United States Department of the Interior

NATIONAL PARK SERVICE
Air Resources Division
P.O. Box 25287
Denver, CO 80225

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IN REPLY REFER TO:

March 4, 2011

N3615 (2350)

Cheryl Heying, Director
Division of Air Quality
Utah Department of Environmental Quality
P.O. Box 144820
Salt Lake City, Utah 84114 - 4820

Dear Ms. Heying:

On January 5, 2011, the Utah Air Quality Board proposed revisions to Utah's Regional Haze State Implementation Plan (SIP). Utah originally developed the SIP in 2003 and revised the SIP in 2008. The National Park Service (NPS) has reviewed the 2011 revised Regional Haze SIP for consistency with the requirements of 40 CFR 51.309(d) and appropriate sections of 40 CFR 51.308. We also reviewed the Division of Air Quality's September 2008 responses to our previous comments on the 2008 draft SIP.

The Utah Regional Haze SIP is generally responsive to the requirements of Section 51.309. We agree with Utah's 2011 updates to the Regional Haze SIP to incorporate revisions to the regional milestones and the backstop trading program for sulfur dioxide emissions. Our enclosed comments recommend additional analyses to address long-term strategies and Best Available Retrofit Technologies to further reduce emissions of nitrogen oxide and particulate matter from stationary sources, as required in section 51.309 (d) (4) (vii) and section 51.308 (d).

We appreciate the opportunity to work closely with the State of Utah through the extended planning effort to improve visibility in our Class I areas. We look forward to your response. If you have any questions, please feel free to contact me at 303-969-2153.

Sincerely,

Patricia Brewer

Patricia Brewer
Acting Chief, Air Resources Division

Enclosures

cc:
Laurel Dygowski
US EPA Region 8, 8P-AR
1595 Wynkoop Street
Denver, Colorado 80202-1129

National Park Service Comments on Utah's 2011 Revised Regional Haze Plan
March 4, 2011

The National Park Service Air Resources Division has previously reviewed Utah's 2003 and 2008 State Implementation Plans (SIPs) which addressed the requirements of the Regional Haze Rule as detailed in 40 CFR 51.309 for states implementing the recommendations of the Grand Canyon Visibility Transport Commission. We have currently reviewed Utah's 2011 proposed revisions to the Regional Haze SIP and Utah's Division of Air Quality's (DAQ) response to our previous comments. We agree with Utah's 2011 updates to the Regional Haze SIP to incorporate revisions to the milestones and backstop program for sulfur dioxide (SO_2) emissions. We commend Utah's long-term strategies for mobile sources, fire management, road dust, and renewable energy. Our comments below address the long-term strategy and Best Available Retrofit Technology (BART) requirements to further reduce emissions of nitrogen oxide (NO_x) and particulate matter (PM) from stationary sources, as required in section 51.309 (d)(4)(vii) and Utah's impact on visibility in Class I areas outside of the State as required in sections 51.308(d)(1) through (4).

Best Available Retrofit Technology (BART)

We agree with Utah's determination of sources subject to BART and that the SO_2 milestones and backstop trading program address BART for SO_2.

However, as we commented in 2008, we believe that Utah is required to evaluate the five BART factors for feasible control alternatives for NO_x and PM emissions. We do not agree with Utah that it is sufficient to demonstrate that the controls for Hunter Units 1 and 2 and Huntington Units 1 and 2 are better than the presumptive levels established by EPA in its 2005 BART rulemaking, since EPA's costs were based on industry averages. Considering the number of Class I areas that could benefit from emissions controls at these specific sources, emissions limits lower than those presumed by EPA may be cost effective. Other western states have performed source-specific analyses and determined BART controls for NO_x that are more stringent than the EPA's 2005 presumptive levels. We request that Utah provide an analysis of the costs and visibility benefits for a full array of NO_x control technologies for the Hunter and Huntington power plants.

Long-Term Strategy for NO_x and PM from Stationary Sources

In our 2008 comments, we requested that DAQ consider the impacts of Utah's emissions on visibility at Class I areas outside of Utah. For Class I areas not on the Colorado Plateau, Section 51.308(d)(1) through (4) are applicable and require demonstration of emissions reductions needed to meet the reasonable progress goals for these Class I areas.

We commend the addition of the source apportionment results from the Western Regional Air Partnership (WRAP) in Figures 17-19 to demonstrate that Utah's contribution to nitrate (NO_3) at Class I areas within and outside Utah is projected to decrease by 2018. It would be helpful to add an emissions table before the WRAP source apportionment modeling results to illustrate the emissions assumptions[1] used in the WRAP source apportionment modeling. The preliminary WRAP 2018 inventory included emissions reductions expected from mobile sources, but did not include the emissions reductions due to BART controls as reported in the Utah SIP. Adding the emissions table before the WRAP source apportionment results in Figures 17-19 would explain why the impact from Utah due to mobile sources is projected to decrease by 2018, but the contributions from point sources are not shown to decrease. Later WRAP inventories do include expected BART controls but the source apportionment modeling was not updated to reflect these controls.

Utah's long term strategy needs to address whether additional emissions controls for stationary sources, beyond those considered for BART, are appropriate to provide for reasonable progress at Class I areas outside the Colorado Plateau. Our review of the WRAP emissions inventory data[2] indicated that the major stationary sources of NO_x in Utah are the two BART sources, plus Hunter Unit 3, Carbon Units 1 & 2, and Intermountain Generation Station. Consideration of the WRAP four-factor analysis for reasonable progress[3] would provide general control alternatives for these sources.

In Table 21, the labels for VOC and CM are missing.

WRAP Responsibilities within the SIP

On pages 108 and 117, we recommend that you delete the commitment to the final WRAP 2018 inventory and modeling as there is no funding to meet this expectation.

In many places the SIP references work that the WRAP will provide to implement the SIP, such as tracking and reporting on emissions for SO_2, administering the backstop trading program, and other functions. The SIP acknowledges that Utah will assume responsibility for many of these functions should the WRAP not be able to provide these services. We request to be consulted at the time when Utah assumes any responsibilities assigned to WRAP in the SIP.

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[1] http://vista.cira.colostate.edu/tss/Results/HazePlanning.aspx
[2] http://www.wrapair.org/forums/ssjf/pivot.html
[3] http://www.wrapair.org/forums/iwg/docs.html

NPS' General Comments on PacifiCorp's Hunter and Huntington Power Plants
March 4, 2011

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 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 the San Juan Generating Station, 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.[1] EPA has proposed SCR at the Four Corners Power Plant at $2,600 - $2,900/ton, and at the San Juan Generating Station at $5,900 - $7,400/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[2] 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,[3] 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.)

Cost Estimation Methods

The cost estimates submitted by UT DEQ/PacifiCorp are lacking in the types of specific information needed to give them credibility. Although there are several methods for estimating costs, our experience leads us to believe that no one method is perfect and that the costing methods need to be tempered by real-world data. However, we found no documented actual vendor quotes in the materials made available for our review. In that case, the BART Guidelines recommend use of the OAQPS Control Cost Manual (CCM):

> 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

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[1] "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

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

[3] 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."

> 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.

Our contention that the CCM should be the primary source 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.

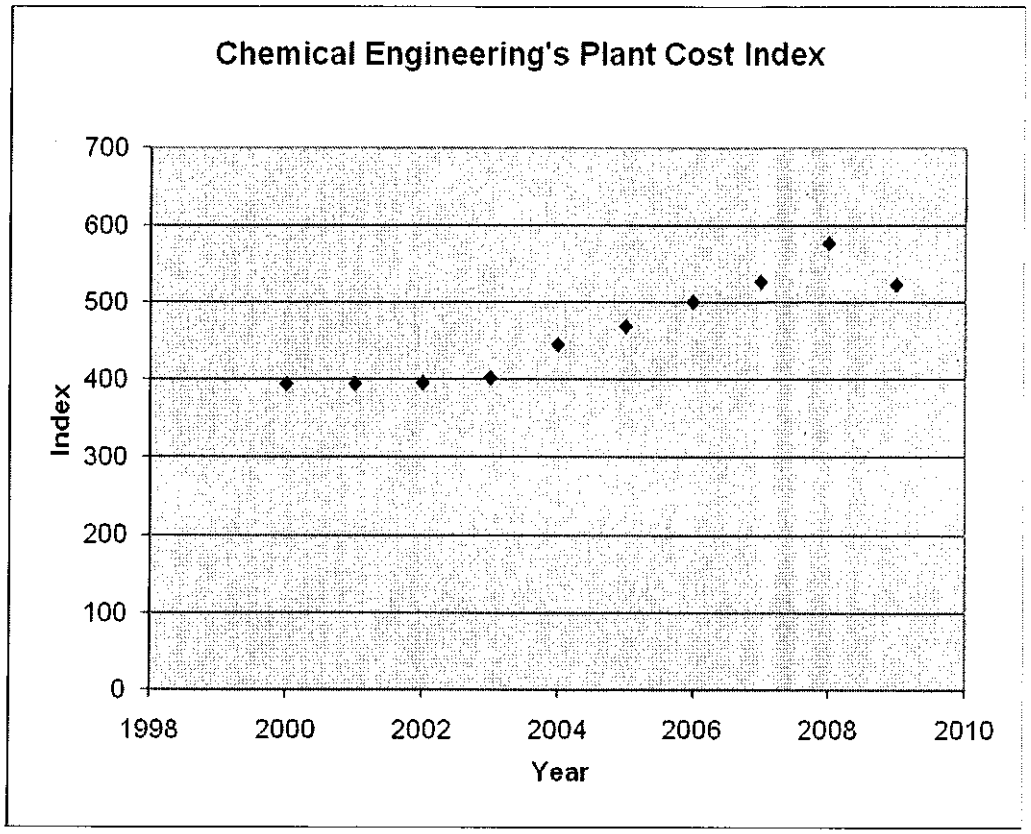
Inflation and the Allowance for Funds During Construction:

Larry Sorrels, an economist at EPA's Office of Air Quality Planning and Standards (OAQPS) provided[4] insight on matters pertaining to inflation and the Allowance for Funds During Construction (AFUDC):

> On cost indexes, I prefer the CEPCI (Chemical Engineering Plant Cost Index) 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.
>
> 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.

[4] 7/21/10 e-mail to Don Shepherd

The CEPCI is shown in the chart (below) prepared by Aaron Worstell of EPA R8.



Visibility Improvement Metrics

UT DEQ did not consider visibility improvements as required by the BART Guidelines. 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. And, it does not make sense to evaluate impacts at one Class I area, while ignoring others that are similarly significantly impaired. It follows that, if emission from the BART source are reduced, the benefits will be spread well beyond only the most impacted Class I area, and this must be accounted for.[5]

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

[5] 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 and the Four Corners Power Plant. EPA also calculated cumulative benefits in its demonstration that CAIR was better than BART.

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. 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.

NPS BART Analysis

The keys to UT DEQ's BART proposal appear to reside in this statement: "PacifiCorp's calculations of costs associated with SCR are much higher than what is shown in (the table on page six of the 1/03/11 letter to EPA). PacifiCorp estimated that the costs would be $4,500 - $5,000 per ton removed," and UT DEQ's assertion that meeting presumptive BART limits is sufficient and that any additional analysis is "voluntary."

UT DEQ/PacifiCorp have proposed that the NO_X emissions limitation of 0.26 lb/mmBtu on a 30-day rolling average is BART for Hunter Units 1 and 2. The emission limits are to be achieved with combustion controls.

Step 3 - Evaluate Control Effectiveness

UT DEQ has underestimated the effectiveness of SCR. A significant reason for the higher cost-effectiveness of this option estimated by UT DEQ is the low NO_x control efficiency it assumed for a technology that should be able to achieve 90% control. UT DEQ estimates that addition of SCR can reduce NO_x by 77% to 0.06 lb/mmBtu on an annual basis. (PacifiCorp estimated SCR effectiveness at 73% at 0.07 lb/mmBtu.)

SCR is different from many other control technologies in that its efficiency is not highly dependent upon the concentration of the pollutant to be controlled.[6] Instead, SCR efficiency is primarily influenced by the design of the catalyst reactor, that is, the volume of the catalyst, its cross-sectional area, number of layers, and measures to prevent blinding and deactivation, as well as replacement schedule. If it is necessary to achieve a high degree of removal efficiency on an inlet stream with a low concentration, more catalyst can be included in the design. It is generally understood that NO_X reductions of

[6] However, as noted below in an excerpt from the EPA Control Cost manual, at very low inlet concentrations, removal efficiency may be lower:

> In general, higher uncontrolled NOx inlet concentrations result in higher NOx removal efficiencies due to reaction kinetics. However, NOx levels higher than approximately 150 parts per million (ppm), generally do not result in increased performance. Low NOx inlet levels result in decreased NOx removal efficiencies because the reaction rates are slower, particularly in the last layer of catalyst.

approximately 90% or more may be achieved with SCR systems.[7] 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%..."

We are aware of vendor guarantees of 0.05 lb/mmBtu,[8] and understand that major vendors are designing SCR systems to achieve 0.02 lb/mmBtu[9] on coal-fired boilers.

Operational evidence from SCR retrofits on eastern EGUs (see Appendix A for "EGUs less than 0.06 lb/mmBtu in 2010") clearly indicates that SCR can achieve 0.05 lb/mmBtu or lower on an annual basis. For example, we found seven tangentially-fired boilers operating at or below 0.05 lb/mmBtu in 2010. We conclude that SCR can achieve 0.05 lb/mmBtu on an annual basis.

It is generally assumed that SCR can achieve at least 90% NO_X reduction,[10] and we have presented evidence demonstrating that SCR can achieve 0.05 lb/mmBtu (or lower) on similar tangentially-fired boilers.[11] For example, Salt River Project (SRP) assumed that addition of SCR to the tangentially-fired boilers at Navajo Generating Station[12] could achieve 0.05 lb/mmBtu on an annual basis.[13] The combination of the real-world examples we have previously presented plus the assumptions by Tri-State and SRP should provide sufficient weight-of-evidence for EPA to conclude that SCR can reasonably be expected to achieve 0.05 lb/mmBtu (or better) on an annual basis.

UT DEQ has indicated that SCR would result in 4,700 – 5,100 additional tons of NO_x removal. (PacifiCorp estimated 3,558 tpy removed.) If we recognize that SCR can reduce NO_X to 0.05 lb/mmBtu (or less) on an annual basis, true utilization of SCR would remove 3,800 tpy.

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[7] 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."

[8] Minnesota Power Taconite Harbor BART analysis.

[9] Babcock & Wilcox presentation to Minnesota Pollution Control Agency.

[10] J.E. Chichanowicz Report Current Capital Cost and Cost Effectiveness - January 2010 (attached)

[11] While we have focused our discussion on tangentially-fired EGUs, because of their inherently lower NO_X emissions, it is likely that SCR could achieve lower NO_X emissions than other EGUs. Therefore, one could also consider that there are another 19 EGUs that were also achieving NO_X of 0.05 lb/mmBtu or lower in 2010. If we consider SCR proposals for wall-fired RGUs, we now include the assumed 0.05 lb/mmBtu limits that were evaluated by Tri-State generation for the Craig power plant in CO and the San Juan Generating Station in NM for which EPA R-6 has proposed SCR at 0.05 lb/mmBtu on a 30-day rolling average basis.

[12] Navajo_Report_SCR_and_BH_Cost_Est_Rev_D (electronic file attached in Appendix B.)

[13] SRP recently proposed addition of SCR by 2030 under the Reasonable Progress provisions of the Regional Haze Rule.

Step 4 - Evaluate Impacts and Document Results

PacifiCorp has overestimated the cost of SCR. EPA guidance states, "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). In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible." Instead, PacifiCorp relied upon an unknown method to generate its cost estimates. PacifiCorp included some very questionable and unsupported assumptions in its capital cost estimates. For example, PacifiCorp included $14 million if AFUDC which is typically not allowed by EPA. As a result, the Total Capital Investment estimated by PacifiCorp is 224% of the Direct Capital cost as opposed to the 141% values used by the EPA Control Cost Manual, as discussed later.

Although there are several methods for estimating SCR costs, our experience leads us to believe that no one method is perfect and that the costing methods need to be tempered by real-world data. An excellent example of a SCR retrofit cost analysis was prepared for the Navajo Generating Station (NGS) and is being provided separately (in Appendix B. "SCR Costs"). The NGS analysis contains the type of vendor estimates and detailed engineering analyses recommended by the BART Guidelines and 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 CCM.

"Real-World" SCR Capital Costs

Real-world, utility industry-generated evidence of SCR costs can 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 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..."

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[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/

"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.

The first study evaluated the installed costs of more than 20 SCR retrofits from 1999 to 2001. The installed capital cost ranged from $106 to $213/kW, converted to 2007 dollars.[15] Costs are escalated through using the CEPCI.
The second survey of 40 installations at 24 stations reported a cost range of $76 to $242/kW, converted to 2007 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 $118/kW to $261/kW, converted to 2007 dollars.[17]

A fourth study, presented in a course at PowerGen 2005, reported an upper bound range of $180/kW to $202/kW, converted to 2007 dollars.[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's Region 8 Office has compiled a graphic presentation of SCR capital costs adjusted to 2009 dollars—please see Appendix B for "SCR Capital Costs and References". The EPA data confirm that SCR capital costs typically range from $73 – $243/kW.

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

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

[17] M. Marano, Estimating SCR Installation Costs, Power, January/February 2006. Ex. 5. The reported range of $100 - $221/kW was converted to 2008 dollars ($130 - $286/kW) using the ratio of CEPCI for 2008 to 2004: 575.4/444, 2.
http://findarticles.com/p/articles/mi_qa5392/is_200602/ai_n21409717/print?tag=artBody;col1

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

[19] 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).

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 $205/kW.[20] It should also be noted that the Boswell Unit 3 retrofit was designed to meet 0.05 lb/mmBtu. 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)."

Thus, the overall range for these industry studies is $50/kW to $300/kW. The upper end of this range is for highly complex retrofits with severe space constraints, such as Belews Creek, reported to cost $265/kW,[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] only cost $251/kW in 2007 dollars.[23]

EPA Control Cost Manual

We have been working with an Excel workbook we derived from the SCR cost estimation method presented by EPA's Office of Air Quality Planning and Standards CCM. Based upon the industry data cited above, we now believe that the CCM method tends to underestimate the Direct Capital Cost (DCC) component of the SCR cost estimate. Because the Total Capital Investment (TCI) component is directly proportional to the DCC in the CCM method, a straightforward application of the CCM method usually results in TCI costs lower than what we would expect from the real-world industry data presented above. Therefore, we have been developing a way to modify the CCM method to provide TCI estimates more consistent with industry data. First, we adjust the DCC from the CCM's 1998 baseline to current (2009) cost using the Chemical Engineering Plant Cost Index (CEPCI ratio = 1.34) to adjust costs for inflation. **(Please see the individual source analyses in Appendix B. "NPS SCR modified Cost Manual approach for Hunter #1" (and #2)** for specific details of how we apply this method.) In this case, the CCM method yields $76/kW (Please see the "ICC" tab cell L18.), which appears too low for EGUs this size and thus prompted us to over-ride the CCM's TCI calculation.

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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, Ex. 7. 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, 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) (608.8/395.6) = $275.5/kW. http://www.mcilvainecompany.com/sampleupdates/NoxMarketUpdateSample.htm

The CCM assumes that the TCI for SCR will be 141% (cell M17) of the DCC (cell L4), and that the costs that comprise the TCI will also be ratios of the DCC. PacifiCorp estimated the DCC at $69 million and the TCI for each EGU at $155 million (or $323/kW. Because the PacifiCorp TCI estimate of $323/kW exceeds the range of expected values for EGUs of this size, it will not be used for further estimates. Instead, the PacifiCorp DCC is multiplied by 141% (per the CCM) and the resulting $203/kW (which is within the range of reasonable costs for an EGU of this size) is fed back to cell C7 of the "Given/Assume" tab and to cell F5 on the "Ann Cost" tab.

Annual SCR Costs

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 CCM for estimating DAC appear to be straight-forward and should accurately represent annual costs with no need for adjustment.

NPS' Specific Comments on PacifiCorp's Huntington Power Plant
March 4, 2011

PacifiCorp's Huntington Power Plant (Huntington) consists of two units with a total plant electrical output rating of 944 megawatts (MW). According to EPA's Clean Air Markets (CAM) Database, in 2010, Huntington ranked #64 (of 1,236 facilities) in the US for nitrogen oxides (NO_x) emissions at 8,283 tons.[1] Unit 1 (498 MW gross) and Unit 2 (446 MW gross) are dry-bottom, tangentially-fired. Units 1 and 2, the only BART-eligible units, each have a maximum rated heat input capacity of 4,960 mmBtu/hr. Bituminous coal is the primary fuel for both power boilers.

The air pollution control equipment for Unit 1 consists of an electrostatic precipitator (ESP), and first-generation Low-NO_X Burners + Close-Coupled Overfire Air (LNB+ (CCOFA) installed in 1997, and a wet limestone scrubber installed prior to 2000.

The air pollution control equipment for Unit 2 consists of a baghouse installed 11/18/2006 to replace an ESP, and Low-NO_X Burners + Separated Overfire Air (LNB+ SOFA) installed 11/18/2006 to replace the old CCOFA, and a wet limestone scrubber installed 11/18/2006.

These changes to Units 1 and 2 were expected to allow Huntington to achieve a NO_X emission rate of 0.26 lb/mmBtu. However, data from EPA's CAM database for 2009 – 2010 show annual NO_X emissions at 0.34 - 0.36 lb/mmBtu for Unit 1 and 0.22 lb/mmBtu for Unit 2.

Information provided by the Utah Department of Environmental Quality (UT DEQ) estimates that Huntington Units #1 & #2 caused 19.1 deci-Views (dV) of visibility impairment in the eight Class I areas within 300 km, with the maximum impairment of 4.4 dv at Capitol Reef National Park.

(Please see our general comments.) We applied the procedures in Section 4, Chapter 2 of the Cost Manual to the Huntington boilers.[2] Because modern SCR systems are typically designed to achieve 90+% NO_x reductions, we used 0.05 lb/mmBtu as our target. The columns labeled "CCM estimates" are derived directly from a straightforward application of the CCM. The "NPS estimates" use the PacifiCorp DCC estimates as the basis for the subsequent annual cost calculations.

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[1] Of 3,581 units, Hunteington Unit 1 ranked #76 at 4,574 tons and Hunteington Unit 2 ranked #127 at 3,709 tons.

[2] Our calculations are contained in the attached Excel workbook in Appendix B.

SCR Cost-benefit Analysis	Unit #1			Unit #2		
	CCM estimates	NPS estimates	Company estimates	CCM estimates	NPS estimates	Company estimates
Emissions Reduction (tpy)	3,916	3,916	3,715	4,030	4,030	3,715
Capital Cost	$ 37,677,385	$108,903,141	$167,111,482	$ 37,677,385	$ 108,903,141	$ 167,111,482
Capital Cost ($/kW)	$ 85	$ 245	$ 376	$ 84	$ 242	$ 371
O&M Cost	$ 2,379,035	$ 3,447,421	$2,280,012	$ 2,417,980	$ 3,486,366	$2,280,012
Annualized Cost	$ 5,935,513	$ 13,727,107	$19,933,770	$ 5,974,458	$ 13,766,052	$19,933,770
Cost-Effectiveness ($/ton)	$ 1,516	$ 3,506	$5,366	$ 1,483	$ 3,416	$5,366

We estimated a Total Annual Cost of $13.8 million for Huntington Units 1 & 2, and produced cost-effectiveness estimates of $3,400 - $3,500/ton.

We believe that our cost estimates, based upon application of the EPA BART Guidelines/CCM and real-world industry data, as well as a very conservative assumption that SCR will reduce NO_X by only 81% down to 0.05 lb/mmBtu, are more "transparent" and more realistic than those presented by PacifiCorp and warrant selection of SCR by UT DEQ.

Step 5 - Evaluate Visibility Impacts

UT DEQ provided "Table 1. Post-Control BART Modeling, 98th Percentile 3-year average deciviews" in its draft SIP which we commented upon in our 8/01/08 letter and which was subsequently approved by the UT Air Quality Board. It was not until we saw the most recent version of the SIP that we learned that Table 7 was incorrect and had been deleted from the latest draft. This poses two significant procedural problems:

- The information on which our previous comments were based (and upon which the Air Quality Board acted) was substantially incorrect.
- There is no valid analysis provided of the visibility impacts of the BART alternatives.

Conclusions & Recommendations

- The BART limits proposed by UT DEQ will allow Huntington to continue to cause visibility impairment at eight Class I areas.
- PacifiCorp has underestimated the ability of SCR to reduce NO_X emissions and overestimated its costs.
- UT DEQ failed to properly evaluate the visibility impacts of the feasible BART alternatives.
- We believe that a proper five-factor analysis would conclude that SCR at 0.05 lb/mmBtu is BART for Huntington Units 1 & 2.

NPS' Specific Comments on PacifiCorp's Hunter Power Plant
March 4, 2011

PacifiCorp's Hunter Power Plant (Hunter) consists of three units with a total plant electrical output rating of 1,455 megawatts (MW). According to EPA's Clean Air Markets (CAM) Database, in 2010, Hunter ranked #13 (of 1,236 facilities) in the US for nitrogen oxides (NO_x) emissions at 16,205 tons.[1] Unit 1 (488 MW gross operational in 1978) and Unit 2 (488 MW gross operational in 1980) are dry-bottom, tangentially-fired. Units 1 and 2, the only BART-eligible units, each have a maximum rated heat input capacity of 4,750 mmBtu/hr. Bituminous coal is the primary fuel for all three power boilers.

The air pollution control equipment for Units 1 and 2 consists primarily of electrostatic precipitators (ESPs) to control particulate (PM) emissions. In 1997 - 1999 PacifiCorp installed first-generation Low-NO_X Burners (LNB), and in 2005 began installation of wet limestone scrubbers and Close-Coupled Overfire Air (CCOFA on units #1 & #2) to reduce NO_X emissions from Units 1 & 2. These changes to Units 1 and 2 were expected to allow Hunter to achieve a NO_X emission rate of 0.26 lb/mmBtu. However, data from EPA's CAM database for 2009 – 2010 show annual NO_X emissions at 0.34 - 0.35 lb/mmBtu for units 1 & 2.

Information provided by the Utah Department of Environmental Quality (UT DEQ) estimates that Hunter Units #1 & #2 caused 15.8 deci-Views (dV) of visibility impairment in the eight Class I areas within 300 km, with the maximum impairment of 4.1 dv at Capitol Reef National Park.

(Please see our general comments.) We applied the procedures in Section 4, Chapter 2 of the Control Cost Manual (CCM) to the Hunter boilers.[2] Because modern SCR systems are typically designed to achieve 90+% NO_x reductions, we used 0.05 lb/mmBtu as our target. The columns labeled "CCM estimates" are derived directly from a straightforward application of the CCM. The "NPS estimates" use the PacifiCorp DCC estimates as the basis for the subsequent annual cost calculations.

SCR Cost-benefit Analysis	Unit #1			Unit #2		
	CCM estimates	NPS estimates	Company estimates	CCM estimates	NPS estimates	Company estimates
Emissions Reduction (tpy)	3,794	3,794	3,558	3,859	3,859	3,558
Capital Cost	$ 36,505,512	$ 97,633,386	$ 155,049,000	$ 36,505,512	$ 97,633,386	$ 155,049,000
Capital Cost ($/kW)	$ 76	$ 203	$ 323	$ 76	$ 203	$ 323
O&M Cost	$ 2,299,577	$ 3,216,495	$ 2,280,012	$ 2,321,708	$ 3,238,626	$ 2,280,012
Annualized Cost	$ 5,745,439	$ 12,432,396	$ 157,332,893	$ 5,767,570	$ 12,454,527	$ 157,332,893
Cost-Effectiveness ($/ton)	$ 1,515	$ 3,277	$ 5,271	$ 1,495	$ 3,228	$ 5,271

[1] Of 3,581 units, Hunter Unit 1 ranked #64 at 4,971 tons, Hunter Unit 2 ranked #50 at 5,436 tons, and Hunter Unit 3 ranked #41 at 5,799 tons.
[2] Our calculations are contained in the attached Excel workbook in Appendix B.

We estimated a Total Annual Cost of $12.4 million for Hunter Units 1 & 2, and produced cost-effectiveness estimates of $3,300/ton.

We believe that our cost estimates, based upon application of the EPA BART Guidelines/CCM and real-world industry data, as well as a very conservative assumption that SCR will reduce NO_X by only 81% down to 0.05 lb/mmBtu, are more "transparent" and more realistic than those presented by PacifiCorp and warrant selection of SCR by UT DEQ.

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- UT DEQ failed to properly evaluate the visibility impacts of the feasible BART alternatives.
- We believe that a proper five-factor analysis would conclude that SCR at 0.05 lb/mmBtu is BART for Hunter Units 1 & 2.