

**NPS Comments on Best Available Retrofit Technology (BART) Analysis of Control Options  
For Tri-State Generation & Transmission Association, Inc. – Craig Station Units 1 & 2  
December 1, 2010**

**Process Description**

The Tri-State Generation & Transmission Association, Inc. (Tri-State) Craig Station 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. Units 1 and 2, rated at 4,318 mmBtu/hour each (net 428 MW), were placed in service in 1980, and 1979, respectively. Of 1,228 plants, EPA Clean Air Markets (CAM) data for 2008 rank the Craig facility #304 for SO<sub>2</sub> and #43 for NO<sub>x</sub>. Unit 3 started up in 1984 and is not BART-eligible. We will address controls for Unit 3 separately under a reasonable progress analysis.

**Units 1 and 2**

Units 1 and 2 are similar 428 MW coal-fired steam electric generating units equipped with dry-bottom wall-fired coal boilers. Construction of Units 1 and 2 began in 1974; Unit 1 began operation in 1980 and Unit 2 began operation in 1979. These units are equipped with fabric filter (baghouse) systems for controlling particulate matter (PM) emissions, and wet limestone Flue Gas Desulfurization (FGD) systems for the control of sulfur dioxide (SO<sub>2</sub>) emissions. The boilers are equipped with ultra-low nitrogen oxide (NO<sub>x</sub>) dual register burners with overfire air for minimization of NO<sub>x</sub> emissions. The FGD and Ultra Low-NO<sub>x</sub> Burner (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 3,558 EGUs, 2008 CAM data rank Units 1 and 2 at #910 and #883, respectively for SO<sub>2</sub>, and #170 and #147, respectively for NO<sub>x</sub>. CDPHE modeling data show that Craig Units 1 and 2 each have a maximum impact at Mt. Zirkel Wilderness Area of 3.73 dv. The cumulative impacts of each of Craig Units 1 and 2 across the eleven Class I areas modeled is greater than 10 dv, which ranks these units among the highest<sup>1</sup> of any facility we have evaluated under the BART program.

**NO<sub>x</sub> BART Analysis**

**Step 1: Identify All Available Retrofit Control Options**

*CDPHE*: TriState identified several options for NO<sub>x</sub> control:

- New/modified Low NO<sub>x</sub> Burners (LNBS) with Overfire Air (OFA) system (next generation)
- Advanced OFA system or Rotating overfire Air (ROFA)
- Neural network system combustion controls

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<sup>1</sup> The highest are Cholla Generating Station, Coronado Generating Station, Four Corners Power Plant, Navajo Generating Station, Centralia, PGE Boardman, San Juan Generating Station.

- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)

The Division also identified and examined the following additional control options for these units:

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Coal reburn +SNCR

Step 2: Eliminate All Technically Infeasible Control Options

- Advanced OFA system or Rotating overfire Air (ROFA)
- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Coal reburn +SNCR

Step 3: Evaluate Control Effectiveness of Remaining Technologies

*CDPHE:*

*SNCR:* TriState stated in the May 14, 2010 submittal that based on the boiler configuration, TriState could expect a continuous NO<sub>x</sub> reduction performance with SNCR technology in the range of 10 – 15%; the Divisions considers 15% to be a reasonable control effectiveness for SNCR.

*SCR:* TriState stated in the May 14, 2010 submittal the expected emission rates for Craig Units 1 and 2 when applying SCR are 0.08 lb/MMBtu. TriState did not specify if this estimate was a 30-day rolling average, although, as stated in the December 31, 2009 submittal, the baselines are averages of 30-day averages. The Division notes that several other Colorado facilities have noted SCR expectations of 0.070 lb/MMBtu or even lower. Additionally, a recent AWMA study found similar-sized EGUs achieve NO<sub>x</sub> reduction efficiencies greater than 85% with emission rates between 0.04 and 0.07 lb/MMBtu (during the ozone season). EPA’s AP-42 emission factor tables estimate SCR as achieving 75 – 85% NO<sub>x</sub> emission reductions. The Division adjusted TriState’s estimate to 0.07 lb/MMBtu based on the reasoning above.

*NPS:* CDPHE selected LNB+OFA+SNCR as BART at 0.24 and 0.26 lb/mmBtu with an estimated reduction of 24% and 30% for Units 1 and 2, respectively.

For its cost-effectiveness analysis, CDPHE has estimated that LNB+OFA+SCR can achieve 0.07 lb/mmBtu on an annual basis, which represents a 74% - 75% reduction by SCR from the emission rate to be achieved by LNB+OFA alone.<sup>2</sup> It is generally assumed that SCR can achieve at least 90% NO<sub>x</sub> reduction, and we have presented evidence in our General BART Comments demonstrating that SCR can achieve 0.05 lb/mmBtu (or lower) on similar wall-fired boilers.

We conclude that CDPHE has underestimated the ability of a modern SCR retrofit to reduce NO<sub>x</sub> emissions. Because such an underestimate adversely affects the cost-benefit analysis, we conducted our analysis as discussed in our General BART Comments and below.

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<sup>2</sup> CDPHE Table 13 appears to contain incorrect values for Baseline NO<sub>x</sub> emissions, SCR removal efficiency, and resultant emissions.

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

##### *CDPHE:*

*SNCR:* The cost effectiveness for SNCR on Units 1 and 2 (at 15% control efficiency) is approximately \$4,877 and \$4,712 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on wall fired boilers (similar to Units 1 and 2) achieving 0.50 – 0.65 lb/MMBtu and emission reductions of 30 – 50% as costing \$590 - \$1,100 per ton of NO<sub>x</sub> reduced, depending on initial capital costs and capacity factor. It should be noted that TriState is estimating resultant emission rates lower than 0.30 lb/MMBtu for both boilers, therefore costs will be higher. EPA’s SNCR Fact Sheet cites SNCR as costing from \$400 - \$2,500 per ton of NO<sub>x</sub> reduced. On a linear scale, based on the NESCAUM estimates and assuming an achieved rate of 0.23 lb/MMBtu, the costs should be approximately \$2,500 per ton. TriState and the Division’s revised estimates are above this range; the Division has inquired about the reagent and auxiliary power costs, but has not received feedback from TriState. The costs for these two items are higher than other Colorado facility estimates. Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. Therefore, the Division will use TriState’s capital and operation/maintenance costs for this analysis, but does not concur with the estimated costs.

*SCR:* Recent NESCAUM studies estimate SCR retrofits on wall fired boilers achieving NO<sub>x</sub> emission rates of 0.15 – 0.25 lb/MMBtu and emission reductions of 75 – 85% as costing \$1,700 - \$3,200 per ton of NO<sub>x</sub> reduced, depending on initial capital costs and capacity factor. It should be noted that TriState is estimating resultant emission rates lower than 0.15 lb/MMBtu for both boilers, therefore costs will be higher. TriState’s estimates are above this range; on a linear scale (achieving 0.07 lb/MMBtu); the costs should be approximately \$7,000 per ton. The Division’s revised cost estimates are close to this estimate; therefore, the Division concludes that these cost estimates are reasonable.

*NPS:* The “recent” studies cited by CDPHE are vintage 1998 and 2005, and do not reflect current capabilities of SCR.

Our review of Tri-State’s BART submittals for SCR leads us to conclude that Tri-State’s SCR costs are greatly inflated. A critical cost element is the Total Capital Investment (TCI). As discussed in our General BART Comments, SCR costs can be expected to fall between \$50 and \$300/kW, with the recent average at slightly below \$200/kW. Tri-State’s estimates are the highest we have seen at almost \$500/kW, and are not properly supported.

In its May 14, 2010, letter to Kirsten King, Tri-State makes the following assertions:

*Tri-State:* “As further response to this first item, below find Table 1 with **cost details** for SCR on Craig Station Units 1, 2 and 3.”

**NPS: Tri-State provides none of the information recommended by the BART Guidelines<sup>3</sup> to support its “cost details.”**

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<sup>3</sup> 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

*Tri-State:* It would take much more time to start over using the Control Cost Manual and not provide better data since the estimates provided have greater accuracy than the Control Cost Manual.

**NPS:** We produced our version of the Cost Manual approach in about a day and have provided it to many agencies.

*Tri-State:* Costs in Tables 1 and 2 were derived through **previous project experience, conceptual design of control systems, consideration of vendor data and information,** and knowledge of Tri-State's specific generation plants.

**NPS:** No evidence is provided to support this claim.

*Tri-State:* The basis for the direct costs specified in the tables includes the following:

- All capital cost estimates were determined in 2009 dollars.
- Sales tax is not included on new equipment.
- Escalation is included for most items, including labor.

**NPS:** Tri-State should explain what costs were escalated and how; this is typically not allowed.

*Tri-State:* Lost generation during tie-in outage, beyond the turbine/boiler outage length, if applicable. A one week contingency on outage length has been included.

**NPS:** Tri-State has claimed Lost Generation costs of \$12 - \$18 million but has provided no support or justification for the costs, the duration of the outages needed, and why time beyond normal scheduled outages would be necessary. For example, in its analysis for adding SCRs at the Navajo Generating Station, Salt River Project estimated:

- Utility Relocation Tie-In Outage – 1 week forced outage per unit
- Major Tie-In Outages – 8 week planned outage

*Tri-State:* Interest during construction @ \$26 million per unit.

**NPS:** This cost is usually not allowed—see General BART Comments.

*Tri-State:* Taxes are included..

**NPS:** Which taxes were included?

*Tri-State:* Catalyst costs. Waste disposal costs for SCR systems at Craig Station are based on expected disposal costs of deactivated catalyst based on a catalyst replacement plan. It is assumed that, over a 20-year period, spent catalyst is disposed four times and new catalyst is added five times. Catalyst costs are annualized. Spent catalyst would be returned to catalyst supplier.

**NPS:** Tri-State should explain its catalyst costs which appear to be more than double the Cost Manual estimates.

*Tri-State:* **G. Outage Requirements and Construction Sequence**

**(1) Craig Units 1 and 2**

SCR design configuration for Craig Unit 1 and 2 would allow the reactor box support structures, reactor boxes, and the majority of the inlet and outlet ductwork to be installed pre-outage with minimal impact to the operation of the plant. Early demolition of the hot-side ESPs would provide an area adequate to set cranes and other construction equipment in close proximity to the

work face. It would also allow small staging and fabrication areas to be established adjacent to construction.

The major outage work scope would include inlet and outlet duct tie-in; boiler and equipment stiffening; electrical and I&C terminations; start up; insulation and lagging demolition and replacement; and touch up painting. The execution plan for the tie-in work scope would need to be outlined in detailed work steps for each component to be removed or installed. It should be realized that the latest edition of NFPA 85 would recommend that each furnace be reinforced to be able to withstand a transient pressure excursion of up to +/- 35 inches of water. A need for stiffening of the boilers would need to be determined with further engineering study; if necessary, it would increase Craig Units 1 and 2 outage requirements to 10 consecutive weeks.

**NPS: The Tri-State outage plan appears to consist of speculative general statements with little concrete basis or specificity. Tri-State must show why it will cost \$12 - \$18 million in lost generation.**

#### **NPS Cost Analysis**

Although a 90% reduction from the emission rate to be achieved by LNB+OFA would lead to an annual average emission rate of 0.03 lb/mmBtu in this case, as a conservative estimate, we have assumed that SCR would achieve 0.05 lb/mmBtu (84% reduction) on an annual average basis.

In generating our SCR cost estimate, we note the following differences between our analysis and that provided by Tri-State:

Our review of 2005 – 2009 CAM data (Please see the “Unit emissions” tab of the workbooks in **Appendix C. “Craig SCR Costs”**) found that actual annual average hourly heat input rates exceed the maximum heat input rates used by CHPDE. Maximum actual total annual heat input was also greater than estimated by CHPDE, as were maximum actual annual emissions.

In our analyses, we used the maximum actual operating hours, maximum actual annual heat input, and maximum actual annual average hourly heat input. However, we also used the 2005 – 2009 average annual NO<sub>x</sub> emission rate (in lb/mmBtu), which was slightly higher than used by CDPHE, to estimate annual NO<sub>x</sub> emissions. In effect, we assumed that the units would operate at their historic maxima for operating hours and heat input, but emit at their historic average rate. The result was an annual NO<sub>x</sub> emission rate (Please see cell E31 on the “Boiler Calcs” tab.) that was greater than average and estimated by CDPHE, but comparable to the maximum actual annual emissions. As such, we based our estimates upon a greater gas flow that would be generated which would require a larger catalyst reactor, and more reagent would be required to treat the greater quantity of NO<sub>x</sub> emissions and the costs associated with reducing them.

We used representative unit costs for catalyst and electricity, and, although we question Tri-State’s estimated cost for ammonia, we used its \$600/ton value.

A critical cost element is the Total Capital Investment (TCI) upon which much of the EPA Cost Manual method is based. As discussed in our General BART Comments, SCR costs can be expected to fall between \$50 and \$300/kW, with the recent average at slightly below \$200/kW.

However, a rigid application of the Cost Manual tends to produce TCI that fall toward the lower end of the expected range, and company cost estimates typically substantially exceed the upper end of the range. In this case, the Cost Manual method yields \$81 - 84/kW (Please see cell L18 in the “ICC” tab.), which appears too low for EGUs this size and thus prompted us to over-ride the Cost manual’s TCI calculation. On the other hand, the CDPHE estimate of \$490/kW (cell O18) is far more expensive than the top of the range, and no reason has been provided to justify any extraordinary costs, further evaluation is warranted.

We have developed a hybrid approach that combines the Direct Capital Cost (DCC) provided by the source and the ratios applied by the Cost Manual to the DCC to generate the TCI. The Cost Manual 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. Instead, the CDPHE \$210 million TCI estimate is 172% (cells O17 and P17 on the “ICC” tab) of its \$122 million DCC estimate, and includes a \$26 million Allowance for Funds During Construction (AFUDC) which may not be justified (Please see our General BART Comments on AFUDC.)

Our next step assumed that the CDPHE estimate for DCC is reasonable, and applied the Cost Manual 141% ratio to estimate a new TCI. In this case, the result is a TCI of \$172 million @ \$401/kW (cells M20 and M21 on the “ICC” tab). Because this new TCI still far exceeds the range of real-world costs, it will not be used for further estimates. Instead, we assumed that a TCI equal to \$300/kW<sup>4</sup> would be representative of a “worst case” for this installation (cell C7 of the “Given/Assume” tab).

Annual Cost estimates are generated by a direct application of the Cost Manual method to the new TCI and other interim values. We found that CDPHE’s Direct Annual Cost estimates were usually higher than the Cost Manual estimates. The most significant differences were between the Annual Maintenance Costs, the Indirect Annual Cost (due to the different estimates of TCI) and the amount of NO<sub>x</sub> removed (due to our assumed higher SCR efficiency).

A summary of our analysis can be found on the near-far-right tab of our workbook. We believe that our estimation method is more transparent and truer to the EPA Cost Manual approach than that provided by CDPHE, and that our “worst-case” \$3,400 - \$3,500/ton results are better-supported by real-world industry experience.

#### Step 5: Evaluate Visibility Results

*CDPHE:* CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. Table 17 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in \$/deciview and the calculation methodology utilized by the Division.

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<sup>4</sup> This is the highest cost/kW for any SCR in the industry data discussed in our General BART Comments.

**Table 17: Visibility Results – NOx Control Options**

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	(\$/dv)
Max 24-hour	1&2	0.352	3.73	---	---	---
SNCR	1	0.236	3.42	0.31	0.08	\$ 12,327,922
	2	0.23	3.42	0.31	0.08	\$ 12,327,922
SCR	1	0.07	2.72	1.01	0.27	\$ 24,887,384
	2	0.07	2.75	0.98	0.26	\$ 25,652,365
Combo	1&2	0.07	1.17	2.56	0.69	\$ 19,537,034

Per the April 2010 modeling protocol<sup>22</sup>, to isolate the effects of a given unit for controls on a given pollutant, the Division has judiciously constructed each emissions scenario to isolate the impact of a given BART control on a given unit. For example, to determine the effect of a SO<sub>2</sub> BART control technology on a given unit, emission rates for the other pollutants and other BART-eligible units are held constant at pre-control levels. For BART sources with more than one BART unit, modeling the units individually would ignore important atmospheric chemical reactions that occur when units operate simultaneously. The combination scenario assumed both boilers with NO<sub>x</sub> emissions at 0.07 lb/MMBtu (SCR control) and SO<sub>2</sub> emissions at 0.10 lb/MMBtu (wet FGD control).

In situations where the BART-eligible units at a given BART-eligible source operate simultaneously, the sulfate and nitrate estimates from the modeling system will be more realistic, in general, if all BART units and all pollutants at a BART-eligible source are modeled together. The combined unit approach has the added benefit of allowing Colorado to estimate the net degree of visibility improvement from the simultaneous operation of BART controls on multiple units for multiple pollutants at a given BART-eligible source.

*NPS:* We commend CDPHE for its modeling approach, but model results should include all impacted Class I areas.

#### Step 6: Select BART Control

*CDPHE:* Based upon its consideration of the five factors summarized herein, the state has determined that NO<sub>x</sub> BART is SNCR controls at the following NO<sub>x</sub> emission rates:

Craig Unit 1: 0.27 lb/MMBtu (30-day rolling average)  
0.24 lb/MMBtu (rolling 12-month average)

Craig Unit 2: 0.27 lb/MMBtu (30-day rolling average)  
0.23 lb/MMBtu (rolling 12-month average)

For SNCR at Units 1 and 2, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented in Chapter 6 of the Regional Haze State Implementation Plan.

- Unit 1: \$4,877 per ton NO<sub>x</sub> removed; 0.31 deciview of improvement
- Unit 2: \$4,712 per ton NO<sub>x</sub> removed; 0.31 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements, leads the state to this determination. Although SCR achieves better emissions reductions, the expense of SCR was determined to be excessive and above the cost criteria presented above.

*NPS:* We have shown that application of real-world data from EPA (e.g., SCR @ 0.05 lb/mmBtu annual average) and industry sources (SCR < \$300/kW) results in much more realistic (\$3,400 - \$3,500/ton “worst-case”) cost-effectiveness estimates for SCR and, coupled with the \$16 million/dv cost-effectiveness of improving visibility at only the most-impacted Class I area, SCR is clearly BART. We also note that, even if one assume that SCR can achieve only 0.07 lb/mmBtu (annual average), its cost-effectiveness changes only slightly (\$3,600 - \$3,800/ton and \$16 million/dv at Mt. Zirkel).