

**NPS General BART Comments on ADEQ BART Analyses**  
**November 29, 2010**

As with any new program, much has been learned, and much is left to learn by all parties involved, and we are pleased to share the information we have obtained from our reviews of BART proposals across the nation. Following are our general comments on the five-step BART analyses conducted by ADEQ.

Step 1: “Identify All Available Technologies” and Step 2: “Eliminate Technically Infeasible Options” were generally comprehensive and well supported.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

**Effectiveness of Selective Catalytic Reduction (SCR)**

A common problem was an underestimation of the effectiveness of SCR to reduce emissions. 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.<sup>1</sup> 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<sub>x</sub> reductions of approximately 90% or more may be achieved with SCR systems.<sup>2</sup> And, according to the June 13, 2009 “Power” magazine article “Air Quality Compliance: Latest Costs for SO<sub>2</sub> and NO<sub>x</sub> 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<sub>x</sub> by 90%...”

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<sup>1</sup> ADEQ has included this statement taken from the company BART analysis:

SCR can achieve NO<sub>x</sub> control efficiencies as high as 90% with inlet concentrations in the range of 300 to 400 ppmvd. If inlet NO<sub>x</sub> concentrations are less than 250 ppmvd, SCR can achieve NO<sub>x</sub> control efficiencies ranging from 70% to 80%.

This assertion is contrary to our understanding of SCR performance factors. We suspect that ADEQ may have misunderstood because SCRs on lower concentration gas streams may have been designed to achieve lower removal efficiencies. Our understanding is that SCR performance is primarily a function of catalyst temperature, volume, type, and area. 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 NO<sub>x</sub> inlet concentrations result in higher NO<sub>x</sub> removal efficiencies due to reaction kinetics. However, NO<sub>x</sub> levels higher than approximately 150 parts per million (ppm), generally do not result in increased performance. Low NO<sub>x</sub> inlet levels result in decreased NO<sub>x</sub> removal efficiencies because the reaction rates are slower, particularly in the last layer of catalyst.

We request that ADEQ provide support for its contention.

<sup>2</sup> According to the Institute of Clean Air Companies white paper titled “Selective Catalytic Reduction (SCR) Control of NO<sub>x</sub> Emissions from Fossil Fuel-Fired Electric Power Plants” (published in May 2009), “By proper catalyst selection and system design, NO<sub>x</sub> removal efficiencies exceeding 90 percent may be achieved.”

We are aware of vendor guarantees of 0.05 lb/mmBtu,<sup>3</sup> and understand that major vendors are designing SCR systems to achieve 0.02 lb/mmBtu<sup>4</sup> on coal-fired boilers.

Operational evidence from SCR retrofits on eastern EGUs (see Appendix EGUs less than 0.06 lb/mmBtu in 2009) clearly indicates that SCR can achieve 0.05 lb/mmBtu or lower on an annual basis. For example, we found 12 tangentially-fired boilers operating at or below 0.05 lb/mmBtu in 2009.

ADEQ has assumed that 24-hour and 30-day rolling average SCR emissions would be the same as the corresponding annual average emission rate. However, we looked at monthly data for 28 EGUs with SCR's operating at or below 0.05 lb/mmBtu on an annual average (see Appendix 2009 monthly emissions) and found that, of the 228 months of data, 214 were at or below 0.06 lb/mmBtu. For tangentially-fired EGUs, we found that 84 of 89 were at or below 0.06 lb/mmBtu. We conclude that SCR can achieve 0.05 lb/mmBtu on an annual basis and 0.06 lb/mmBtu on a 30-day rolling average basis.

#### Step 4: Evaluate Impacts and Document Results

##### Non-Air Quality Environmental Impacts

*ADEQ:* SNCR and SCR installation could impact the salability and disposal of fly ash due to ammonia levels. Other environmental impacts involve the potential public and employee safety hazard associated with the storage of ammonia, especially anhydrous ammonia, and the transportation of the ammonia to the power plant site.

*NPS:* According to the Institute for Clean Air Companies, ammonia can be handled safely.<sup>5</sup> Our discussions with SNCR vendors indicate that the concern about ash salability is likely unfounded.

##### Cost of Compliance

###### **SCR Costs**

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

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<sup>3</sup> Minnesota Power Taconite Harbor BART analysis.

<sup>4</sup> Babcock & Wilcox presentation to Minnesota Pollution Control Agency.

<sup>5</sup> "Concern over the handling of ammonia was initially raised as a problem with SCR technology applications due to the transportation and storage of a hazardous gas under pressure. However, large quantities of ammonia already are used for a variety of applications with an excellent overall safety record. (In 2006, 17 billion pounds of ammonia were produced in the U.S.) These applications include the manufacture of fertilizers and a variety of other chemicals, as well as refrigeration. With the proper controls, ammonia use is safe and routine." WHITE PAPER SELECTIVE CATALYTIC REDUCTION (SCR) CONTROL OF NO<sub>x</sub> EMISSIONS FROM FOSSIL FUEL-FIRED ELECTRIC POWER PLANTS PREPARED BY: NO<sub>x</sub> CONTROL TECHNICAL DIVISION INSTITUTE OF CLEAN AIR COMPANIES, INC. May 2009 Copyright

data. Both OAQPS and EPA Region 8 have advised against the use of CUECost. Instead, the BART Guidelines recommend use of the OAQPS Control Cost Manual:

The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source (such as the OAQPS Control Cost Manual, Fifth Edition, February 1996, 453/B-96-001). In order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual, where possible. The Control Cost Manual addresses most control technologies in sufficient detail for a BART analysis. The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option.

EPA's belief that the Control Cost Manual should be preferred over CUECost for developing cost analyses that are transparent and consistent across the nation and provide a common means for assessing costs is further supported by this November 7, 2007, statement from EPA Region 8 to the North Dakota Department of Health:

The SO<sub>2</sub> and PM cost analyses were completed using the CUECost model. According to the BART Guidelines, in order to maintain and improve consistency, cost estimates should be based on the OAQPS Control Cost Manual. Therefore, these analyses should be revised to adhere to the Cost Manual methodology.

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

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

## **Cost Escalation**

Mr. Sorrels also commented<sup>6</sup> upon PSCo's use of Present Value of Revenue Requirements (PVRR) model to calculate the levelized cost of each technology.

The PVRR model really can't be complementary to the EPA air pollution control cost methodology. The PVRR model is designed to generate nominal, levelized costs that incorporate a return to the equity and debt incurred by the utility that purchases the control equipment. The EPA air pollution control cost methodology generates real (inflation-adjusted), equivalent annual costs over the life of control equipment without consideration of return on equity or debt. Any presentation of PVRR results should state clearly that the pollution control investment is treated just like any other capital investment for a regulated entity - the utility still receives its expected rate of return on its investment and really loses no profit as a result of installation and operation of this NO<sub>x</sub> control equipment.

This would not be the case for any non-regulated utility or non-utility firm.

The discount rate of 7.88% is a nominal rate, not a real one (consistent with the comment I made above).

Estimating real annual costs means no use of escalation factors, something that is utilized in the PVRR model.

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<sup>6</sup> E-mail dated September 7, 2010 to Don Shepherd of NPS.

There needs to be more detail on what the capital and O&M estimation methodologies include. There are some allusions to what is contained in these estimates as prepared by GAAR, but no detail. I suppose this detail is in the reports that Xcel will send to the State of Colorado at their request.

In summation, it is not appropriate to use the CUECost model, nor is it appropriate to escalate costs into the future and compare them against current cost thresholds.

Mr. Sorrels also provided<sup>7</sup> insight on matters pertaining to **inflation** and the **Allowance for Funds During Construction (AFUDC)**:

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

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.

Evidence that ADEQ has overestimated its SCR costs can be found in a June 2009 article in "Power" magazine.<sup>8</sup>

"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<sub>x</sub> 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..."

"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 generally lower than estimated by ADEQ.

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.<sup>9</sup> Costs are escalated through using the CEPCI.

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<sup>7</sup> 7/21/10 e-mail to Don Shepherd

<sup>8</sup> June 13, 2009 "Power" magazine article "Air Quality Compliance: Latest Costs for SO<sub>2</sub> and NO<sub>x</sub> 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 second survey of 40 installations at 24 stations reported a cost range of \$76 to \$242/kW, converted to 2007 dollars.<sup>10</sup>

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.<sup>11</sup>

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.<sup>12</sup>

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.<sup>13</sup>

EPA's Region 8 Office has compiled a graphic presentation of SCR capital costs adjusted to 2009 dollars—please see **Appendix**. The EPA data confirm that SCR capital costs range from \$73 – \$243/kW.

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,<sup>14</sup> 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,<sup>15</sup> only cost \$251/kW in 2007 dollars.<sup>16</sup>

We have been working with an Excel workbook we derived from the SCR cost estimation

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<sup>9</sup> 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.

<sup>10</sup> 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.

<sup>11</sup> 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](http://findarticles.com/p/articles/mi_qa5392/is_200602/ai_n21409717/print?tag=artBody;col1)

<sup>12</sup> 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).

<sup>13</sup> 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).

<sup>14</sup> Steve Blankinship, SCR = Supremely Complex Retrofit, Power Engineering, November 2002, Ex. 7. The unit cost:  $(\$325,000,000/1,120,000 \text{ kW})(608.8/395.6) = \$290/\text{kW}$ . [http://pepei.pennnet.com/display\\_article/162367/6/ARTCL/none/none/1/SCR---Supremely-Complex-Retrofit/](http://pepei.pennnet.com/display_article/162367/6/ARTCL/none/none/1/SCR---Supremely-Complex-Retrofit/)

<sup>15</sup> Standing on the Shoulder of Giants, Modern Power Systems, July 2002, Ex. 8.

<sup>16</sup> 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  $(\$179/\text{kW})(608.8/395.6) = \$275.5/\text{kW}$ . <http://www.mcilvainecompany.com/sampleupdates/NoxMarketUpdateSample.htm>

method presented by EPA's Office of Air Quality Planning and Standards Control Cost Manual (Cost Manual). We now believe that the Cost Manual 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, a straightforward application of the Cost Manual usually results in TCI costs lower than what we would expect from the real-world industry data presented above, we have been trying to find a way to modify the Cost Manual method to provide TCI estimates more consistent with industry data. First, we adjust the DCC from the 1998 baseline to current cost using the Chemical Engineering Plant Cost Index (CEPCI) to adjust costs for inflation using the CEPCI. Our current approach is to use the DCC presented by the source and apply the Cost Manual ratios for Indirect Installation and Contingency costs to the DCC to estimate TCI. If the resulting TCI, expressed in \$/kW is within the expected range, we carry that estimate through the remainder of the cost estimation process. If this TCI estimate is outside the expected range, we can override the TCI calculation by inserting our best estimate based upon the size of the EGU and the degree of retrofit difficulty.

The Direct Annual Cost (DAC) component of the process is also important because it represents a significant portion of the Total Annual Cost. The methods presented by the Cost Manual for estimating DAC appear to be straight-forward and should accurately represent annual costs with no need for adjustment. However, we note in our review of the BART analyses resented by the sources that there appears to be a consistent significant overestimation of DAC.

#### Step 5: Evaluate Visibility Results

We 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. If we look at only the most-impacted Class I area, we ignore that the other Class I areas are all suffering from impairment to visibility "caused" by the BART source. 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.<sup>17</sup>

The BART Guidelines represent an attempt to create a workable approach to estimating visibility impairment. As such, they require several assumptions, simplifications, and shortcuts about when visibility is impaired in a Class I area, and how much impairment is occurring. The Guidelines do not attempt to address the geographic extent of the impairment, but assume that all Class I areas are created equal, and that there is no difference between widespread impacts in a large Class I area and isolated impacts in a small Class I area. To address the problem of geographic extent, we have been looking at the cumulative impacts of a source on all Class I areas affected, as well as the cumulative benefits from reducing emissions. While there are certainly more sophisticated approaches to this problem, we believe that this is the most practical, especially when considering the modeling techniques and information available.

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<sup>17</sup> 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.

## Step 6: Select BART Control

### **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, and Wisconsin is using \$7,000 - \$10,000/ton as its BART threshold.<sup>18</sup>

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<sup>19</sup> 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,**<sup>20</sup> with a maximum of \$51 million per dv proposed by South Dakota at the Big Stone power plant. We note that OR DEQ has chosen \$10 million/dv as a cost criterion, which is somewhat below the national average.

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<sup>18</sup> “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

<sup>19</sup> <http://www.wrapair.org/forums/ssjf/bart.html>

<sup>20</sup> 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.”