United States Department of the Interior

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TAKE PRIDE IN AMERICA

IN REPLY REFER TO:

N3615 (2350)

May 25, 2012

Carl Daly, Director
Air Program
U. S. Environmental Protection Agency, Region 8
Mailcode 8P-AR
1595 Wynkoop Street
Denver, Colorado 80202-1129

EPA Docket ID: EPA-R08-OAR-2011-0770

Dear ~~Mr. Daly~~: Carl

The National Park Service has reviewed the Environmental Protection Agency (EPA)'s "Approval and Promulgation of Implementation Plans; State of Colorado; Regional Haze State Implementation Plan." We commented extensively on Colorado Department of Public Health and Environment (CDPHE)'s draft proposals. Overall, we commend CDPHE on the quality of the final Colorado plan. The Colorado Clean Air Clean Jobs Act will accomplish considerable progress in reducing emissions that impair visibility in our Class I areas. Additional emissions reductions will be implemented under the Best Available Retrofit Technology (BART) requirements and the demonstration of reasonable progress toward the visibility improvement goals.

We have two remaining concerns with the Colorado Regional Haze Implementation Plan and EPA's proposed approval of the plan. We believe that consistency is important to the success of a national program designed to address regional issues. Consistent with EPA findings for other similar facilities, therefore, we believe that Selective Catalytic Reduction technology is cost-effective and should be implemented as BART for Tri-State's Craig Generating Station Units 1 and 2 and as reasonable progress for Craig Unit 3.

Our enclosed comments demonstrate that the SCR control costs developed by Tri State and its consultants and used by CDPHE and EPA in their reviews significantly exceed the utility industry data for actual costs of implementation. Using industry data for facilities similar to Craig and the same cost methods as used by EPA Region 8 for the proposed Federal Implementation Plan for Montana, we find the costs of SCR to be between

$1,962 and $2,385 per ton for Craig Units 1-3. This is well below the threshold cost of $5,000/ton that CDPHE determined to be reasonable for SCR installation.

CDPHE presented visibility benefits of SCR for the single Class I area with the maximum visibility impact. NPS conducted its own analysis using CDPHE's modeling files with our revisions (as described in the attachment) to project visibility benefits at eight Class I areas impacted by Craig. Our analyses demonstrate that the visibility benefits of installing SCR for each Craig unit exceed CDPHE's threshold visibility benefit (0.5 deciview for the Class I area with maximum impact) at five Class I areas. The cumulative visibility benefit at eight Class I areas is 10 dv for SCR on all three Craig units (4.5 dv for SCR on each Craig unit.) These benefits are greater than those resulting from other Colorado BART actions. SCR is justified for Craig Units 1, 2, and 3.

We also have enclosed comments on the Rio Grande Cement Corporation facility south of Pueblo, which we believe should have been considered under Colorado's reasonable progress analysis. CDPHE required two similar cement plants in Colorado, Cemex and Holcim, to achieve a NO_x control efficiency of 45% using Selective Non-Catalytic Reduction. Rio Grande Cement has installed SNCR but is not required by permit to operate these controls. We recommend that Rio Grande Cement be required to meet 45% control efficiency using the existing SNCR.

We appreciate the opportunity to work closely with EPA Region 8 and CDPHE to improve visibility in our Class I areas. For further information regarding our comments, please contact Don Shepherd at (303) 969-2075.

Sincerely,

Susan Johnson
Chief, Policy, Planning and Permit Review Branch

Enclosures

cc:
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NPS Comments on GCC Rio Grande, Inc. for Colorado Regional Haze Plan
May 25, 2012

GCC Rio Grande, Inc. (GCC) currently owns and operates a Portland cement plant, located approximately 6 miles south of the city of Pueblo, Colorado and 86 km from Great Sand Dunes National Park and Preserve, a Class I area administered by the National Park Service (NPS). CDPHE granted the Initial Approval permit to Rio Grande Cement Corporation on September 25, 2000. GCC is not subject to BART, but should be subject to analysis as part of Colorado's Reasonable Progress (RP) requirement. Current (Mod 4) and proposed[1] (Mod 5) permit limits are shown below:

APCD TABLE 1 – Comparison of Plant Annual Total Emissions Limits (current and proposed in tons per year)

	PM	PM10 Total	NOx	SO2	VOC	CO	CO2 equivalent
Requested (Mod 5)	141	417.6	1,140.30	953.6	99	1,110.10	1,126,694
Current (Mod 4)	159.7	164.1	1,105.00	943.58	39	1,011.10	924,000

According to GCC, the Pueblo plant began producing cement on April 12, 2008. After this initial startup, the plant experienced a number of significant problems that impacted its operations, including kiln and finish mill malfunctions and repairs (additional details are provided in the application). CDPHE recognized several force majeure events and granted two compliance demonstration extensions in August and November 2008. GCC has identified April 28, 2009 as the date on which normal operations began.

CDPHE should have analyzed visibility impacts due to GCC as either a permit modification (Mod 5) or as a RP source (Mod 4). To date, CDPHE has not considered the impacts of the source under either program. Had CDPHE compared GCC's emissions (Q) as a function of distance (d) to the threshold Q/d > 20 used to determine whether a source would be included in the RP analysis, GCC would have qualified for RP review. CDPHE contends that GCC was not included in the RP review because CDPHE used 2007 emissions to determine which sources were subject to RP review, and GCC did not begin normal operations until 2009. However, in its analysis of the proposed permit modification (Mod 5), CDPHE asserts that GCC's actual emissions should be based upon the current (Mod 4) permit limits, not zero emissions. In that case, GCC's permit emissions should have been used to trigger inclusion in the Colorado RP analysis.

It is essential that any regulatory program try to maintain a "level playing field." There are two other cement plants in Colorado, and additional NO_X controls are being required on both:

- CDPHE evaluated CEMEX cement under its BART program and determined that BART for NO_X equates to an emission limit consistent with Selective Non-Catalytic Reduction (SNCR) at 45% control. We agree with that determination.
- CDPHE evaluated Holcim Cement as part of its RP analysis and determined that NO_X RP control is SNCR (at 45% efficiency). We agree with that determination.

[1] The current application for Modification 5 was originally submitted to the APCD on October 26, 2009.

GCC has installed SNCR but the current GCC permit does not require these controls to be operated. We believe that, because the GCC permit allows emissions that exceed CDPHE's threshold for determining which sources are subject to an RP analysis, GCC should have been included as a RP source. It is likely, based upon CDPHE's actions regarding the other two cement plants, that CDPHE would have required continuous operation[2] of SNCR at GCC. EPA should therefore require that GCC reduce NO_X emissions by 45% on a continuous basis, consistent with the limits it proposes to approve on the other two Colorado cement plants that contribute to visibility impairment.

[2] The current GCC permit includes a provision stating, "GCC will utilize SNCR system as needed for purposes of NOx emission reductions."

NPS Comments on Best Available Retrofit Technology and Reasonable Progress Analyses of Control Options for Nitrogen Oxides (NO_X) from Tri-State Generation & Transmission Association, Inc. – Craig Station Units 1 & 2
May 25, 2012

Background

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station (Craig) is located in Moffat County approximately 2.5 miles southwest of the town of Craig, Colorado. This facility is a coal-fired power plant with a total net electric generating capacity of 1,264 MW, consisting of three units. Of 1,237 plants, EPA Clean Air Markets (CAM) data for 2011 rank the Craig facility #25 for NO_X at 13,697 tons. There are thirteen Class I areas within 300 km of Craig (see attached map), four of which (Rocky Mountain, Black Canyon of the Gunnison, Arches, and Canyonlands National Parks) are administered by the National Park Service (NPS).The cumulative impacts of Craig on visibility across the eight Class I areas we modeled (see technical description in Appendix C to these comments) is at least[1] 21 deciviews (dv), which ranks this facility among the highest[2] of any we have evaluated under the Best Available Retrofit Technology (BART) program.

Units 1 and 2 were placed in service in 1980, and 1979, respectively, and are BART-eligible. Unit 3 started in 1984 and is not BART-eligible, but is subject to evaluation under the Reasonable Progress (RP) provisions of EPA's Regional Haze Rule. We address controls for all three units in these comments.

Units 1 and 2 are similar (each 4,318 mmBtu/hour, 428 MW net) dry-bottom, wall-fired electric generating units (EGUs) burning primarily sub-bituminous coal, with some western bituminous coal. According to EPA's BART Guidelines, the presumptive limit for a dry-bottom, wall-fired EGU is 0.23 lb/mmBtu for sub-bituminous coal.[3] These EGUs are equipped with fabric filter systems for controlling particulate matter emissions, and wet limestone Flue Gas Desulfurization (FGD) systems for the control of sulfur dioxide emissions. The boilers are equipped with Ultra-Low-NO_X (ULNB) dual-register burners with overfire air (OFA) for minimization of NO_X emissions. The FGD and ULNB systems were required to be installed and fully operational by December 31, 2004, as a result of a consent decree with the Sierra Club (signed January 10, 2001).

Of 3,621 EGUs, 2011 EPA's CAM data rank Units 1 and 2 at #112 (4,003 tons) and #76 (4,700 tons), respectively for NO_X. Our modeling data show that Craig Units 1 and 2 each has a maximum impact at Mt. Zirkel Wilderness Area of 2.35 and 2.34 dv, respectively. Cumulative impacts from Craig Units 1 and 2 across the eight Class I areas modeled by NPS are each 9dv.

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[1] NPS modeled impacts against annual average background visibility while CDPHE modeled against the 20% best background conditions.

[2] The higher are Cholla Generating Station, Coronado Generating Station, Four Corners Power Plant, Navajo Generating Station, Centralia, PGE Boardman, San Juan Generating Station.

[3] In comment #38 of its October 26, 2010 letter to CDPHE, EPA Region 8 notes that the coal burned at Craig is sub-bituminous. We have requested clarification on the presumptive BART limit for these boilers given the use of the bituminous coal.

CAM data rank Unit 3 at #67 (4,993 tons) for NO_X. Our modeling data show that Craig Unit 3 has a maximum impact at Mt. Zirkel Wilderness Area of 2.19 dv. Cumulative impacts from Craig Unit 3 across the eight Class I areas modeled by NPS are 8 dv.

Class 1 Area	Base Case 98th %				Base Case days/yr > 0.5 dv			
	Unit 1	Unit 2	Unit 3	Facility	Unit 1	Unit 2	Unit 3	Facility
Black Canyon	0.31	0.30	0.30	0.87	5	5	4	15
Eagle's Nest	1.22	1.20	1.16	2.84	43	32	42	112
Flat Tops	1.86	1.84	1.61	3.98	86	86	77	143
Maroon Bells-Snowmass	0.61	0.60	0.58	1.65	13	13	10	46
Mt. Zirkel	2.35	2.34	2.19	5.02	183	182	161	278
Rawah	1.11	1.09	1.11	2.84	64	62	55	123
Rocky Mountain	1.20	1.18	1.25	3.22	56	55	53	167
West Elk	0.50	0.50	0.49	1.41	8	8	7	27
Cumulative	8.86	8.75	8.39	20.96	454	437	404	896

EPA Region 8 (R8) conducted no additional analysis of Colorado Department of Public Health and Environment's (CDPHE) BART and proposal for the Craig power plant.[4] Instead, EPA R8 simply noted:

> The State determined that SNCR was reasonable for BART for both Unit 1 and Unit 2 based on the cost effectiveness and visibility improvement associated with this level of control. The State determined SCR was not reasonable because of the high cost effectiveness value.

The "high cost effectiveness value(s)" cited by EPA R8 are a result of overestimates of Selective Catalytic Reduction (SCR) costs and underestimates of its effectiveness by CDPHE and EPA R8, as well as underestimates of the resulting visibility improvements.

Selective Catalytic Reduction (SCR) Effectiveness

EPA R8 evaluated six coal-fired EGUs (Colstrip units 1 – 4, Corette, Lewis & Clark) in Montana[5] and assumed that SCR could achieve 0.05 lb/mmBtu (annual average) at each. In its October 26, 2010 comments to CDPHE[6], EPA R8 advised that SCR can achieve 0.03 – 0.06 lb/mmBtu.[7] However, in its proposal for Craig, EPA R8 has now underestimated the ability of modern SCR to reduce NO_X emissions at Craig by assuming that it can do no better than 0.07 lb/mmBtu on an annual basis.[8] Because such an underestimate adversely changes the cost-benefit analysis, we conducted our analysis as discussed below.

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[4] By comparison, EPA Region 8 conducted extensive and independent analyses of North Dakota's proposed BART determinations.

[5] ENVIRONMENTAL PROTECTION AGENCY 40 CFR Part 52 [EPA–R08–OAR–2011–0851; FRL–9655–7] Approval and Promulgation of Implementation Plans; State of Montana; State Implementation Plan and Regional Haze Federal Implementation Plan AGENCY: Environmental Protection Agency. ACTION: Proposed rule. Federal Register / Vol. 77, No. 77 / Friday, April 20, 2012

[6] For its cost-effectiveness analysis, CDPHE estimated that LNB+OFA+SCR can achieve 0.07 lb/mmBtu on an annual basis, which represents a 75% reduction by SCR from the emission rate to be achieved by LNB+OFA alone.

[7] EPA comments #9 and #42.

[8] It is unclear to us why EPA changed its assumptions.

It is generally assumed that SCR can achieve at least 90% NO_X reduction and 0.05 lb/mmBtu (or lower) on typical coal-fired boilers. For example, EPA Region 5 advised Minnesota that:

> We believe that the available evidence indicates that Xcel Energy's Sherburne County facility (Sherco) should add selective catalytic reduction (SCR) to the recommended nitrogen oxides (NO_X) combustion controls. We are basing this on calculations we have performed evaluating SCR at emission levels of 0.05 pounds per million British Thermal Units (lb/MMbtu) and 0.08 lb/MMBtu. Both of which are considered cost-effective. We chose to evaluate these two emission levels because you assumed a 0.08 lb/MMBTU level in your analyses and because we believe that the lower limit of 0.05 lb/MMBTU is generally achievable by this control technology. [9]

EPA Region 6's (R6) evaluation of NO_X BART for the San Juan Generating Station (SJGS) (included in Appendix A) provides a good example of a thorough technical analysis. [10] It is especially valuable to note that the boilers at SJGS are dry-bottom, wall-fired units like Craig in size and configuration and were previously required to meet a NO_X limit of 0.30 lb/mmBtu (30-day rolling average), which is similar to current NO_X emissions from Craig. In making its final determination, EPA R6 stated:

> For the reasons discussed in our proposal (76 FR 491), and in other responses to comments, we have concluded that BART for the SJGS is an emission limit of 0.05 lbs/MMBtu, based on a 30 BOD[11] average, more stringent than the levels achievable by the SNCR technology recommended by the State.

We agree with EPA R6's determination that SJGS can meet 0.05 lb/mmBtu on a 30-day rolling average and we have conducted our analyses on the (less-stringent) basis that Craig can meet 0.05 lb/mmBtu on an annual average,[12] as opposed to the assumption by CDPHE and EPA R8 that SCR can only achieve 0.07 lb/mmBtu on an annual average. To further support our conclusion, we are providing updated CAM data (Appendix A) that again shows that, in 2011,

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[9] June 6, 2011 letter from Doug Aburano, Chief, Control Strategies Section, EPA Region 5 to John Seltz, Chief, Air Assessment Section, Minnesota Pollution Control Agency

[10] **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. 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 has a unit capacity of 544 MW. Consent Decree: On March 5, 2005, 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 to settle alleged violations of the Clean Air Act. The CD required PNM to meet 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 LNB with OFA ports and a neural network system to reduce NO_X emissions.

[11] Boiler Operating Days

[12] In its comments on SJGS, EPA R6 noted that: The NPS and the USFS separately stated they believe PNM has underestimated the ability of SCR to reduce emissions. For example, the NPS states that B&V assumed that SCR could achieve 0.05 lbs/MMBtu (annual average) when evaluating retrofitting of SCR at the Craig power plant in Colorado. Both the NPS and the USFS stated that EPA's Clean Air Markets data, and vendor guarantees show that SCR can typically meet 0.05 lb/MMBtu (or lower) on an annual average basis. The USFS stated NOX emissions can be reduced by 90% with SCR installed at 0.05 lbs/MMBtu emission limit. The NPS included data it claims indicates that SCR can achieve year-round emissions of 0.05 lbs/MMBtu or lower at 26 coal-fired EGUs, eleven of which are dry-bottom, wall-fired units like SJGS. The USFS also referenced this data. The NPS believes PNM has not provided any documentation or justification to support the higher values used in its analyses. They also present information from industry sources that supports their understanding that SCR can achieve 90% reduction and reduce emissions to 0.05 lb/MMBtu or lower on coal-fired boilers. **We agree with the NPS that PNM has underestimated the ability of SCR to reduce emissions. As discussed elsewhere in our response to comments, we are requiring that the units of the SJGS meet an emission limit of 0.05 lbs/ MMBtu on the basis of a 30 day rolling BOD average. (emphasis added)**

SCR achieved year-round emissions of 0.05 lbs/mmBtu or lower at 21 coal-fired EGUs, eleven of which are dry-bottom, wall-fired units like Craig.

Finally, Black & Veatch (B&V), Tri-State's NO_X control consultant, based its study[13] of SCR control costs at Craig on a 0.05 lb/mmBtu "Design Criteria NO_X Emission Rate (lb/MBtu) at Outlet."

We corrected EPA's analysis to determine how much additional NO_X would be removed if EPA had used 0.05 lb/mmBtu as the annual emission rate instead of the 0.07 lb/mmBtu and found that an additional 374 (10%) tpy, 498 (13%) tpy and 1,333 (31%) tpy would be removed from units 1, 2 and 3, respectively.

SCR Costs

Our review of Tri-State's BART submittals for SCR at Craig leads us to conclude that Tri-State's SCR costs are overestimated. A critical cost element is the Total Capital Investment (TCI), and SCR TCI costs can be expected to fall between $50 and $300/kW, with the recent average around $200/kW. Tri-State's TCI estimates for SCR at Craig are the highest we have seen at $490 - $514/kW, and are not properly supported.

In comment #36 in EPA R8's October 26, 2010 letter to CDPHE, EPA states that "the costs for SCR at Craig do not seem to have been calculated correctly." In its comments #46 and #47, EPA R8 notes that Tri-State's cost estimates are "unusually high" and were not justified. We cannot find evidence in the docket that EPA R8's initial concerns were addressed, yet EPA R8 now appears to be accepting similar estimates.

<u>"Real-World" SCR Capital Costs</u>

Figure 3 of Tri-State's Exhibit 19 (in Appendix B), which it presented to the Colorado Air Pollution Control Commission, includes a survey of industry SCR cost data that shows that typical SCR costs for units the size of Craig would be less than $300/kW, and no SCR installation would exceed $400/kW.

Real-world, utility-industry-generated evidence that Tri-State has overestimated its SCR costs can also be found in a June 2009 article in "Power" magazine:[14]

> 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

[13] B&V Report "**NOX Emissions Control Study**" Prepared For: Tri-State Generation and Transmission Association Inc. Craig Station Units 1, 2, and 3 November 2010, Final Report TRI-STATE - RH2 EXHIBIT 16

[14] 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/

> 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...
>
> 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 all lower than estimated by Tri-State for Craig:

- The first study evaluated the installed costs of more than 20 SCR retrofits from 1999 to 2001. The installed capital cost ranged from $111 to $223/kW, converted to 2010 dollars.[15]
- The second survey of 40 installations at 24 stations reported a cost range of $79 to $253/kW, converted to 2010 dollars.[16]
- 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 $124/kW to $274/kW, converted to 2010 dollars.[17]
- A fourth study, presented in a course at PowerGen 2005, reported an upper bound range of $188/kW to $212/kW, converted to 2010 dollars.[18]
- 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.[19]

EPA R8 has compiled a graphic presentation of SCR capital costs adjusted to 2009 dollars—please see Appendix B for "SCR References Colorado". The EPA data confirm that SCR capital costs typically range from $73 – $243/kW and that cost estimates presented by Tri-State/B&V are significantly overestimated. Tri-State/B&V have not demonstrated unique features for Craig that would justify a cost estimate twice the range for the industry.

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[15] Bill Hoskins, Uniqueness of SCR Retrofits Translates into Broad Cost Variations, Power Engineering, May 2003. The reported range of $80 to $160/kW $123 - $246/kW in 2002 $ was converted to 2010$ using the CEPCI ratio.

[16] J. Edward Cichanowicz, Why are SCR Costs Still Rising?, Power, April 2004, Ex. 3; Jerry Burkett, Readers Talk Back, Power, August 2004. The reported range of $56/kW - $185/kW in 1999$ - 2003$ was converted to 2010$ using the CEPCI ratio, based on Figure 3.

[17] M. Marano, Estimating SCR Installation Costs, Power, January/February 2006. The reported range of $100 - $221/kW was converted to 2010$ using the CEPCI ratio. http://findarticles.com/p/articles/mi_qa5392/is_200602/ai_n21409717/print?tag=artBody;col1

[18] PowerGen 2005, Selective Catalytic Reduction: From Planning to Operation, Competitive Power College, by Babcock Power, Inc. and LG&E Energy, December 2005. The reported range of $160 - $180/kW was converted to 2010$ using the CEPCI ratio.

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

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, that SCR installation cost $205/kW.[20] It should also be noted that the Boswell #3 retrofit was designed to meet 0.05 lb/mmBtu. Burns & Mc Donnell 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)."

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 in North Carolina, reported to cost $265/kW,[21] or Cinergy's Gibson Units 2-4 in Indiana. 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 $249/kW in 2010 dollars.[23]

EPA R6 addressed a similar problem with the SJGS analysis:

> PNM scaled many of the cost items from another project that has significant design differences when compared to the SJGS. We made changes iu many of these items to adjust them from budgetary to final contract; to exclude equipment and modifications not required for the SJGS SCR installations; to correct errors; and to factor out installation, freight, and other costs that were included in the contract awards and double counted elsewhere in PNM's cost estimate. We have concluded that these adjustments are correct, and provide a more accurate estimate of the costs at SJGS.

This is particularly relevant for the issue at hand because Tri-State and B&V relied upon the same St. John River project in Florida to derive their Craig estimates as PNM and B&V incorrectly used for SJGS. EPA R6's excellent detailed review of the B&V cost analysis for SJGS is included in Appendix B, and we believe that EPA R8 should have conducted a similar review of B&V's analysis for Craig.

We have several additional concerns with the Tri-State/B&V analysis:

- Tri-State did not provide information recommended by the BART Guidelines[24] to support its cost details. Rather, Tri-State's estimates were, apparently, simply scaled from the St. John River power plant in Florida with significantly different issues.
- Tri-State stated that "Escalation is included for most items, including labor" but did not explain what costs were escalated and how. Escalation factors are not typically allowed in cost estimations.[25]

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[20] 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.

[21] Steve Blankinship, SCR = Supremely Complex Retrofit, Power Engineering, November 2002. The unit cost: ($325,000,000/1,120,000 kW)(608.8/395.6) = $290/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

[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 $249/kW in 2010$ using the CEPCI ratio. http://www.mcilvainecompany.com/sampleupdates/NoxMarketUpdateSample.htm

[24] 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)

[25] "Estimating real annual costs means no use of escalation factors..." Larry Sorrels (economist at EPA's Office of Air Quality Planning and Standards) e-mail dated September 7, 2010 to Don Shepherd of NPS

- Tri-State claimed lost generation costs of $12 - $18 million but provided no support or justification for the costs, the duration of the outages needed, and why time beyond normal scheduled outages would be necessary.
- Tri-State included a $26 million per unit Allowance for Funds Utilized During Construction (AFUDC). This cost is not allowed because Tri-State is not a rate-regulated utility and the AFUDC cost is not "already included in the base case as per a utility commission decision." [26]

In conducting our cost analysis of SCR at Craig, we used an approach similar to that used by EPA R8 in its evaluation of SCR on the Colstrip power plant—following is an excerpt from EPA R8's proposed Montana FIP:

> We relied on a number of resources to assess the cost of compliance for the control technologies under consideration. In accordance with the BART Guidelines (70 FR 39166), and in order to maintain and improve consistency, in all cases we sought to align our cost methodologies with the EPA CCM.[27] However, to ensure that our methods also reflect the most recent cost levels seen in the marketplace, we also relied on a set of cost calculations developed for the Integrated Planning Model (IPM) version 4.10.[28] These IPM cost calculations are based on databases of actual control project costs and account for project specifics such as coal type, boiler type, and reduction efficiency. The IPM cost calculations reflect the recent increase in costs in the five years proceeding 2009 that is largely attributed to international competition. Finally, our costs were also informed by cost analyses submitted by the sources, including in some cases vendor data.
>
> Annualization of capital investments was achieved using the CRF [Capital Recovery Factor] as described in the CCM.[29] Unless noted otherwise, the CRF was computed using an economic lifetime of 20 years and an annual interest rate of 7%.[30] All costs presented in this proposal have been adjusted to 2010 dollars using the Chemical Engineering Plant Cost Index (CEPCI).[31]

For Craig Unit 1, we used EPA's IPM model to estimate Direct Capital Cost (DCC) at $67 million,[32] which is substantially lower than the $122 million DCC estimated by Tri-State/B&V. We used the IPM estimate for DCC and then applied the EPA Control Cost Manual (CCM) factors (totaling 141%) for Indirect Capital Cost to estimate a Total Capital Investment (TCI) of $94 million ($221/kW) versus $210 million ($490/kW) estimated by Tri-State/B&V. Next, we applied the CCM methods for estimating Direct and Indirect Annual Costs to the TCI and arrived at a Total Annual Cost of $12.5 million for SCR with combustion control improvements. We concluded that combustion controls plus SCR for Units 1 and 2 would remove almost 5,700 tpy and cost about $2,200/ton. We applied the same approach to Craig 2 and 3 and arrived at the similar values in the table below. (Excel workbooks in Appendix B contain details of our calculations.)

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[26] "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." Larry Sorrels 7/21/10 e-mail to Don Shepherd

[27] EPA Control Cost Manual Sixth Edition, January 2002, EPA 452/B–02–001

[28] Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model, August 2010, EPA #430R10010

[29] Section 1, Chapter 2, page 2-21.

[30] Office of Management and Budget, Circular A-4, Regulatory Analysis, http://www.whitehouse.gov/omb/circulars_a004_a-4/.

[31] Chemical Engineering Magazine, p. 56, August 2011. (*http://www.che.com*).

[32] after adjusting to 2010$ using the CEPCI

Unit	Unit #1	Unit #2	Unit #3
Rating (MW Gross) each	428	428	408
Rating (mmBtu/hr)	4,843	4,739	4,843
Combustion Controls Cost-benefit Analysis			
Controlled emissions (lb/mmBtu)	0.28	0.28	0.30
Emissions Reduction (tpy)	1,498	2,114	1,031
Capital Cost	$ 6,552,449	$ 6,552,449	$ 6,552,449
Annualized Cost	$ 618,505	$ 618,505	$ 618,505
Cost-Effectiveness ($/ton)	$ 413	$ 293	$ 600
SCR Cost-benefit Analysis			
Control Efficiency	82%	82%	83%
Controlled emissions (lb/mmBtu)	0.05	0.05	0.05
Emissions Reduction (tpy)	4,165	4,161	4,220
Capital Cost	$ 94,384,846	$ 92,557,948	$ 94,609,170
Capital Cost ($/kW)	$ 221	$ 216	$ 232
O&M Cost	$ 2,980,538	$ 2,955,487	$ 2,973,483
Annualized Cost	$ 11,889,800	$ 11,692,303	$ 11,903,919
Cost-Effectiveness ($/ton)	$ 2,855	$ 2,810	$ 2,821
Combustion Controls + SCR Cost-benefit Analysis			
Control Efficiency	86%	87%	86%
Controlled Emissions (tpy)	898	920	859
Emissions Reduction (tpy)	5,662	6,275	5,251
Capital Cost	$ 100,937,295	$ 99,110,397	$ 101,161,619
Capital Cost ($/kW)	$ 236	$ 232	$ 248
O&M Cost	$ 2,980,538	$ 2,955,487	$ 2,973,483
Annualized Cost	$ 12,508,304	$ 12,310,808	$ 12,522,424
Cost-Effectiveness ($/ton)	$ 2,209	$ 1,962	$ 2,385

The table below compares critical values estimated by EPA and NPS.[33]

	Unit 1		Unit 2		Unit 3	
	EPA (1)	NPS	EPA (2)	NPS	EPA (3)	NPS
Reference Case (tpy)	5,190	5,063	5,372	5,081	6,463	5,079
SCR Total Annual Cost	$ 25,036,709	$ 11,889,800	$ 25,036,709	$ 11,692,303	$ 29,761,512	$ 11,903,919
SCR Efficiency	74.9%	82%	74%	82%	75%	83%
Reduction from Reference Case (tpy)	3,893	4,165	3,893	4,161	4281	4,220
SCR $/ton	$ 6,431	$ 2,855	$ 6,431	$ 2,810	$ 6,952	$ 2,821

(1) from EPA TABLE 12—SUMMARY OF CRAIG UNIT 1 NOX BART ANALYSIS

(2) from EPA TABLE 13—SUMMARY OF CRAIG UNIT 2 NOX BART ANALYSIS

(3) from EPA TABLE 40—SUMMARY OF TRI-STATE CRAIG UNIT 3 NOX RP ANALYSIS

The primary cause of the higher cost/ton derived by Tri-State/B&V is the annual cost that is more than double our estimates that we derived by applying the same approach that EPA R8

[33] Highlighted values are corrections to EPA errors.

used for the Colstrip power plant in Montana. The Tri-State/B&V overestimates of the Total Annual Cost are primarily due to the significant overestimates of Total Capital Investment.

Although OAQPS guidance recommends evaluating Average Costs[34] and benefits relative to the "no control" 2001 – 2003 BART baseline period, EPA R8 has based its analysis entirely upon the incremental costs and benefits of adding SCR to the improved combustion controls that were installed in 2003. If we only consider the incremental cost of adding SCR at a Total Annual Cost of about $12 million/yr versus its incremental benefit of reducing emissions by almost 4,200 tpy, the incremental cost-effectiveness becomes approximately $2,800/ton for each unit, which is well below Colorado's $5,000/ton threshold for BART.

SCR Visibility Benefits

Even though there are 13 Class 1 areas within 300 km of Craig, EPA R8 only reported visibility impacts and improvements at one Class I area (which we believe to be Mount Zirkel Wilderness Area). Instead, 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 1 areas affected. If reducing emissions from a BART source impacts multiple Class I areas, then a BART determination should incorporate those benefits. It is not justified to evaluate impacts at one Class I area, while ignoring others that are similarly significantly impaired by the BART source. If emissions from the BART source are reduced, the benefits will be spread well beyond only the most-impacted Class I area, and these benefits are an integral part of the BART determination.[35] In comment #10 of its October 26, 2010 letter to CDPHE, EPA R8 states:

> The visibility results section in each analysis only addresses visibility improvements at the most-impacted Class I area. Since visibility improvements are also likely at other nearby Class I Areas, the State needs to provide visibility modeling information for other Class I areas. This information will help inform the selection of BART.

There is no evidence in the docket to show that EPA R8 evaluated visibility results for "other nearby Class I Areas" or that it considered such improvements to "inform the selection of BART." We are providing that information.

The BART Guidelines attempt to create a workable approach to estimating visibility impairment. The Guidelines do not attempt to address the geographic extent of the impairment, but in effect assume that all Class I areas are created equal, i.e., widespread impacts in a large Class I area and isolated impacts in a small Class I area are given equal weight for BART determination purposes. To address the problem of geographic extent, we look at the cumulative impacts of a source on all Class I areas affected, as well as the cumulative benefits from reducing emissions. While there may be more sophisticated approaches to this problem, we believe that this is the most practical, given current modeling techniques and information available. EPA R6 took a similar position regarding its BART determination for the San Juan Generating Station (SJGS):

> We agree with the NPS and the USDA Forest Service on the utility of a cumulative visibility metric in addition to the other visibility metrics we utilized and we do not agree that our approach is inconsistent

[34] Average Costs for BART (LNB+OFA+SCR) at Craig are $1900 - $2400/ton.

[35] For example, the 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, SJGS, and the Four Corners Power Plant. EPA also sums impacts and benefits in proposing that the Clean Air Transport Rule is "better-than-BART."

with BART guidelines. Our visibility modeling shows that a number of Class I areas are individually and significantly impacted by emissions from the SJGS. The number of days per year significantly impacted by the facility's NO_X emissions is expected to decrease drastically at each Class I area (Table 6-8 of the TSD) as the result of installation of NO_X BART emission controls at the SJGS. Clearly, the visibility benefits from NO_X BART emission reductions will be spread among all affected Class I areas, not only the most affected area, and should be considered in evaluation of benefits from proposed reductions.
In fully considering the visibility benefits anticipated from the use of an available control technology as one of the factors in selection of NO_X BART, it is appropriate to account for visibility benefits across all affected Class I areas and the BART guidelines provide the flexibility to do so. One approach as noted above is to qualitatively consider, for example, the frequency, magnitude, and duration of impairment at each and all affected Class I areas. Where a source such as the SJGS significantly impacts so many Class I areas on so many days, the cumulative `total dv' metric is one way to take magnitude of the impacts of the source into account.

We concluded that a quantitative analysis of visibility impacts and benefits at only the Mesa Verde area would not be sufficient to fully assess the impacts of controlling NOX emissions from the SJGS.

Again, nothing in the RHR suggests that a state (or EPA in issuing a FIP) should ignore the full extent of the visibility impacts and improvements from BART controls at multiple Class I areas. Given that the national goal of the program is to improve visibility at all Class I areas, it would be short-sighted to limit the evaluation of the visibility benefits of a control to only the most impacted Class I area. As noted previously, NMED and PNM's BART analyses also presented visibility impact and improvement projections at all 16 Class I areas. We believe such information is useful in quantifying the overall benefit of BART controls. [36]

EPA R1 also considered cumulative benefits in its evaluation of New Hampshire's regional haze plan.[37]

NPS Modeling Analysis

While CDPHE's air quality modeling analysis followed its EPA-approved protocol, we found that certain inputs did not properly represent the appropriate 24-hour emissions:

- Boiler heat inputs used by CDPHE were lower than the maximum 24-hour rates we found in CAM; this resulted in estimates by CDPHE that underestimated maximum 24-hour emissions.
- CDPHE modeled 30-day rolling average emission rates instead of 24-hour emissions, which would typically be higher.
- CDPHE did not model condensable PM emissions, which typically constitute about half of total PM for boilers like these.

[36] ENVIRONMENTAL PROTECTION AGENCY 40 CFR Part 52, EPA-R06-OAR-2010-0846; FRL-9451-1, Approval and Promulgation of Implementation Plans; New Mexico; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determination, AGENCY: Environmental Protection Agency (EPA). ACTION: Final rule. Federal Register / Vol. 76, No. 162 / Monday, August 22, 2011

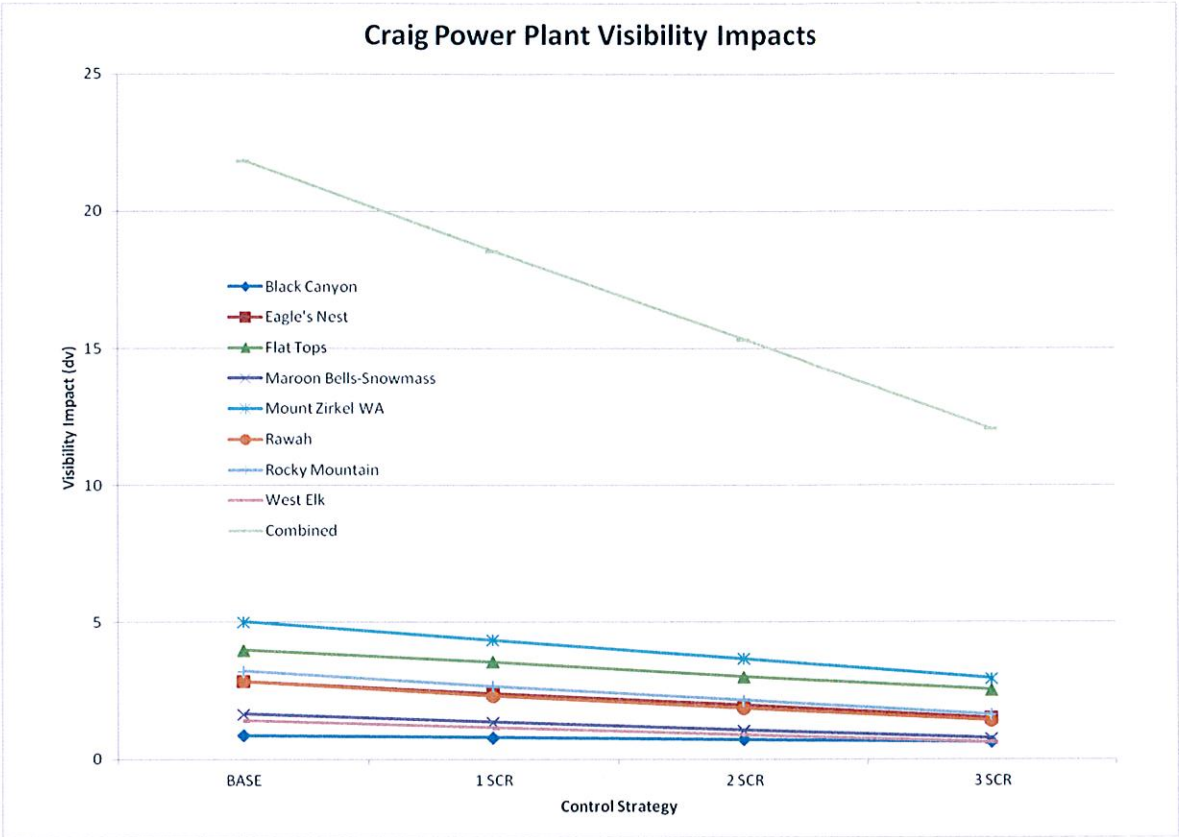
[37] ENVIRONMENTAL PROTECTION AGENCY40 CFR Part 52, [EPA–R01–OAR–2008–0599; A–1–FRL–9639–1], Approval and Promulgation of Air Quality Implementation Plans; New Hampshire; Regional Haze AGENCY: Environmental Protection Agency, ACTION: Proposed rule., Federal Register /Vol. 77, No. 39 /Tuesday, February 28, 2012

Although CDPHE modeled all Colorado Class I areas within 300 km to determine base case impacts, in its analysis of the benefits of various control scenarios, it presented results for only Mt. Zirkel, the most-impacted Class I area.

For the reasons above, NPS conducted an independent modeling analysis. We used the CDPHE air quality modeling files to conduct our own visibility impact analysis to evaluate the effectiveness of the different proposed control technology scenarios. The air quality modeling was performed using the EPA Guideline model CALPUFF version 5.8, POSTUTIL version 5.8 and CALPOST version 6.221. The three years (2001, 2002, and 2003) 4 km CALMET data was supplied by the CDPHE. The CALMET data set was generated following the EPA Guidance memorandum of August 31, 2009, "Clarification on EPA-FLM Recommended Settings for CALMET". Monthly ammonia concentrations in both CALPUFF and POSTUTIL were set at 1.0 parts per billion (ppb). The concentrations from the CALPUFF output were post processed using the POSTUTIL model with the setting MNITRATE=1 to re-compute the HNO_3/NO_3 partition for concentrations to be applied in the visibility analyses.

Eight Class I areas within 200 km were modeled and the receptors for the Class I areas were from the NPS's Class I areas receptor data base. Visible haze calculations were performed with CALPOST version 6.221 using Method 8 Mode 5 (annual average visibility) and the new IMPROVE equation. Annual average natural background conditions, concentrations, and the monthly f (RH) factors per Class I area were from the Federal Land Managers Air Quality Workgroup (FLAG) 2010 document.

The NPS analysis differs from the CDPHE's approved protocol in two ways. The CDPHE air quality analysis used CALPOST version 5.6394 and for natural background CDPHE used Method 6 (the 20% best visibility days) as allowed by EPA. (Our analyses are described in greater detail in Appendix C.) Our results show that Craig Units 1 and 2 each has a maximum impact at Mt. Zirkel Wilderness Area of 2.35 and 2.34 dv, respectively, and that Craig Unit 3 has a maximum impact at Mt. Zirkel Wilderness Area of 2.19 dv. We also modeled scenarios in which one SCR was added (to Unit 2), two SCRs were added (to Units 1 & 2), and three SCRs were added to the three units. Our results for the Class I areas modeled are presented individually and cumulatively below:



It is apparent from the chart above that the EPA R8 proposal to add one SCR will not eliminate the impairment caused by Craig at any of the Class I areas modeled. Our evaluation of the NPS modeling results (Appendix C) for each scenario revealed that the improvement (e.g. 1.2 dv at Mt. Zirkel) realized as each SCR was added was essentially linear—the same amount of visibility improvement occurred when each successive SCR was added, and there was no situation where we saw "diminishing returns."[38]

The results below are for the base case and the addition of SCR to each Craig unit.

	Base Case 98th %				SCR 98th %			
Class I Area	Unit 1	Unit 2	Unit 3	Facility	Unit 1	Unit 2	Unit 3	Facility
Black Canyon	0.31	0.30	0.30	0.87	0.22	0.21	0.21	0.63
Eagle's Nest	1.22	1.20	1.16	2.84	0.54	0.53	0.55	1.51
Flat Tops	1.86	1.84	1.61	3.98	1.06	1.04	0.79	2.54
Maroon Bells-Snowmass	0.61	0.60	0.58	1.65	0.27	0.26	0.25	0.76
Mt. Zirkel	2.35	2.34	2.19	5.02	1.19	1.18	0.96	2.95
Rawah	1.11	1.09	1.11	2.84	0.51	0.50	0.52	1.42
Rocky Mountain	1.20	1.18	1.25	3.22	0.56	0.54	0.56	1.63
West Elk	0.50	0.50	0.49	1.41	0.22	0.21	0.21	0.63
Cumulative	8.86	8.75	8.39	20.96	4.35	4.27	3.83	11.43

[38] We also observed that nitrate was the dominant contributor to visibility impairment until the third SCR was added, at which point sulfate became dominant.

Class I Area	Base Case days/yr > 0.5 dv				SCR days/yr > 0.5 dv			
	Unit 1	Unit 2	Unit 3	Facility	Unit 1	Unit 2	Unit 3	Facility
Black Canyon	5	5	4	15	1	1	1	13
Eagle's Nest	43	32	42	112	9	9	9	73
Flat Tops	86	86	77	143	49	48	31	116
Maroon Bells-Snowmass	13	13	10	46	2	2	2	22
Mt. Zirkel	183	182	161	278	108	106	52	226
Rawah	64	62	55	123	9	8	8	107
Rocky Mountain	56	55	53	167	10	9	11	94
West Elk	8	8	7	27	1	1	1	13
Cumulative	454	437	404	896	188	183	114	651

Class I Area	Improvement 98th %				Reduced days/yr > 0.5 dv			
	Unit 1	Unit 2	Unit 3	Facility	Unit 1	Unit 2	Unit 3	Facility
Black Canyon	0.09	0.09	0.09	0.24	4	4	3	2
Eagle's Nest	0.68	0.68	0.62	1.34	34	23	32	40
Flat Tops	0.80	0.79	0.83	1.44	38	38	46	27
Maroon Bells-Snowmass	0.34	0.34	0.33	0.89	11	11	8	24
Mt. Zirkel	1.16	1.16	1.23	2.07	76	76	108	52
Rawah	0.60	0.59	0.60	1.43	55	54	47	16
Rocky Mountain	0.64	0.63	0.69	1.59	46	46	42	73
West Elk	0.29	0.29	0.28	0.78	6	7	6	14
Cumulative	4.51	4.48	4.56	9.53	266	254	290	246

SCR added to each unit achieves at least a 0.5 dv improvement, and in some cases more than twice that, at each of five Class I areas.

BART Determination

EPA R8 has determined that BART for Craig 1 and 2 is 0.27 lb/mmBtu, and RP for Unit 3 is 0.28 lb/mmBtu, all on a 30-day rolling average.

Although EPA R8 provided presumptive BART limits for NO_X for the Xcel Energy "BART Alternative," it provided no insight as to what it considers the presumptive BART limit to be for Craig.[39] A critical factor in determining the presumptive BART limit is the type of coal burned. In its BART report, CDPHE states:

> Tri-State notes that the Craig boilers burn Colorado coal that primarily comes from the Trapper mine, supplemented by ColoWyo coal, which are both high-ranking subbituminous coal. Limited amounts of coal from the Twentymile mine, ranked as bituminous, are also burned.

Because EPA R8 has not adequately addressed our requests for its determination of presumptive BART, we recommend that presumptive BART for Craig should be based upon the primary type of coal burned there, which, as CDPHE states, is sub-bituminous. When classifying boilers based upon fuel type, EPA typically uses the predominant fuel and we believe this should be the basis

[39] The BART Guidelines and presumptive BART limits apply to facilities with greater than 750 MW generating capacity, like Craig.

for determining presumptive BART. We therefore recommend that EPA R8 establish the presumptive BART limit for Craig at 0.23 lb/mmBtu because of its predominant use of sub-bituminous coal. On that basis, the limits proposed by EPA R8 exceed presumptive BART.

We understand that Tri-State has expressed concern that its coal supply may shift toward more use of the bituminous Twentymile coal in the future. If this happens, it is also likely that NO_X emissions at Craig would increase, and the need for SCR (and its cost-effectiveness) would increase as well.

Cost-Effectiveness Metrics

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 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 the San Juan Generating Station, New Mexico used a range from $5,946/ton to $7,398/ton, and Wisconsin is using $7,000 - $10,000/ton as its BART threshold.[40] In its proposal to disapprove part of the North Dakota plan, EPA R8 stated:

> In our BART analysis for NOx at Milton R. Young Station 1, we considered SNCR + ASOFA and SCR + ASOFA...We have concluded that SNCR + ASOFA and SCR + ASOFA are both cost effective control technologies and that both would provide substantial visibility benefits. SNCR + ASOFA has a cost effectiveness value of $687 per ton. While SCR + ASOFA is more expensive than SNCR + ASOFA, it has a cost effectiveness value of $2,569 per ton of NOx emissions reduced. This is well within the range of values we have considered reasonable for BART and that states other than North Dakota have considered reasonable for BART. Even with more frequent catalyst replacement, SCR would still be cost effective even at the high end of the range ($2,783 per ton) allowing for the most frequent catalyst replacement of one layer per year and allowing for the questionable costs of lost power generation revenue in TESCR Scenario 4. We also analyzed the SCR costs assuming the same baseline emissions of 9,032 tons per year used by North Dakota and determined that the high-end cost effectiveness value, assuming the most frequent catalyst replacement frequency, would be about $3,115 per ton of NOx reduced. All of these cost effectiveness values are well within the range of values that North Dakota considered reasonable in several of its NOx BART determinations, where predicted visibility improvement was considerably lower.
>
> We have weighed costs against the anticipated visibility impacts at Milton R. Young Station 1, as modeled by Minnkota and the State. Both sets of controls would have a positive impact on visibility. As compared to SNCR + ASOFA, SCR + ASOFA would provide an additional visibility benefit 0.553 deciviews and 18 fewer days above 0.5 deciviews at Theodore Roosevelt. We consider these impacts to be substantial, especially in light of the fact that neither of these Class I areas is projected to meet the uniform rate of progress. We also note that the 0.553 deciview improvement at Theodore Roosevelt is greater than the improvement in visibility that North Dakota found reasonable to support other NOx BART determinations in the SIP despite higher cost effectiveness values for the sources involved in these other BART determinations. Given the incremental visibility improvement associated with SCR + ASOFA, the relatively low incremental cost effectiveness between the two control options ($4,855 per ton), and the

[40] "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

reasonable average cost effectiveness values for SCR + ASOFA, we propose that the NOx BART emission limit for Milton R. Young Station 1 should be based on SCR + ASOFA.[41]

Although EPA R8 subsequently decided not to disapprove the ND plan, its reason for changing its proposal for NO_X controls was due to issues of technical feasibility and EPA R8 did not change its determination that the costs cited above are "reasonable." Also, in its proposed Federal Implementation Plan for Montana, R8 determined that it was reasonable to spend $4,659/ton to control SO_2 and $4,415/ton for NO_X at the J.E. Corette power plant.[42]

In evaluating addition of SCR at the Four Corners Power Plant, EPA R9 stated:

> EPA considers its revised cost-effectiveness estimates of $2,515 - $3,163/ton of NOx removed to be more accurate and representative of the actual cost of compliance. However, even if EPA had decided to accept APS's worst-case cost estimates of $4,887 – $6,170/ton of NOx removed, EPA considers that estimate to be cost effective for the purpose of proposing an 80% reduction in NOx, achievable by installing and operating SCR as BART at FCPP.[43]

EPA R9 is currently requesting comments on its BART proposal for the Reid Gardner Generating Station in Nevada:

> Based on our revised cost estimates, we do not consider these average and incremental cost effectiveness values for SCR with LNB and OFA as cost prohibitive. Our analysis of this factor indicates that costs of compliance ($2000 - $2200/ton average $2700 - $4700/ton incremental) are not sufficiently large to warrant eliminating SCR from consideration.
>
> The incremental cost effectiveness values for Units 1 and 2 are around $4,500/ton. Although EPA does not consider this incremental cost prohibitive, we note that the State has certain discretion in weighing this cost. Because RGGS is not a facility over 750 megawatts and therefore not subject to EPA's presumptive BART limits, the State may exercise its discretion more broadly in this particular determination.[44]

In this case, because Craig is subject to presumptive BART, the State's discretion is limited.

EPA R6 agreed with our conclusion that $2,600/ton was a reasonable cost for adding SCR at SJGS:

> We agree with the general contention that many individual cost items for the installation of SCR on the units of the SJGS were overestimated by PNM…We note that the NPS estimate of an average cost of $2,600/ton for the four units of the SJGS closely agrees with our own revised estimate.[45]

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[41] ENVIRONMENTAL PROTECTION AGENCY 40 CFR Part 52 [EPA–R08–OAR–2010–0406; FRL–9461–7] Approval and Promulgation of Implementation Plans; North Dakota; Regional Haze State Implementation Plan; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Regional Haze AGENCY: Environmental Protection Agency (EPA). ACTION: Proposed rule. Federal Register / Vol. 76, No. 183 / Wednesday, September 21, 2011

[42] EPA R8 determined that the visibility benefits of those controls were not sufficient.

[43] ENVIRONMENTAL PROTECTION AGENCY 40 CFR Part 49 [EPA–R09–OAR–2010–0683; FRL–9213–7] Source Specific Federal Implementation Plan for Implementing Best Available Retrofit Technology for Four Corners Power Plant: Navajo Nation AGENCY: Environmental Protection Agency (EPA). ACTION: Proposed rule. Federal Register / Vol. 75, No. 201 / Tuesday, October 19, 2010

[44] ENVIRONMENTAL PROTECTION AGENCY 40 CFR Part 52 [EPA–R09–OAR–2011–0130, FRL–9658–5] Approval and Promulgation of Air Quality Implementation Plans; State of Nevada; Regional Haze State and Federal Implementation Plans; BART Determination for Reid Gardner Generating Station AGENCY: Environmental Protection Agency (EPA). ACTION: Proposed rule. Federal Register / Vol. 77, No. 71 / Thursday, April 12, 2012

[45] ENVIRONMENTAL PROTECTION AGENCY 40 CFR Part 52 EPA–R06–OAR–2010–0846; FRL–9451–1 Approval and Promulgation of Implementation Plans; New Mexico; Federal Implementation Plan for Interstate

EPA R8's comments in its Federal Register Notice on CDPHE's BART criteria are especially interesting:

> EPA does not necessarily agree that the State's criteria for selecting NO_X controls would always be appropriate. First, the criteria appear to discriminate against SCR as a potential control option. Under the criteria, if the cost of SCR is under $5,000/ton and the modeled visibility benefit is 0.20 delta dv or greater but less than 0.50 delta-dv, the State would reject SCR. Using the State's criteria, the State would find SNCR reasonable with the same $/ton and delta-dv values. We are not aware of a valid basis for applying different criteria to the two control options. In addition, we are aware of no basis for establishing benchmarks for postcombustion controls but not for other types of NO_X controls. **The criteria may also preclude a reasonable weighing of the five factors where the delta dv benefit is over 0.5 but the cost is higher than $5,000/ton. (emphasis added)**
>
> While we do not necessarily agree that the criteria used by the State would always be appropriate to select NO_X controls, we agree with the State's determinations for NO_X BART controls on the BART sources as discussed below.

Nevertheless, despite the concerns bolded above, EPA R8 has determined that, because Tri-State's estimate of the incremental cost of SCR exceeds $5,000/ton, even though the incremental visibility improvement exceeds 0.5 dv, SCR is not selected. We have shown that addition of SCR on each Craig unit costs less than $5,000/ton and achieves greater than a 0.5 dv incremental improvement.

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[46] of BART analyses across the U.S. reveals that the **average cost per dv proposed by either a state or a BART source is $14 - $18 million,**[47] with a maximum of $51 million per dv proposed by South Dakota at the Big Stone power plant. We note that, even though it has no Class I areas, Nebraska DEQ has chosen $40 million/dv as a cost criterion, which is also above the national average. (CDPHE calculated $/dv at Mt. Zirkel for each BART control option modeled, but did not say if or how those values were used in making its BART determinations.)

Applying the cost/dv approach to Craig yields about $10 million/dv for Mt. Zirkel and $2.6 million/dv on a cumulative basis[48]; both values are reasonable when compared to the national averages.

Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determination AGENCY: Environmental Protection Agency (EPA). ACTION: Final rule. Federal Register / Vol. 76, No. 162 / Monday, August 22, 2011

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

[47] For example, PacifiCorp has stated in its BART analysis for its Dave Johnston Unit #4 that "The incremental cost effectiveness for Scenario 1 compared with the baseline is reasonable at $800,000 per day and $31.7 million per deciview."

[48] In its January 21, 2011 letter to the Nebraska Department of Environmental Quality, EPA stated that "a $/dv analysis is likely to be less meaningful if the analysis does not take into account the visibility impacts at multiple Class I areas or ignores the total improvement (i.e., the frequency, magnitude, and duration of the modeled changes in visibility)."

Visibility Cost-effectiveness Analyses	Unit #1	Unit #2	Unit #3
Visibility Impact before BART (dv at Max Class I)	2.35	2.34	2.19
Visibility Impact after BART (dv at Max Class I)	1.19	1.18	0.96
Visibility Improvement (dv at Max Class I)	1.16	1.16	1.23
Cost-Effectiveness ($/98th % dv at Max Class I)	$ 10,246,883	$ 10,096,980	$ 9,672,741
Visibility Impact before BART (dv at Summed Class I)	8.86	8.75	8.39
Visibility Impact after BART (dv at Summed Class I)	4.35	4.27	3.83
Visibility Improvement (dv at Summed Class I)	4.51	4.48	4.56
Cost-Effectiveness ($/98th % dv at Summed Class I)	$ 2,635,540	$ 2,609,501	$ 2,608,792

Conclusions & Recommendations

- EPA R8 has underestimated the effectiveness of SCR by assuming that it can achieve annual average emission no lower than 0.07 lb/mmBtu, despite substantial evidence that SCR can achieve 0.05 lb/mmBtu (or lower) on an annual basis.
- EPA R8 has overestimated the cost of SCR. The costs accepted by EPA R8 substantially exceed all EPA IPM and "real-world" industry estimates.
- EPA R8 has chosen to not consider the benefits of reducing impacts on visibility in Class I areas other than the most-impacted. By comparison, other EPA regions (R6 & R9) have considered cumulative benefits.
- EPA R8 has proposed limits that exceed presumptive BART.
- EPA R8 has not provided to the public its criteria for making BART determinations for Craig. Instead, the reasoning EPA R8 appears to be using is inconsistent with EPA's BART Guidelines and the intent of the Regional Haze Rule.
- We have demonstrated that addition of SCR on each Craig unit costs less than $5,000/ton and achieves greater than a 0.5 dv incremental improvement.
- EPA R8 should determine that:
    - SCR can achieve 0.05 lb/mmBtu on an annual average on all three Craig units,
    - SCR is cost-effective on all three Craig units when compared to BART determination made by other states and EPA regions,
    - SCR can achieve substantial visibility improvement on an individual and cumulative Class I area basis, and
    - SCR is BART for Craig 1 & 2 and represents Reasonable Progress for Craig 3.