United States Department of the Interior
NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

TAKE PRIDE IN AMERICA

IN REPLY REFER TO:

March 31, 2011

N3615 (2350)

Mr. Guy Donaldson, Chief
Air Planning Section (6PD-L)
Environmental Protection Agency Region 6
1445 Ross Avenue
Suite 1200
Dallas, Texas 75202-2733

EPA Docket No. EPA-R06-OAR-2010-0846

Dear Mr. Donaldson:

This letter responds to the Environmental Protection Agency's (EPA's) Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology (BART) Determination as proposed in the Federal Register on January 5, 2011.

The National Park Service, in consultation with the Fish and Wildlife Service, has conducted a substantive review of EPA's proposed actions for interstate transport and proposed BART determination for the San Juan Generating Station (SJGS). We agree with EPA's proposed emissions limit for sulfur dioxide of 0.15 lbs/MMBtu on a 30-day rolling average for units 1 through 4 to limit interstate transport. We commend EPA for the thorough review of BART controls for nitrogen oxide (NO_x) emissions. We agree with EPA that NO_x BART for SJGS is Selective Catalytic Reduction technology.

We appreciate the opportunity to work closely with EPA to improve visibility conditions at our National Parks and Wilderness Areas. For further information regarding our comments, please contact Don Shepherd at (303) 969-2075.

Sincerely,

John Bunyak

John Bunyak
Chief, Policy, Planning and Permit Review Branch

Enclosure

cc:
Joe Kordzi
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1445 Ross Avenue
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Dallas, Texas 75202-2733

NPS Comments on the Best Available Retrofit Technology (BART) Determination by EPA for Public Service Company of New Mexico's San Juan Generating Station, Units 1-4
March 31, 2011

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 BART limit for Nitrogen Oxide (NOx), which applies to each boiler (> 200 MW) at this large (>750 MW) facility, is 0.23 lb/mmBtu (30-day rolling average) 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 2010, SJGS ranked #15 in the nation with NO_X emissions of 15,775 tons. Furthermore, the cumulative visibility impact of SJGS at the surrounding Class I areas ranks it among the sources with the highest impacts we have reviewed under the BART program.

NO_X BART Analysis

We shall confine our comments to NO_X, skip the first two steps:
Step 1: Identify All Available Retrofit Technologies
Step 2: Eliminate All Technically Infeasible Control Options
and focus upon the analysis of Selective Catalytic Reduction (SCR) by following the remaining steps in the BART process.

Step 3: 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 (annual average); this represents only a 77% reduction from the current LNB/OFA 0.30 lb/mmBtu emission rate.

[1] On May 5, 2004, EPA proposed new BART provisions and re-proposed the BART guidelines.

NPS: PNM has **underestimated the ability of SCR to reduce emissions.** For example, B&V assumed that SCR could achieve 0.05 lb/mmBtu (annual average) when evaluating retrofitting of SCR at the Craig power plant in Colorado.[2]

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 2010 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, eleven of which are dry-bottom, wall-fired units like SJGS. Although SCR may be 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%..."

Step 4: Perform Impacts Analysis of Remaining Control Technologies—SCR Costs

One metric for estimating the Total Capital Investment (TCI) is the SCR cost expressed in $/kW. The TCI costs estimated by PNM (in 2010 $) are shown below:

[2] Exhibit 16 - Craig Stations 1, 2, and 3 November 2010 Black & Veatch Report, Tables 2-1, 2-1, 4-6,4-8, 7-7, 7-8, "Selective Catalytic Reduction System"

[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.

Unit	SJGS #1	SJGS #2	SJGS #3	SJGS #4
Capital Cost[8] (TCI)	$184,143,000	$ 198,790,000	$ 248,416,000	$ 230,089,000
Capital Cost ($/kW)	$ 512	$ 568	$ 457	$ 423

The B&V 10/22/10 Cost Analysis escalated the original May 2007 costs to September 2010 using data for certain materials and equipment from the U.S. Bureau of Labor Statistics, confirmed by B&V's corporate escalation tool. While escalation to current dollars is a reasonable adjustment, it does not affect the outcome of a cost effectiveness analysis because the cost effectiveness of other analyses used to establish the acceptable cost range should also be adjusted for escalation.

B&V's calculations do not consider the weakening of labor markets that has occurred since they set up their spreadsheets in 2007. According to B&V, in the pre-2004 period, its estimating department found that construction indirects were typically 50% to 60% of installation labor costs. In the post-2005 period, they reported construction indirects rose to a range of 90% to 120% of installation labor costs due to tightening in labor markets. However, in the 2010-revised cost estimate, Black & Veatch did not adjust the construction indirects to reflect the loosening of the labor market. The tightening of the labor markets has now reversed, skilled labor is underutilized, and per diem is not being paid at all, or only paid for a portion of the labor force.

"Real-World" SCR Capital Costs

Real-world, utility industry-generated evidence that PNM has overestimated its SCR costs can be found in a June 2009 article in "Power" magazine:[9] "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..." (or $184/kW in 2009 $).

"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."

[8] Table 1 of the PNM 2.11.11 submittal.

[9] 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/

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 $211/kW, converted to 2009 dollars.[10] Costs are escalated through using the 2009 CEPCI (because the final 2010 CEPCI is not yet available).

The second survey of 40 installations at 24 stations reported a cost range of $75 to $240/kW, converted to 2009 dollars.[11]

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.[12]

A fourth study, presented in a course at PowerGen 2005, reported an upper bound range of $178/kW to $201/kW, converted to 2009 dollars.[13]

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.[14]

Other recent estimates suggest that the SJGS SCR capital costs may be overestimated. Wisconsin Electric estimated the cost to retrofit SCR on Oak Creek Units 5-8 to be $175/kW[15] for a cold-side SCR. This cost was certified in July 2008 for construction by the Wisconsin Public Services Commission.[16] Wisconsin Power and Light estimated the cost to retrofit SCR on the 430-MW

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[10] 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 was converted to 2009 dollars ($106 - $211/kW) using the ratio of CEPCI in 2009 to 2002: 521.9/395.6.

[11] 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 2009 dollars ($75 - $240/kw) using the ratio of CEPCI for 2009 to 1999 (521.9/.390.6) for lower end of the range and 2009 to 2003 (521.9/401.7) for upper end of range, based on Figure 3.

[12] M. Marano, Estimating SCR Installation Costs, Power, January/February 2006. Ex. 5. The reported range of $100 - $221/kW was converted to 2009 dollars ($117 - $260/kW) using the ratio of CEPCI for 2009 to 2004: 521.9/444.2. http://findarticles.com/p/articles/mi_qa5392/is_200602/ai_n21409717/print?tag=artBody;col1

[13] 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 2009 dollars ($178 - $201/kW) using the ratio of CEPCI for 2009 to 2005 (521.9/468.2).

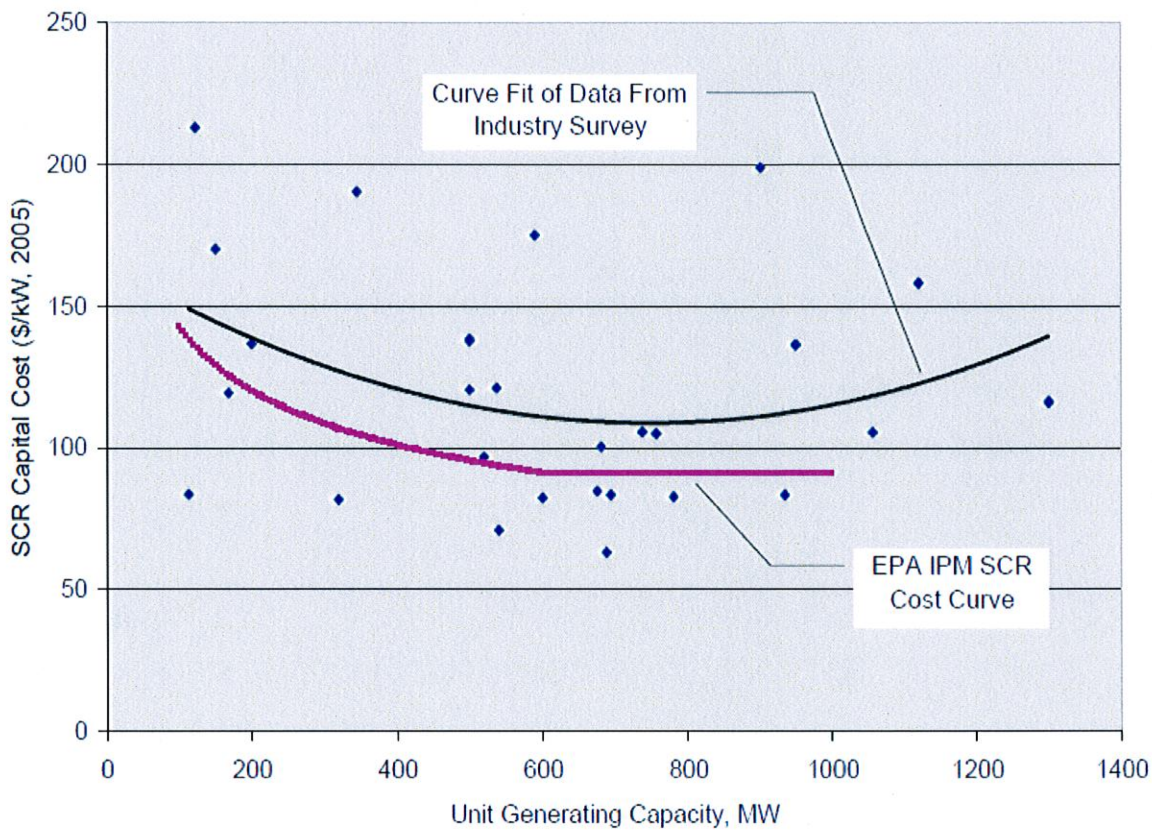
[14] J. Edward Cichanowicz, Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies, June 2007, pp. 28-29, Figure 7-1 (Ex. 1).

[15] Wisconsin Electric Power Company's Application to Install Wet Flue Gas Desulfurization and Selective Catalytic Reduction Facilities and Associated Equipment on Oak Creek Power Plant Units 5, 6, 7 & 8 for Control of Sulfur Dioxide and Nitrogen Oxide Emissions, Appendix C, Emission Reduction Study, Volume 1, Addendum August 20, 2007. Unit cost = ($190,500,000/1,135,000 kW) (521.9/499.6) = $175 kW.

[16] Certificate and Order, Application to Install Wet Flue Gas Desulfurization and Selective Catalytic Reduction Facilities and Associated Equipment on Oak Creek Power Plant Units 5, 6, 7 & 8 for Control of Sulfur Dioxide and Nitrogen Oxide Emissions, Case 6630-CE-299, July 10, 2008. Available here: http://www.we-energies.com/home/OCPP_approvalPSCWOrder.pdf.

Edgewater Unit 5 to be $324/kW in January 2008.[17] Similarly, American Electric Power (AEP) estimated that the average capital cost to install SCRs to remove 85-93% of the NOx from many of its units was $162/kW.[18]

EPA's Region 8 Office has compiled a graphic presentation of SCR capital costs—please see Appendix B for "SCR References"



The EPA data confirm that SCR capital costs typically range from $73 – $243/kW. In comparison, PNM's cost estimates for SJGS appear to be overestimated.

A graphic illustration of a "real-world" retrofit was presented by Burns & McDonnell at the 2010 Power Plant MegaSymposium and is provided in Appendix B in the "Boswell retrofit" files. Despite the limited space and other obstacles, the SCR installation cost $224/kW.[19] It should also be noted that the Boswell #3 retrofit was designed to meet 0.05 lb/mmBtu annual average and a

[17] Wisconsin Power & Light Co., Certificate of Authority Application, Edgewater Generating Station Unit 5 NOx Reduction Project, Project Description and Justification, November 2008, PSC Ref#: 105618, p. 11. The unit cost was calculated from the total project cost minus escalation divided by gross generating capacity or: ($153,944,000 - $14,695,000)/430 MW = $323.8/kW.

[18] AEP, 2008 Fact Book, 43rd Financial Conference, Phoenix, AZ, pdf 103. Available here: http://www.aep.com/investors/present/documents/2008EEI-Fact-Book.pdf.

[19] Minnesota Power's Environmental Improvement Plan submitted to the MN PUC 10/27/06, Docket #E015/M-06-1501. LNB+OFA+SCR TCI = $77 million in 2006 $ on 375 (gross) MW Unit #3 = ($77,000,000)/ (375,000) (521.9/499.6) = $224/kW.

0.07 lb/mmBtu 30-day rolling average. Burns & McDonnell reported that performance tests showed that, "Average NOx emissions at the outlet of the SCR reactor were 0.029 lb/mmBtu, which is below the design emission rate for the SCR system (0.05 lb/mmBtu)."

The overall range for these industry studies is \$50/kW to \$400/kW.[20] The upper end of this range is for highly complex retrofits with severe space constraints, such as Belews Creek, reported to cost \$383/kW,[21] or Cinergy's Gibson Units 2-4. Gibson, a highly complex, space-constrained retrofit in which the SCR was built 230 feet above the power station using the largest crane in the world,[22] cost \$236/kW in 2009 dollars.[23] PNM has presented no valid information to show why its cost estimates should exceed all available industry data.

PNM's SCR capital cost estimation methods are flawed.

<u>PNM has improperly rejected use of the OAQPS Control Cost Manual (Cost Manual) in favor of methods not allowed by EPA.</u>

The SCR cost estimates submitted by PNM are severely lacking in the types of specific information needed to give them credibility. According to B&V, PNM's consultant, "Capital cost estimates were developed for retrofit control technologies identified as technically feasible for the SJGS units. The capital cost estimates were based on the Coal Utility Environmental Cost (CUECost) estimates, cost data supplied by equipment vendors (budget estimates), and estimates from previous in-house design/build projects."

Both OAQPS and EPA Region 8 have advised against the use of the CUECost model, which was relied upon by B&V. Instead, the BART Guidelines recommend use of the Cost Manual:

> 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, 453/B-96-001). In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible. The Control Cost Manual addresses most control technologies in sufficient detail for a BART analysis. 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.

As detailed in EPA's analysis of the B&V cost estimates and discussed later, the "vendor quotations" cited by B&V as the basis for its SCR cost estimates for SJGS were taken from a project in Florida that is different from SJGS, thus giving the wrong idea or impression. The "estimates from previous in-house design/build projects" cited by B&V, as noted below, are simply factored estimates based upon Purchased Equipment Cost estimates.

[20] Exhibit 19 - J.E. Cichanowicz Overview of Information on Project Control Technology Costs – October 15, 2010

[21] Steve Blankinship, SCR = Supremely Complex Retrofit, Power Engineering, November 2002, Ex. 7. The unit cost: (\$325,000,000/1,120,000 kW) (521.9/395.6) = \$383/kW.
http://pepei.pennnet.com/display_article/162367/6/ARTCL/none/none/1/SCR-=-Supremely-Complex-Retrofit/

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

[23] 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) (521.9/395.6) = \$236/kW.
http://www.mcilvainecompany.com/sampleupdates/NoxMarketUpdateSample.htm

EPA's belief that the Control Cost Manual should be preferred over CUECost for developing cost analyses that are transparent and consistent across the nation and provide a common means for assessing costs is further supported by this 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.

Larry Sorrels, an economist at EPA's Office of Air Quality Planning and Standards (OAQPS) wrote the following to Aaron Worstell of EPA Region 8 on September 8, 2010:

> the way that CUECost estimates total capital cost and O&M cost is different from the Control Cost Manual. In particular, the total capital cost estimate from CUECost is the same as the total capital requirement (TCR), an estimate that is part of the levelized cost methodology devised by EPRI. A TCR estimate includes Allowance for Funds Used During Construction (AFUDC), an estimate that is not included in the total capital cost according to the Control Cost Manual method. Also, O&M costs are calculated differently, with fixed and variable components being included in the O&M costs, a distinction at odds with the Cost Manual method.

We note that, in New Mexico Environment Department's (NMED) December 21, 2007, letter to PNM, the NMED requested that the cost estimate for SCR be performed using the OAQPS Cost Manual. In its March 29, 2008, response, "Discussion of OAQPS Cost Manual Method for AQCS Estimation," 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." 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.

PNM discussed the need to escalate costs estimated using the Cost Manual, and we agree. We have been advised by OAQPS[24] 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,[25] 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 PNM concluded that "the Cost Manual is geared more towards developing costs for new units than retrofitting controls on existing units," because the Cost Manual contains an adjustment for retrofit situations.

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

[24] 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."

[25] We suggest that 2009 be used until the 2010 CEPCI is available.

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.

Cost Manual 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.

Cost Manual 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 has included costs not allowed by EPA, and overestimated other costs.

PNM is including a separate $22 million 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 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.

PNM has also included a $78 million cost for Allowance for Funds During Construction (AFUDC) for SCR at SJGS that may not be allowable because if the AFUDC cost is not "already included in the base case as per a utility commission decision." Mr. Sorrels also provided[26] insight on the AFUDC:

> I agree with including AFUDC in a capital cost estimate if this is already included in the base case as per a utility commission decision. Otherwise, I do not agree with its inclusion.

The estimates provided by PNM are its consultant's rough estimates based upon developing a Total Purchased Equipment Cost (PEC) or Direct Capital Cost (DCC) and applying its standardized estimation factors to the PEC/DCC. As a result, PNM has generated capital cost estimates that exceed real-world industry data and contain items that are inflated and/or not allowed by EPA.

The $423 - $568/kW (estimated by PNM in 2010 $) TCI provided by PNM is indicative of the overestimates throughout the analysis presented by PNM. These deviations from standard practice project the cost to control NOx using SCR at SJGS to be higher than at other similar sources. However, these apparently higher costs appear to be due to the PNM costing method, not to any unique circumstances at the units that may make the retrofit of SCR unusually costly.

The Guidelines suggest that documentation be provided for "any unusual circumstances that exist for the source that would lead to cost-effectiveness estimates that would exceed that for recent retrofits." PNM has provided no documentation regarding unique circumstances related to the BART determinations. All of PNM's TCI estimates, when reduced to $/kW, exceed the highest actual costs reported by the industry.

Some additional examples of the PNM capital cost overestimates are taken from the B&V cost analysis and are presented below.

The B&V estimates are higher than other recent estimates, including its own. The cost for most of these items was scaled from the Saint Johns River Power Park (SJRPP) project that B&V had completed the year before they did the initial SJGS cost estimate. Costs for some items were also scaled from other unidentified projects. The unit capital cost for the SJRPP SCR that B&V designed and used to scale costs to the SJGS SCR is $187/kW in 2010 dollars. This is a factor of two to three less than B&V estimated for SJGS by extrapolating from SJRPP. As explained elsewhere, the SJRPP SCR would be more costly than an SCR at SJGS as SJRPP burns a very challenging coke/coal blend.

The SCR retrofit for SJRPP involved significant challenges due to the range of fuels and direct bunkering operations for purposes of blending fuels, which is not practiced at SJGS. The SJRPP fuels include a blend of 30% petroleum coke and 70% coal, with coke fired for up to 6,000 hours. The coals included a low calcium eastern domestic coal and a high-silica (erosive) Colombian coal. These three fuels coupled with direct-bunkering resulted in designs that do not extrapolate to SJGS and, in fact, overestimate SJGS costs when extrapolated from SJRPP. The six-tenth rule that B&V used in these extrapolations only applies when the underlying design is identical.

[26] 7/21/10 e-mail to Don Shepherd

Ductwork and ammonia injection grid costs for SJGS are overestimated. Petroleum coke firing results in higher flue gas temperatures than coal firing. This required material selection based on a design temperature of 824 °F and the use of more expensive materials of construction for SJRPP: ASTM A588 for ductwork and ASTM A335 P11 for the ammonia injection grid. The flue gas temperature for the SJGS units ranges from 707 °F at Unit 1 to 720 °F at Units 3 and 4.[17] As discussed below, more expensive ductwork materials were used for the SJRPP, based on higher anticipated flue gas temperatures than are present at the SJGS. Thus cheaper materials could be used for the ammonia injection grid and the ductwork.

Petroleum coke firing results in high levels of unburned carbon, which increases the risk of fires in the ductwork. To avoid fly ash deposition on the ductwork floor, the SJRPP ductwork was designed with a high average flue gas velocity, which increases the cost of the ductwork, reactor housing, and catalyst compared to the cost of comparables at SJGS. As ductwork fires are not an issue at SJGS, an SCR could be designed with a lower duct velocity, thus decreasing the cost of most components of the SCR.

Petroleum coke also contains high levels of sulfur, up to 6.94%, compared to 0.77% sulfur in the coal burned at SJGS. The high fuel sulfur at SJRPP results in corrosive flue gases that form sulfuric acid mist and ammonium bisulfate in the pollution control train, thus requiring more expensive materials of construction.

The B&V BART cost for the reactor box, breeching and ductwork was based on a preliminary quote of $5,613,000 per unit for SJRPP, which was adjusted to account for differences in the size of the SJGS units. The final contract price was $4,877,223 per unit. Thus, the B&V cost analysis was adjusted to use the final cost. The cost was adjusted to 2007 dollars using an escalation rate of 1.03. This estimate was further escalated to 2010 dollars per the B&V 10/22/10 cost analysis. Further, more expensive materials of construction were used for SJRPP as maximum flue gas temperatures were higher (>750 °F) than expected at SJGS (<700 °F).

The expansion joint cost was scaled from the total cost for both SJRPP units ($360,430) instead of one unit, using the ratio of volumetric gas flow rate in acfm and adjusted to 2007, using an escalation rate of 1.03. This estimate was further escalated to 2010 dollars per the B&V 10/22/10 cost analysis. Further, the vendor quoted price includes freight, which is double counted elsewhere in the B&V cost analysis. Finally, the joints are designed for an operating temperature of 800 °F with excursions to 900 °F. This is far higher than expected at SJGS, which could use less expensive materials.

The sonic horn cost was estimated from a preliminary quote for SJRPP, adjusted to 2007, using an escalation rate of 1.03 and further escalated to 2010 dollars per the B&V 10/22/10 cost analysis. However, the final contract award was lower. Further, the final contract award included freight to the site, which is double counted elsewhere in the B&V cost spreadsheet.

The elevator cost was estimated from a preliminary quote for SJRPP, adjusted to 2007, using an escalation rate of 1.03 and further escalated to 2010 dollars per the B&V 10/22/10 cost analysis. However, the final contract award was lower. Further, the final contract award includes installation, which is broken out separately on the bid form, as well as freight and taxes.

Installation, freight, and taxes are calculated elsewhere in the B&V cost spreadsheet and thus are double-counted.

The structural steel cost was estimated from a budgetary quote for SJRPP, adjusted to 2007, using an escalation rate of 1.03, and a "complexity factor." This estimate was further escalated to 2010 dollars per the B&V 10/22/10 cost analysis. The complexity factor is a contingency for site congestion that has been double counted in a contingency figured as 20% total direct costs, as discussed elsewhere. Further, inspection of Google Earth images of SJGS and SJRPP suggests that SJGS is not more congested than SJRPP. Finally, the B&V structural steel cost includes freight to the jobsite, which is included elsewhere. Even with these adjustments, structural steel costs are overestimated, as the contract award amount used to make these extrapolations included "all associated engineering and design costs, procurement, fabrication, overtime, overhead, profit mark-up and shipping to the jobsite." Further, the structural steel was to be delivered painted; these costs are double-counted elsewhere.

The SCR bypass cost was estimated from a budgetary quote for SJRPP, adjusted to 2007, using an escalation rate of 1.03, and a "complexity factor." This estimate was further escalated to 2010 dollars per the B&V 10/22/10 cost analysis. This results in a cost of $10 million per unit for an SCR bypass to route flue gas around the catalyst during startup. This is claimed to be required to prevent catalyst fouling when firing oil during startup. However, fouling would only occur if the oil is not burned and thus coats the catalyst. This could only occur due to poor combustion. Oil is very efficiently burned in modern Low-NO_x Burners with oil igniters, such as those on the SJGS units, which were installed between 2007 and 2010. If these burners are properly maintained and operated, fouling during startup will not occur.

Catalyst can be designed to avoid oil startup issues. The Mirant Unit 1 & 2 SCR system at the Morgantown Station is designed to remove 92.5% of the NO_x, to an outlet of 0.045 lb/mmBtu, for year round operation with no SCR bypass during startup when the plant fired fuel oil and for No. 6 oil during cofiring. Similarly, Duke Energy's Belews Creek Steam Station, for example, has operated two 1200-MW bituminous coal- fired boilers with SCR since 2004, with oil startup and no catalyst bypass. Further, there are oil-fired boilers and turbines equipped with SCR that operate without bypasses.

The NO_x Monitoring cost was estimated from a preliminary quote for SJRPP, adjusted to 2007, using an escalation rate of 1.03 and further escalated to 2010 dollars per the B&V 10/22/10 cost analysis. However, the final contract award was lower. The final contract award included freight to the site, on-site training for each of two units, and a 3-year maintenance contract. Freight and maintenance are double-counted as they are included elsewhere. Further, only a single training session is required for all four SJGS units, not a separate training session for each unit, as estimated by B&V.

In the October 22, 2010, revision to its cost analysis, B&V added a new cost item, "auxiliary electric system requirements," amounting to $6,400,000 for each of Units 1 and 2 and $8,350,000 for each of Units 3 and 4. These additions are based on "minimum" load changes due to the SCR totaling 26,254 kW. These increased loads are met by replacing existing fans with larger fans and include flow margins of 15% to 20% and pressure margins of 35% to 45%.

The auxiliary power upgrade is required due to the cumulative effect of the Consent Decree projects and the SCR and benefits the entire fan auxiliary system. The SCR project was initially evaluated at the same time that the Consent Decree projects were being designed. B&V states: "In the initial 2007 estimate, PNM expected the existing auxiliary power to be sufficient. However, now that the consent decree AQC equipment has been installed, B&V has determined that the current auxiliary power system is not sufficient to power the additional loads that would result from adding SCR and associated equipment." Further, the auxiliary power upgrades cumulatively serve the increase in auxiliary power. The modifications, for example, include new transformers, switchgear, and motor control centers that will serve the entire fan auxiliary loads of both the Consent Decree projects and the SCR. Thus, these costs should be prorated, rather than partitioned to the last project built.

The instrumentation and control system cost was estimated from a preliminary quote for SJRPP, adjusted to 2007 using an escalation rate of 1.03 and further escalated to 2010 dollars per the Black & Veatch 10/22/10 cost analysis. However, the final contract awards were higher. They consist of the sum of bids from two separate contractors. In each case, the quotes include freight to the site and installation, both of which are double counted elsewhere.

The 2007 cost estimate included $1,071,000 to modify each of the air preheaters at Units 1 and 2 and $8,685,000 to modify each of the air preheaters at Units 3 and 4. In response to an EPA comment, B&V modified the Units 3 and 4 estimate to eliminate double counting, revising the cost for Units 3 and 4 to $5,090,000 each. These figures were further escalated to 2010 dollars in the B&V 10/22/10 cost analysis. These estimates were variously claimed to be based on "the experience of a confidential client" and a "quote for SJGS" and "scaled from another project." B&V declined to share the basis for these costs with EPA.

The air preheater modifications are not required for a properly designed SCR on a boiler that burns low sulfur coal. B&V asserts the upgrades are required to make the air preheaters resistant to ammonium bisulfate corrosion and plugging. Air preheater modifications are required for units that burn high sulfur coal. However, SJGS burns a low sulfur coal containing only 0.77% sulfur. These lower sulfur coals generate very little sulfur trioxide and thus little ammonium bisulfate corrosion and plugging. Air heater plugging is not an issue for these coals if the SCR is designed with a low SO_2 to SO_3 catalyst and an ammonia slip of 2 ppm. These are both proposed for the SJGS SCR. Thus, air preheater modifications are not required for the SJGS SCR. (See discussion of this issue by Sargent & Lundy for a similar facility burning a similar coal in a BART analysis for the Navajo Generating Station.)

The revised B&V costs include $14.3 million at each of Units 1 and 2 and $18.7 million at each of Units 3 and 4 for balanced draft conversions. These figures were further escalated to 2010 dollars in the Black & Veatch 10/22/10 cost analysis. The majority of these costs, 70%+, is due to stiffening of the boiler, air heater, electrostatic precipitator, and fabric filter to comply with code. The balance of the costs are for induced draft fans to support the increased draft from the SCR and new motors for existing forced draft fans. Although increased draft is needed to support an SCR, which would be delivered by the induced draft fans, a balanced draft conversion with the proposed stiffening is not part of an SCR project. As balanced draft conversion is not required for an SCR, under this interpretation, stiffening would not be required.

The B&V cost analyses assume a 12-week outage would be required to complete the balanced draft conversion. The SCR would be installed during the routine seven-week outage. The remaining five weeks is required for the stiffening. This charge is not allowed by the Cost Manual. Further, it is unwarranted as the required stiffening work can be completed over multiple routine outages. With planning, no lost generation would be incurred.

The contingencies included in the B&V cost estimates are double-counted. There are three separate contingencies imbedded in the analysis. First, the cost of structural steel and the SCR bypass were increased by a factor of 1.2 at Units 1 and 4 and by a factor of 1.5 at Units 2 and 3 to address the "significantly more challenging site at SJGS compared to SJRPP." Second, a separate contingency of $2,000,000 was included for each unit for "site unknowns, such as underground utilities" and $500,000 for each unit for "general site building requirements". Third, a contingency of 20% of total direct costs (thus building contingencies on top of contingencies) was included for each unit under indirect costs. This latter contingency was based on the CUECost model, which has not been approved for BART cost analyses. The sum of these contingencies amounts to approximately $18 million for Unit 1, $22 million for Unit 2, $27 million for Unit 3, and $23 million for Unit 4, or about two thirds of the purchased equipment cost. The Cost Manual stipulates a 5% process contingency for indirect installation costs, figured as 5% of total direct costs, and a 15% project contingency, figured as 15% of total direct and total indirect installation costs.

The factors used for SJGS are unsupported in the record, even though New Mexico specifically requested support. The factors are demonstrably high. An SCR is a metal frame stuffed with blocks of catalyst. It has no moving parts. Painting, for example, is minimal as most items arrive at the site primed; structural steel arrives at the site painted. In fact, Black & Veatch zeroed out both painting and insulation in its calculation of construction indirects, but failed to carry this over to direct installation costs. Foundation and supports, estimated as 30% of purchased equipment cost, are two to three times higher than upper bound costs reported by others for similar sized units ($8/MW compared with $18/MW to $29/MW for SJGS).

NPS' Application of the EPA Control Cost Manual

Based upon industry and EPA estimates, we assumed a TCI of $200/kW for the two smaller EGUs and $180/kW for the two larger EGUs.

Annual SCR Costs and Cost-effectiveness expressed in $/ton of NO_X Removed.

The Direct Annual Cost (DAC) component of the process is also important because it represents a significant portion of the Total Annual Cost. The methods presented by the Cost Manual for estimating DAC appear to be straightforward and should accurately represent annual costs with no need for adjustment.

<u>PNM has overestimated annual operating costs.</u>

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 Appendix C of PNM's June 6, 2007, BART analysis,[27] and it has not been updated to reflect PNM's subsequent higher estimates of TCI. In addition to the higher-than-recommended ratios used by PNM to estimate its TCI, the estimates generated by PNM for its annual operating costs are also higher than corresponding estimates generated by the Cost Manual.[28]

- Operating labor was estimated at $125,000/yr for each unit, based on one full time equivalent (FTE). However, the Cost Manual explains that the SCR reactor is a stationary device with no moving parts and uses only a few pieces of rotating equipment (e.g., pumps, motors). Thus, existing plant staff can operate the SCR from the existing control room. The Cost Manual explains: "In general, operation of an SCR system does not require any additional operating or supervisory labor." Maintenance labor and materials were estimated by B&V as 3% of the total direct costs. However, the Cost Manual reports that maintenance labor and material should be estimated as 1.5% of total capital investment.
- PNM's $700/ton reagent cost is much higher than any we have seen elsewhere.
- B&V assumed a total auxiliary power demand of 16,297 kW for the four units, which amounts to 0.9% of the total gross generating capacity of the station. An SCR typically uses about 0.3% of a plant's electric output, which would be about 5,400 kW or three times less than assumed in the cost analysis. Second, the unit cost of electricity used by B&V, $0.06095/kWh, is higher than the default cost used in cost effectiveness analyses, $0.05/kWh. Auxiliary power is the power required to run the plant, or power not sold. Cost effectiveness analyses are based on the cost to the owner to generate electricity, or the busbar cost, not market retail rates. The B&V estimate is based on the average forecasted cost of replacement power for 2007 to 2012. Other recent BART analyses for similar facilities have used auxiliary power costs that range from $0.03/kWh to $0.05/kWh.
- PNM has assumed a two-year catalyst life instead of the typical three years; this inflated the Annual Catalyst Costs. Catalyst replacement cost did not consider catalyst regeneration, which has become an alternative to purchasing new catalyst since the Cost Manual was last updated. The cost of purchasing new catalyst was assumed to be $6,500/m^3, while the cost to regenerate is about 60% of this price. Setting aside regeneration, the catalyst cost used by Black & Veatch, $6,500/m^3, is higher than the cost recently quoted by Hitachi for a nearly identical coal, $5,500/m^3 to $6,000/m^3.The catalyst volume was scaled from another Black & Veatch project, Harding Street Unit 7. The scaling took into account the difference in flow rates but not the differences in NO_x reduction. For the 0.07-lb/MmBtu cases, SJGS catalyst volume should be based on reducing NO_x from 0.3 lb/MmBtu to 0.07 lb/MmBtu or by 0.23 lb/MmBtu. For the 0.05-lb/MmBtu cases, catalyst volume should be based on reducing NO_x from 0.3 lb/MmBtu to 0.05 lb/MmBtu or by 0.25 lb/MmBtu. The Harding catalyst volume was based on reducing NO_x from 0.34 lb/MmBtu to 0.044 lb/MmBtu or by 0.3 lb/MmBtu. When the difference in NO_x reduction is factored in, catalyst volume, and hence replacement cost,

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[27] PNM's March 2008 "Discussion of OAQPS Cost Manual Method for AQCS Estimation," Appendix B "Details of Cost Calculation Using OAQPS Cost Manual" was presented in response to NMED's request for an analysis following the Cost manual.

[28] We do not understand why the Indirect Annual Costs calculated by PNM remained constant from 2008 to 2010 in spite of the increased TCI estimated by PNM.

drop by about 15% for the 0.07-lb/MmBtu cases and by about 10% for the 0.05-lb/MmBtu cases.

- PNM used a 7.41% interest rate instead of the 7% rate recommended by EPA. Combined with the inflated TCI, this further inflated the Indirect Annual Costs.
- 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. This lower removal estimate inflated PNM's cost/ton estimates.

These issues result in PNM's Total Annual Cost and Cost/ton estimates that go well beyond what is usual, regular, or customary.

An excellent example of a SCR retrofit cost analysis was prepared for the Navajo Generating Station (NGS) and submitted to EPA Region 9.[29] The NGS analysis contains the type of vendor estimates and detailed engineering analyses that are recommended by the BART Guidelines and that are necessary to arrive at a reasonable and informed estimate of site-specific costs. In the absence of such a comprehensive analysis, the BART Guidelines recommend use of the EPA Control Cost Manual.

<u>NPS estimate of annual operating costs.</u>

We also performed annual cost estimates using the Cost Manual for SJGS and used catalyst[30] 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. Using our estimates of Total Capital Investment coupled with a direct application of the Cost Manual methods to estimate annual costs, we estimated the costs shown in the table below:

Annual Costs* & Benefits	Unit #1		Unit #2		Unit #3		Unit #4	
	NPS	PNM	NPS	PNM	NPS	PNM	NPS	PNM
Annual Maintenance Cost =	$ 1,080,000	$ 2,369,000	$ 1,050,000	$ 2,532,000	$ 1,468,800	$ 3,166,000	$ 1,468,800	$ 2,961,000
Annual Reagent Cost =	$ 638,555	$ 911,000	$ 630,810	$ 906,000	$ 966,343	$ 1,415,000	$ 997,237	$ 1,388,000
Annual Electricity Cost =	$ 575,558	$ 1,496,000	$ 568,577	$ 1,492,000	$ 1,005,010	$ 2,194,000	$ 898,854	$ 2,215,000
Annual Catalyst Cost =	$ 385,341	$ 426,000	$ 382,027	$ 426,000	$ 458,338	$ 538,000	$ 610,813	$ 541,000
Direct Annual Cost =	$ 2,679,454	$ 5,252,000	$ 2,631,414	$ 5,406,000	$ 3,898,491	$ 7,363,000	$ 3,975,704	$ 7,155,000
Indirect Annual Cost =	$ 6,796,291	$ 15,194,802	$ 6,607,505	$ 15,194,802	$ 9,242,955	$ 15,194,802	$ 9,242,955	$ 15,194,802
Total Annual Cost =	$ 9,475,745	$ 20,525,000	$ 9,238,919	$ 21,891,000	$ 13,141,446	$ 29,870,802	$ 13,218,659	$ 26,592,000
NOx Removed =	3,459	3,174	3,417	3,158	5,235	4,931	5,402	4,837
SCR Cost effectiveness =	$ 2,739	$ 6,466	$ 2,704	$ 6,932	$ 2,510	$ 5,752	$ 2,447	$ 5,497

*All costs are in 2010 $ except NPS' "Annual Maintenance Cost" and "Indirect Annual Costs" which are in 2009 $ (which also partially affect the "Total Annual Cost").

In addition to the PNM overestimates noted above, some additional differences highlighted in the table are:

[29] http://en3pro.com/2011/01/30/cost_estimate_report/

[30] 2010 vendor quotes for low-oxidation catalyst ranged from $4,895 to $6,250 per cubic meter.

- PNM's power costs are much higher than the Cost Manual estimate.
- 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.
- The Total Capital Investment would be approximately $392 million.
- The Incremental Annual Cost for adding SCR to remove over 17,000 tons/yr more NO_X would be $45 million or less than $2,600/ton.

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

Because the modeling analysis conducted by EPA is superior to that conducted by PNM, we are commenting only upon how the results of the EPA analyses can be interpreted in the context of the effectiveness of SCR at SJGS.

EPA modeled a revised baseline scenario to incorporate the proposed lower SO2 emission rate of 0.15 lb/mmBtu rather than the 0.18 lb/mmBtu included in the original post-consent decree baseline modeled by NMED. The purpose of this was to separate any visibility benefit from lowering the SO2 emission rate from the benefit received from the operation of the SCR.

Modeling Results--Visibility Improvement from Operation of SCR
EPA: "Modeled impacts on the Class I areas of SJGS are shown in Table 6-6. The table shows the maximum of the 98th percentile daily delta deciview impacts from the three modeled years using the default background ammonia concentration of 1 ppb and Method 8 to calculate visibility. ...Visibility improvement due to installation of SCR is significant, including a 3.11 dv improvement at Canyonlands and 2.88 dv at Mesa Verde. Total deciview improvement at all Class I areas within 300km of the facility is 21.69 dv, a decrease in visibility impairment of 65% from the revised baseline..."

EPA Table 6-6. EPA Modeling Results – Impacts of SJGS on Visibility (maximum of 98th Percentile of daily maximum dv of 2001, 2002, and 2003) at Sixteen Class I Areas (1ppb background ammonia concentration, Method 8)

Class I Area	Distance to SJGS (km)	Visibility Impact (dv) after applying: Revised Baseline	Visibility Impact (dv) after applying: SCR	SCR visibility improvement over revised baseline (dv)
Arches	222	3.50	1.12	2.38
Bandelier Wilderness	210	1.39	0.48	0.91
Black Canyon of the Gunnison Wilderness	203	1.41	0.42	0.99
Canyonlands	170	4.64	1.53	3.11
Capitol Reef	232	2.38	0.82	1.56
La Garita Wilderness	169	1.93	0.57	1.36
Grand Canyon	285	0.93	0.33	0.60
Great Sand Dunes National Monument	269	1.53	0.49	1.04
Mesa Verde	40	5.15	2.27	2.88
Pecos Wilderness	248	1.27	0.47	0.80
Petrified Forest	213	0.52	0.21	0.31
San Pedro Parks Wilderness	155	2.20	0.74	1.46
Maroon Bells Snowmass Wilderness	271	0.70	0.28	0.42
West Elk Wilderness	216	1.59	0.45	1.14
Weminuche Wilderness	98	2.92	0.87	2.05
Wheeler Peak Wilderness	258	1.12	0.44	0.68
Total Delta dv		33.18	11.48	21.69

NPS: Modeling results for the addition of SCR indicate that this option would reduce cumulative impacts by 21.69 dv with a 2.88 dv improvement at Mesa Verde NP (40 km away), with an even greater improvement predicted at Canyonlands NP (170 km away). We have observed in our analysis of impacts of the Navajo Generating Station (NGS) upon Grand Canyon National Park 20 km away that time (and, therefore, distance) is required for transformation of NO_X to visibility-impairing particulates. When we modeled impacts further into the Grand Canyon from NGS, we found that the benefits of reducing NO_X increased with distance, up to a point. The same effect may be occurring with SJGS, and modeling of more-distant receptors in Mesa Verde NP may yield even greater improvements.

Visibility Improvement Metrics

We support EPA in reporting the cumulative visibility impacts of SJGS and the benefits of SCR at the 16 Class I areas on the Colorado Plateau (EPA Table 6.7). We continue to believe that it is appropriate to consider both the degree of visibility improvement in a given Class I area as well as the cumulative effects of improving visibility across all of the Class I areas affected. It simply does not make sense to use the same metric to evaluate the effects of reducing emissions from a

BART source that impacts only one Class I area as for a BART source that impacts multiple Class I areas.

The BART Guidelines represent an attempt to create a workable approach to estimating visibility impairment. As such, they require several assumptions, simplifications, and shortcuts about when visibility is impaired in a Class I area, and how much impairment is occurring. The Guidelines do not attempt to address the geographic extent of the impairment, but assume that all Class I areas are created equal, and that there is no difference between widespread impacts in a large Class I area and isolated impacts in a small Class I area. To address the problem of geographic extent, we have been looking at the cumulative impacts of a source on all Class I areas affected, as well as the cumulative benefits from reducing emissions. While there are certainly more sophisticated approaches to this problem, we believe that this is the most practical, especially when considering the modeling techniques and information available. For example, we understand that the Oregon Department of Environmental Quality used a similar approach in its analyses when it evaluated the benefits of various control strategies on all 14 of the Class I areas within 300 km of the Boardman power plant. Cumulative benefits have been a factor in the BART determinations by NM, OR, and WY, as well as EPA in its proposals for the Navajo Generating Station and the Four Corners Power Plant. And, EPA, in its analysis supporting its determination that CAIR is better-than-BART simply summed dv impacts across many Class I areas of varying sizes in order to generate average visibility impact estimates.

NOx BART Determination

Cost-Effectiveness Metrics

In addition to the $/ton metric, we recommend that EPA evaluate the visibility metric $/deciview (dv) as an additional tool to report the benefits of emissions controls. BART is not necessarily the most cost-effective solution. Instead, it represents a broad consideration of technical, economic, energy, and environmental (including visibility improvement) factors. For example, Oregon DEQ has established a cost/ton threshold of $7,300 based upon the premise that improving visibility in multiple Class I areas warrants a higher cost/ton than where only one Class I area is affected. In their BART proposal for SJGS, New Mexico used a range from $5,946/ton to $7,398/ton. Colorado uses $5,000/ton, New York uses $5,500/ton, and Wisconsin is using $7,000 - $10,000/ton as its BART threshold.[31] EPA has proposed SCR at the Four Corners Power Plant at $2,600 - $2,900/ton, and at SJGS at $1,600-1,900/ton.

One of the options suggested by the BART Guidelines to evaluate cost-effectiveness is cost/deciview. We believe that visibility improvement must be a critical factor in any program designed to improve visibility. Compared to the typical control cost analysis in which estimates fall into the range of $2,000 - $10,000 per ton of pollutant removed, spending millions of dollars per deciview (dv) to improve visibility may appear extraordinarily expensive. However, our compilation[32] of BART analyses across the U.S. reveals that the average cost per dv proposed by

[31] "The Department used cost-per-ton reduced as the primary metric for determining the BART level of control. The upper limit for this metric was $7,000 to $10,000 per ton, which reflects historical low-end costs for controls required under BACT." BEST AVAILABLE RETROFIT TECHNOLOGY AT NON-EGU FACILITIES April 19, 2010, WISCONSIN DEPARTMENT OF NATURAL RESOURCES

[32] http://www.wrapair.org/forums/ssjf/bart.html

either a state or a BART source is $14 - $18 million,[33] with a maximum of $51 million per dv proposed by South Dakota at the Big Stone power plant. (For example, we note that OR DEQ has explicitly chosen $10 million/dv as a cost criterion, which is somewhat below the national average.)

When we combine our cost estimates for SCR with the visibility improvement estimated by EPA, we find that SCR costing $45 million/yr would yield a 3.11 dv improvement at Canyonlands NP for a cost-effectiveness there of $14.5 million/dv and a cumulative improvement of 21.69 dv for a cumulative cost-effectiveness of $2.1 million/dv. Because both the individual and the cumulative cost-effectiveness of SCR are within (or below) the range of costs accepted by other states (and EPA), SCR is clearly cost-effective at SJGS.

Conclusions & Recommendations

We have shown that PNM has underestimated the ability of SCR to reduce emissions, and presented real-world emission data showing examples of coal-fired EGU retrofits meeting 0.05 lb/mmBtu (or lower) on an annual basis. We have also shown that Black & Veatch, the consultant that prepared the SJGS estimates, assumed that SCR could achieve 0.05 lb/mmBtu (annual average) when evaluating retrofitting of SCR at the Craig power plant. (And, Salt River Project has used a 0.05 lb/mmBtu annual average in its SCR retrofit analysis for the Navajo Generating Station.) While it is easy to find coal-fired SCR retrofits that are emitting at higher rates, we believe that we should be basing decisions upon what the current state-of-the-art can do,[34] and SCR can achieve 0.05 lb/mmBtu or lower on an annual average at SJGS.

We have also provided evidence indicating that PNM has overestimated SCR costs. The Black & Veatch approach used by PNM is neither transparent nor does it follow the methods described in the EPA Control Cost Manual. Instead, the B&V approach includes costs which are not appropriate, and the results are consistently higher than real-world industry data would suggest are appropriate for SJGS (or any other power plant).

We commend EPA 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 lower NO_X emission rates on an annual basis than used by PNM in its analyses, which supports EPA'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 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 EPA's concern that PNM has overestimated the cost of installing and operating SCR.

[33] For example, PacifiCorp has stated in its BART analysis for its Bridger Unit #2 that "The incremental cost effectiveness for Scenario 1 compared with the baseline for the Bridger WA, for example, is reasonable at $580,000 per day and $18.5 million per deciview."

[34] In its 10/26/10 letter to CDPHE, EPA advised that "many boilers retrofitted with SCR are achieving an emission rate of 0.03 – 0.06 lb/mmBtu" and that the state should take current emission rates into consideration.

We estimate that addition of SCR to SJGS Units #1 - #4 represents BART because it would result in cost-effectiveness values that fall within the $14 million - $20 million **average** cost/deciview proposed as BART by other sources and states.

We conclude that SCR at 0.05 lb/mmBtu (30-day rolling average) represents BART for SJGS.