for estimating capital costs versus that of the Cost Manual, we were unable to find a similar discussion regarding annual costs. The only information we could find regarding annual costs (which are critical to the cost-benefit analyses), was contained in PNM's Appendix B "Details of Cost Calculation Using OAQPS Cost Manual."

We also performed a parallel cost estimate using the Cost Manual for SJGS Unit 3 (see electronic attachment **Appendix B**). However, we used the CEPCI ratio and catalyst[10] and ammonia costs obtained from vendor quotes and from Salt River Project's BART analysis for the Navajo Generating Station because they were better-documented and appeared more realistic. Our 2009 Direct Capital Cost was $28 million (versus PNM's $37 million in 2007) and our Total Capital Investment was $39 million (versus PNM's $52 million). The differences between the two sets of estimates are primarily due to the escalation factors used.

Regarding annual costs, using its 1998 Direct Capital Cost (which yielded a Total Capital Investment and Indirect Annual Cost that is too low), PNM estimated a Direct Annual Cost of $3.5 million, an Indirect Annual Cost of $3.0 million and a Total Annual Cost of $6.4 million. Using our 2009 Direct Capital Cost, we estimated a Direct Annual Cost of $3.0 million, an Indirect Annual Cost of $3.7 million and a Total Annual Cost of $6.7 million.

PNM has overestimated the cost of adding SCR to all four units at SJGS. A useful metric for estimating the Total Capital Investment (TCI) is the SCR cost expressed in $/kW. The TCI costs estimated by PNM are shown below:

Unit	SJGS #1	SJGS #2	SJGS #3	SJGS #4
Capital Cost (TCI)	$156,805,000	$ 169,251,000	$ 215,568,000	$ 199,558,000
Capital Cost ($/kW)	$ 436	$ 484	$ 396	$ 367

Further evidence that PNM has overestimated its SCR costs can be found in a June 2009 article in "Power" magazine:[11]

> "One more current data set is the historic capital costs reported by AEP averaged over several years and dozens of completed projects. For example, AEP reports that their historic average capital costs for SCR systems are $162/kW for 85% to 93% NO_X removal..."
>
> "…historical data finds the installed cost of an SCR system of the 700MW-class as approximately $125/kW over 22 units with a maximum reported cost of $221/kW in 2004 dollars. This data was reported prior to the dramatic increase in commodity prices of 14% per year average experienced from 2004 to 2006 (from the FGD survey results). Applying those annual increases to the 2004 estimates for three years (from the date of the survey to the end of 2007) produces an average SCR system installed cost of $185/kW…"

[10] 2010 vendor quotes for low-oxidation catalyst ranged from $4,895 to $6,250 per cubic meter.

[11] June 13, 2009, "Power" magazine article "Air Quality Compliance: Latest Costs for SO2 and NOx Removal (effective coal clean-up has a higher–but known–price tag)" *by* Robert Peltier. http://www.masterresource.org/2009/06/air-quality-compliance-latest-costs-for-so2-and-nox-removal-effective-coal-clean-up-has-a-higher-but-known-price-tag/

> "Overall, costs were reported to be in the $100 to $200/kW range for the majority of the systems, with only three reported installations exceeding $200/kW."

Five industry studies conducted between 2002 and 2007 have reported the installed unit capital cost of SCRs, or the costs actually incurred by owners, expressed in dollars per kilowatt. These actual costs are lower than estimated by PNM for SJGS.

The first study evaluated the installed costs of more than 20 SCR retrofits from 1999 to 2001. The installed capital cost ranged from $106 to $213/kW, converted to 2007 dollars.[12] Costs are escalated through using the Chemical Engineering Plant Cost Index ("CEPCI").

The second survey of 40 installations at 24 stations reported a cost range of $76 to $242/kW, converted to 2007 dollars.[13]

The third study, by the Electric Utility Cost Group, surveyed 72 units totaling 41 GW, or 39% of installed SCR systems in the U.S. This study reported a cost range of $118/kW to $261/kW, converted to 2007 dollars.[14]

A fourth study, presented in a course at PowerGen 2005, reported an upper bound range of $180/kW to $202/kW, converted to 2007 dollars.[15]

A fifth summary study, focused on recent applications that become operational in 2006 or were scheduled to start up in 2007 or 2008, reported costs in excess of $200/kW on a routine basis, with the highest application slated for startup in 2009 at $300/kW.[16]

Thus, the overall range for these industry studies is $50/kW to $300/kW. The upper end of this range is for highly complex retrofits with severe space constraints, such as Belews Creek, reported to cost $265/kW,[17] or Cinergy's Gibson Units 2-4. Gibson, a highly complex, space-

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[12] Bill Hoskins, Uniqueness of SCR Retrofits Translates into Broad Cost Variations, Power Engineering, May 2003. Ex. 2. The reported range of $80 to $160/kW $123 - $246/kW was converted to 2008 dollars ($116 - $233/kW) using the ratio of CEPCI in 2008 to 2002: 575.4/395.6.

[13] J. Edward Cichanowicz, Why are SCR Costs Still Rising?, Power, April 2004, Ex. 3; Jerry Burkett, Readers Talk Back, Power, August 2004, Ex. 4. The reported range of $56/kW - $185/kW was converted to 2008 dollars ($83 - $265/kW) using the ratio of CEPCI for 2008 to 1999 (575.4/.390.6) for lower end of the range and 2008 to 2003 (575.4/401.7) for upper end of range, based on Figure 3.

[14] M. Marano, Estimating SCR Installation Costs, Power, January/February 2006. Ex. 5. The reported range of $100 - $221/kW was converted to 2008 dollars ($130 - $286/kW) using the ratio of CEPCI for 2008 to 2004: 575.4/444.2. http://findarticles.com/p/articles/mi_qa5392/is_200602/ai_n21409717/print?tag=artBody;col1

[15] PowerGen 2005, Selective Catalytic Reduction: From Planning to Operation, Competitive Power College, by Babcock Power, Inc. and LG&E Energy, December 2005, Ex. 6. The reported range of $160 - $180/kW) was converted to 2008 dollars ($197 - $221/kW) using the ratio of CEPCI for 2008 to 2005 (575.4/468.2).

[16] J. Edward Cichanowicz, Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies, June 2007, pp. 28-29, Figure 7-1 (Ex. 1).

[17] Steve Blankinship, SCR = Supremely Complex Retrofit, Power Engineering, November 2002, Ex. 7. The unit cost:($325,000,000/1,120,000kW)(608.8/395.6)=$290/kW. http://pepei.pennnet.com/display_article/162367/6/ARTCL/none/none/1/SCR-=-Supremely-Complex-Retrofit/

constrained retrofit in which the SCR was built 230 feet above the power station using the largest crane in the world,[18] only cost $251/kW in 2007 dollars.[19]

All of PNM's TCI estimates, when reduced to $/kW, far exceed even the highest costs reported by the industry. In addition to its high estimates for Direct Capital Cost (DCC), it appears that PNM has applied much higher ratios to the DCC than used by the Cost Manual to estimate Indirect Installation Costs. (Please see our cost analyses in **electronic Appendix B**.) For example, the PNM estimates for Total Indirect Installation Costs are typically 50% of the DCC, compared to the 20% ratio used by the Cost Manual. PNM's Total Plant Costs are typically 170% of the DCC, versus the 138% used by the Cost Manual. And, PNM's Total Capital Investment is typically 217% of the DCC versus the Cost Manual's 141% ratio.

In addition to the unusually high ratios used by PNM to estimate its TCI, the estimates generated by PNM for its operating costs are also consistently higher than corresponding estimates generated by the Cost Manual.

- PNM used a 3% TCI factor instead of the Cost Manual's 1.5% to estimate its annual maintenance costs.
- PNM's reagent costs (per ton) are much higher than any we have seen elsewhere.
- PNM's power costs are much higher than the Cost Manual estimate.
- PNM has assumed a two-year catalyst life instead of the typical three years.
- PNM's estimates are based upon achieving 0.07 lb/mmBtu, which represents 77% NO_x reduction from the Consent Decree limit of 0.30 lb/mmBtu to be achieved by combustion controls. Although modern SCR systems are typically designed to achieve 90+% NO_x reductions, we assumed a 0.05 lb/mmBtu (an 83% reduction) "target" for SCR based upon the performance of the boiler retrofits discussed above.

These issues collectively result in PNM's extraordinarily high Total Annual Cost and Cost/ton estimates.

As recommended by the BART Guidelines, we applied the OAQPS Control Cost Manual and industry data to SJGS. (Please see the workbooks in **electronic Appendix B**.) We assumed that addition of SCR would reduce NO_x to an annual emission rate of 0.05 lb/mmBtu.[20] We also assumed that Total Capital Investment for each of the SJGS units would be $200/kW, which appears to be the current industry average for adding SCR. Using as much of the PNM information as was relevant, we estimated Direct Annual Costs, Total Annual Costs, and Costs per Ton of NO_X removed.

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[18] Standing on the Shoulder of Giants, Modern Power Systems, July 2002, Ex. 8.

[19] McIlvaine, NOX Market Update, August 2004, Ex. 9. SCR was retrofit on Gibson Units 2-4 in 2002 and 2003 at $179/kW. Assuming 2002 dollars, this escalates to ($179/kW)(608.8/395.6) = $275.5/kW. http://www.mcilvainecompany.com/sampleupdates/NoxMarketUpdateSample.htm

[20] Our review of CAM data (**see electronic Appendix A**) for eastern wall-fired EGUs retrofitted with SCR indicates that they can meet 0.05 lb/mmBtu on an annual average basis.

Unit	SJGS #1	SJGS #2	SJGS #3	SJGS #4
Controlled Emissions (tpy)	730	704	1,094	1,140
Emissions Reduction (tpy)	3,649	3,520	5,468	5,698
Capital Cost (TCI)	$ 72,000,000	$ 70,000,000	$ 108,800,000	$ 108,800,000
Capital Cost ($/kW)	$ 200	$ 200	$ 200	$ 200
Direct Annual (O&M) Cost	$ 2,760,029	$ 2,681,266	$ 4,169,103	$ 4,238,137
Total Annualized Cost	$ 9,556,319	$ 9,288,771	$ 14,439,054	$ 14,508,087
Cost-Effectiveness ($/ton)	$ 2,619	$ 2,639	$ 2,641	$ 2,546

Installation of SCR is typically done in conjunction with upgrading of combustion controls, and the overall costs and benefits are expressed as a "package." However, PNM has installed the combustion controls to comply with the Consent Decree, so the costs have been split between the relatively inexpensive combustion control segment and the relatively expensive SCR segment. The table below shows the total NO_X-control "package" costs.

Unit	SJGS #1	SJGS #2	SJGS #3	SJGS #4
Emissions Reduction (tpy)	5,532	6,181	8,180	8,547
Capital Cost	$ 86,500,000	$ 84,126,000	$ 121,515,000	$ 121,670,000
Capital Cost ($/kW)	$ 240	$ 240	$ 223	$ 224
Annualized Cost	$ 10,978,319	$ 10,666,771	$ 15,679,054	$ 15,764,087
Cost-Effectiveness ($/ton)	$ 1,985	$ 1,726	$ 1,917	$ 1,844

- The Total Capital Investment would be approximately $414 million.
- The Total Annual Cost to remove over 28,000 tons/yr would be $53 million or $1,900/ton.
- The controlled NO_X emission rate would be 3,700 tpy, and SJGS would become the 235th largest NO_x source in the U.S.

A unit-by-unit compilation of our detailed cost estimates is presented in (electronic file) **Appendix B**.

Step 5 of the BART Analysis: Visibility Impacts Analysis of Remaining Control Technologies

The modeling approach followed the requirements described in the WRAP's BART modeling protocol, *CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States dated August 15, 2006*. The refined modeling methodology is described in detail below.

Modeling Results

From the air dispersion modeling methodology outlined in the previous section, a CALPUFF model run was conducted for the following control technologies for each unit during the BART engineering analysis, including the pre-consent decree: Consent Decree, Rotamix, ROFA/Rotamix, ROFA, SCR/SNCR Hybrid (SCR/SNCR Hybrid with Inherent SO_3 Removal), SCR with Sorbent (SCR with Inherent SO_3 Removal and Sorbent Injection), PJFF, and WESP. To simplify the quantity of the modeling results, total visibility impacts at all 16 Class I areas were used to make comparisons of each control technology's performance.

NPS: We commend NMED for its thoroughness in modeling the viable NO_X control options and for its presentation of those results in a way that illustrates the cumulative benefits of improving visibility across all 16 Class I areas. We suggest that modern low-oxidation catalysts coupled with the inherent sulfuric acid mist removal capabilities of the air-heater, baghouse, and wet scrubber would result in minimal additional sulfuric acid mist emissions. For example, when we applied the EPRI method for estimating sulfuric acid mist emissions (see electronic **Appendix C**), we found that addition of SCR with a 0.5% oxidation catalyst[21] would add only 3 – 6 lb/hr of sulfuric acid mist emissions. It appears that the modeling results that most-closely represent the likely emissions after addition of SCR are from the SCR with sorbent injection case.

Visibility Impact of NOx Control Technology

The results of the facility-wide analysis indicate the installation of SCR with sorbent control technology results in maximum visibility improvement at all of the 16 Class I areas when compared to the impact of the other control options. It is important to note that SCR with sorbent control technology improves visibility more significantly than the other control options at Mesa Verde National Park, which is the closest, and most impacted, Class I area to the facility.

NPS: Modeling results for the SCR with inherent SO_3 removal and sorbent injection indicate that this option would reduce cumulative impacts by 7.9 dv (as illustrated by NMED Figure 4) with a 1.2 dv improvement at Mesa Verde NP.

Visibility Impact of PM Control Technology

The visibility modeling performed for the WESP control option was performed on a facility-wide and unit-by-unit basis. The results of the facility-wide analysis demonstrate a net improvement of 0.62 dv at Mesa Verde National Park and 0.14 dv improvement at San Pedro Parks Wilderness. The amount of visibility improvement at all other Class I areas was equal to or less than 0.1 dv improvement.

The results of the unit-by-unit impact analysis demonstrate a 0.21 dv improvement for Units 3 and 4 at Mesa Verde National Park. However, all other impact analyses show less than a 0.1 dv improvement at any of the Class I areas for Units 1-4.

NMED Selection of BART for PM and NOx

In accordance with Section 169A(g)(7) of the Clean Air Act, the NMED considered the following five statutory factors in the BART analysis for the SJGS: (1) the costs of compliance; (2) energy and nonair quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably by anticipated to result from the use of such technology.

PM BART Determination

Based on the five factor analysis, the NMED has determined that BART for Units 1-4 for PM is existing PJFF technology and the existing emission rate of 0.015 lb/mmBtu. The NMED's determination of BART was based on the following results of the full five factor analysis:

1) Each of Units 1-4 is equipped with PJFF and is subject to a federally-enforceable emission limit of 0.015 lb PM/mmBtu.

2) The NMED reviewed both the cost-effectiveness and incremental cost-effectiveness of additional control technology (WESP) and found these costs to be excessive.

3) There are additional energy impacts associated with the WESP technology and the NMED considers these costs to be reasonable.

[21] as assumed by Salt River Project for SCR at its Navajo Generating Station

4) The NMED reviewed the visibility improvement that resulted from the installation of the consent decree technology (PJFF and LNB/OFA) and that would result from the addition of WESP technology. The NMED determined that on a facility-wide basis the visibility improved by 1.06 deciviews (dv) from the installation of the consent decree technology at Mesa Verde National Park (Mesa Verde). The installation of WESP would result in a facility-wide improvement of 0.62 dv at Mesa Verde. Improvements on a unit-by-unit basis at all Class I areas showed very minor improvements, usually less than 0.1 dv.

NOx BART Determination

Based on the five factor analysis, the NMED has determined that BART for Units 1-4 for NOx is SCR plus sorbent injection and an emission rate between 0.03 and 0.07 lb/mmBtu. The NMED's determination of BART was based on the following results of the five factor analysis:

1) The PNM cost-effectiveness of SCR + sorbent technology ranges from $5,946/ton for Unit 4 to $7,398/ton for Unit 2, and the incremental cost-effectiveness of SCR + sorbent ranges from $1,691/ton for Unit 4 to $4,431/ton for Unit 2. Although the NMED finds these values acceptable, they are conservative as demonstrated by the following evidence. These values are based on: (a) implementing the SCR projects separately at each unit (expected synergies between the construction projects should lower these costs); (b) incorporating the cost of SCR bypass at each unit without sufficient justification for why alternative fuels cannot be considered thus eliminating the need of the bypass altogether, or why the bypass for Units 3 and 4, two baseload units, could not be retrofitted with a catalyst that could accommodate occasional startups, eliminating their bypass; (c) including the cost of a full balanced-draft conversion at each unit without sufficient justification of the 10 inches of additional pressure drop;[22] (d) including labor costs at the rates reflective of pre-recession 2007 values; (e) including the cost of purchase power for 5 full weeks at each unit,[23] despite lack of detailed schedule provided by PNM; (f) PNM's inclusion of various over-head and other factors without appropriate basis; and (g) an SCR removal efficiency of 77%, which significantly underestimates the tons of NOx that can be removed (SCR can typically achieve 90% removal efficiency). Additionally, PNM assumed that SO2 to SO3 conversion of 1% due to the SCR catalyst. Lower conversion catalysts are available, leading to lower sorbent and capital costs.

The NMED does not necessarily agree with the cost-estimates supplied in the impact analysis and finds some of the costs have not been fully justified. Cost estimates for SCR supplied by the NPS were consistently three to over four times lower than the cost estimates supplied by PNM.

The NMED expects the actual costs of SCR technology to be between the two cost-estimates supplied by PNM and NPS.

2) The above notwithstanding, the cost-effectiveness and incremental cost-effectiveness of SCR plus sorbent technology calculated by PNM is considered reasonable by the NMED. These costs are in line with acceptable cost-effectiveness values for BACT determinations, which involve a similar control technology evaluation process. With the considerations highlighted above, the cost-estimates would likely be lower. Thus, the price per ton of NOx removal would be lower.

3) The Guidelines state that regulatory agencies should require utility boilers to meet the presumptive limits, unless an agency determines that an alternative control is justified based on the consideration of

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[22] ***NPS:*** The OAQPS Control Cost Manual estimates a 7" H_2O pressure drop across the SCR reactor and duct.

[23] **NPS:** Salt River Project has estimated that addition of SCR at each unit at its Navajo Generating Station (NGS) would require eight weeks, with seven days of lost generation. It is unlikely that addition of SCR at SJGS would be as complex and time-consuming as at NGS.

statutory factors. The presumptive limit for NOx at Units 1-4 at the SJGS is 0.23 lb/MMbtu. However, in light of the reasonable cost-effectiveness and incremental cost-effectiveness, acceptable energy impacts and non-air quality environmental impacts, and visibility improvement resulting from installation of SCR plus sorbent, the NMED has determined BART as SCR plus sorbent injection.

4) Annual NOx emissions from the facility will be reduced by 16,100 tons from SCR plus sorbent, at the assumed 0.07 lb/MMbtu value used by PNM. At 0.03 lb/mmBtu, the NOx emissions reduction from the facility will be greater still.

5) The NMED reviewed the visibility improvement that resulted from the installation of the SCR plus sorbent technology at the 0.07 lb/mmBtu NOx level. The NMED determined that on a facility-wide basis the visibility improved by 1.34 deciviews (dv) from the installation of SCR plus sorbent technology at Mesa Verde, 0.88 dv at San Pedro, 0.75 dv at Bandelier, 0.73 dv at Capitol Reef, 0.67 dv at Canyonlands, 0.59 dv at Arches, 0.59 dv at Weminuche, 0.52 dv at Black Canyon, 0.49 dv at La Garita, 0.49 dv at West Elk, 0.44 dv at Grand Canyon, 0.43 dv at Pecos, 0.40 dv at Wheeler Peak, 0.34 dv at Petrified Forest, 0.31 at Great Sand Dunes, and 0.28 dv at Maroon Bells. Visibility improvements will be greater using a NOx level of 0.03 lb/mmBtu.

6) Again using a NOx value of 0.07 lb/MMbtu, SCR plus sorbent technology reduced the number of days that each Unit exceeded a 0.5 dv impact. For Unit 1, the number of days exceeding 0.5 dv was reduced from 46 days to 16 days; Unit 2's impact decreased from 46 days to 16 days; Unit 3's impact decreased from 68 days to 31 days; and Unit 4's impact decreased from 67 days to 29 days. Impacts would be further reduced at a NOx limit of 0.03 lb/mmBtu.

7) The installation of SCR plus sorbent technology will result in additional energy impacts and nonair environmental impacts, and the remaining useful life of 20 years did not further impact costs. None of the additional energy or non-air environmental impacts prohibit selection of this technology.

NPS: We commend NMED for the thoroughness and the critical approach of its analysis. We have provided additional data from EPA's Clean Air Markets Database showing that SCR can achieve much lower NO_X emission rates on an annual basis[24] than used by PNM in its analyses, which supports NMED's concern that PNM has underestimated the benefits of adding SCR. We have also provided SCR cost information from industry sources and publications that indicate that PNM's estimates of the costs of adding SCR at SJGS would far exceed any costs actually experienced at an EGU in the US. We have also provided information, based upon EPA's OAQPS Control Cost Manual that indicates that PNM has overestimated its annual costs to operate and maintain SCRs at SJGS. This supports NMED's concern that PNM has overestimated the cost of installing and operating SCR.

[24] Please see our discussion of short-term NO_X emissions contained in electronic **Appendix D**.

Visibility Cost-Effectiveness Analyses

Unit	1	2	3	4
Visibility Impact before CD (dv at Max Class I)	1.66	1.66	2.08	2.09
Visibility Impact after CD (dv at Max Class I)	1.34	1.34	1.73	1.72
Visibility Impact before CD (dv at Summed Class I)	7.47	7.50	10.54	10.65
Visibility Impact after CD (dv at Summed Class I)	5.92	5.89	8.31	8.20
Visibility Impact after BART (dv at Max Class I)	0.67	0.67	0.94	0.92
Visibility Improvement (dv at Max Class I)	0.67	0.67	0.79	0.80
Cost-Effectiveness ($/98th % dv at Max Class I)	$ 14,334,479	$ 13,863,837	$18,200,488	$18,135,109
Visibility Impact after BART (dv at Summed Class I)	2.82	3.08	4.07	4.01
Visibility Improvement (dv at Summed Class I)	3.10	3.10	4.24	4.19
Cost-Effectiveness ($/98th % dv at Summed Class I)	$ 3,079,373	$ 2,993,159	$3,402,762	$3,459,798
Total Visibility Improvement (dv at Max Class I)	0.99	0.99	1.14	1.17
Total Cost-Effectiveness ($/98th % dv at Max Class I)	$ 11,089,211	$ 10,810,916	$13,753,556	$13,512,075
Total Visibility Improvement (dv at Summed Class I)	4.65	4.41	6.47	6.65
Total Cost-Effectiveness ($/98th % dv at Summed Class I)	$ 2,359,238	$ 2,416,942	$2,422,099	$2,371,728

We estimate that, as shown in the table above, addition of SCR to SJGS Units #1 - #4 represents BART because it would result in cost-effectiveness values that fall well within the $13 million - $20 million **average** cost/deciview proposed as BART by other sources and states.

We note that NMED has presented a range of 0.03 – 0.07 lb/mmBtu as a potential NO_X limit. We assume that this would be a 30-day rolling average limit, and suggest that 0.06 lb/mmBtu would be appropriate based upon a sampling of 228 monthly averages[25] taken from the 26 EGUs with annual NO_X emissions less than 0.06 lb/mmBtu. 214 of those monthly averages were less than 0.07 lb/mmBtu, which indicates that a limit of 0.06 lb/mmBtu could be achieved 94% of the time by these EGUs.

[25] We deleted any month with less than 360 hours of data.