

**NPS Comments on Reasonable Progress Analysis of Control Options For Tri-State  
Generation & Transmission Association, Inc. – Craig Station Unit 3  
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. 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**

Unit 3 is a dry-bottom wall-fired coal boiler rated at 4,600 MMBtu/hour (net 408 MW) and was placed in service in 1984. This unit is equipped with a baghouse system for controlling PM emissions, a dry lime system for control of SO<sub>2</sub> and low-NO<sub>x</sub> burners (LNB) with overfire air (OFA).

Of 3,558 EGUs, 2008 CAM data rank Unit 3 at #788 for SO<sub>2</sub> and #116 for NO<sub>x</sub>. CDPHE modeling data show that Craig Unit 3 has a maximum impact at Mt. Zirkel Wilderness Area of 4.99 dv. The cumulative impacts of Craig Unit 3 across the eleven Class I areas modeled is greater than 10 dv, which ranks this unit 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**

Tri-State identified two options for NO<sub>x</sub> control:

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

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

- Advanced OFA system or Rotating overfire Air (ROFA)
- 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)

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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, and San Juan Generating Station.

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

### Step 3: Evaluate Control Effectiveness of Remaining Technologies

#### *CDPHE:*

*SNCR:* Tri-State stated in the May 14, 2010 submittal that based on the boiler configuration, Tri-State could expect a continuous NO<sub>x</sub> reduction performance with SNCR technology in the range of 10 – 15%. This is based on Tri-State’s extensive research into the application of SNCR technology at Craig Station. The vast majority of the research was focused on system performance and impacts on plant performance. Tri-State staff conducted a visit to First Energy’s Eastlake and Sammis power plants in Ohio; this visit was specifically design to evaluate boiler designs due to the similarity in boiler/burner configurations similar to the Craig Station boilers. These estimates are lower than EPA’s SNCR Air Pollution Control Technology Fact Sheet, which estimates SNCR between 30 – 50% control. Other Colorado facilities estimated SNCR as achieving between 17 – 40% NO<sub>x</sub> control. Control effectiveness has been historically noted to be lower for wall fired boilers similar to the Craig boilers; therefore the Divisions considers 15% to be a reasonable control effectiveness for SNCR.

*SCR:* Tri-State stated in the May 14, 2010 submittal the expected emission rate for Craig Unit 3 when applying SCR are 0.08 lb/MMBtu. Tri-State 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 Tri-State’s estimate to 0.07 lb/MMBtu based on the reasoning above.

*NPS:* CDPHE selected LNB+OFA+SNCR as BART at 0.28 lb/mmBtu with an estimated reduction of 15% for Unit 3.

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 75% reduction by SCR from the emission rate to be achieved by LNB+OFA alone. It is generally assumed that SCR can achieve at least 90% NO<sub>x</sub> reduction, and we have presented evidence in our General 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.

### Step 4: Evaluate Impacts and Document Results

#### *CDPHE:*

*SNCR*: A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses. The Tri-State-estimated SNCR costs for operating expenses are 70% for Craig Unit 3. Since SNCR is an operating expense-driven technology, its cost varies directly with NO<sub>x</sub> reduction requirements and reagent usage. There is a wide range of cost effectiveness for SNCR due to different boiler configurations and site-specific conditions, even with a given industry. Cost effectiveness is impacted primarily by uncontrolled NO<sub>x</sub> level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.

The cost effectiveness for SNCR on Unit 3 (at 15% control efficiency) is approximately \$4,887 per ton. Recent NESCAUM studies estimate SNCR retrofits on wall fired boilers (comparable to Unit 3) 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 Tri-State 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. Tri-State and the Division's revised estimates are above this range; the Division inquired about the reagent and auxiliary power costs; Tri-State responded on July 30, 2010 adjusted the auxiliary power and lost generation costs for all of the Craig Units for both SNCR and SCR. Tri-State also provided further information regarding the cost of potential reagent options. The costs for these two items remain higher than other Colorado facility estimates; however, Tri-State has provided adequate information detailing the reasoning for power and reagent costs. The Division and Tri-State still do not completely concur on other cost items, including an annual 3% escalation rate for capital material, capital labor, capital indirect, and operation and maintenance. Additionally, similar Colorado facility cost estimates fall within the EPA SNCR Fact Sheet range. The Division will use Tri-State's capital and operation/maintenance costs for this analysis in the absence of additional information at this time.

*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 Tri-State is estimating resultant emission rates lower than 0.15 lb/MMBtu for both boilers, therefore costs will be higher. Tri-State'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 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 \$600/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>2</sup> to support its “cost details.”**

*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 \$30 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 @ \$29 million.

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

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<sup>2</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

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 three-times the Cost Manual estimates.**

*Tri-State:*

## **G. Outage Requirements and Construction Sequence**

### **(2) Craig Unit 3**

Execution plans for the tie-in work scope would need to be outlined in detailed work steps for each component to be removed or installed. This would ensure that craft manpower, tooling, rigging, crane usage, and shift schedules are optimized. Structural framework and gas ductwork would need to be prefabricated into modular sections to the extent possible to limit assembly time at heights and expedite the outage schedule. Reactor box ductwork tie-in work scope would be complex with multiple challenges to execution, including congested work areas which limit crew sizes, reduced heavy lift capacity, work at height and adjacent to operational plant equipment, and rigging and setting heavy modular components. Combined with a stiffening of the boiler, the need for which would need to be determined through further engineering study similar to that mentioned above for Craig Units 1 and 2, outage requirements for Craig Unit 3 would be 12 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 \$30 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 2000 – 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.

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 CDPHE average annual NO<sub>x</sub> emission rate (in lb/mmBtu) 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 projected average rate. The result was an annual NO<sub>x</sub> emission rate (Please see cell E31 on the “Boiler Calcs” tab.) that was less than estimated by CDPHE. As such, we based our estimates upon a greater gas flow that would be generated which would require a larger catalyst reactor, but less reagent would be required to reduce the smaller quantity of NO<sub>x</sub> emissions.

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 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 \$75/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 \$592/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 \$242 million TCI estimate is 183% (cells O17 and P17 on the "ICC" tab) of its \$122 million DCC estimate, and includes a \$29 million Allowance for Funds During Construction (AFUDC) which may not be justified (Please see our General 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 \$186 million @ \$456/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>3</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 higher than the Cost Manual estimates. The most significant differences were between the Annual Maintenance Costs, Annual Catalyst Cost, and the Indirect Annual Cost (due to the different estimates of TCI).

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" \$3,700/ton results are better-supported by real-world industry experience.

#### Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. The state

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<sup>3</sup> This is the highest cost/kW for any SCR in the industry data discussed in our General Comments.

projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.

**CDPHE Table 20: Visibility Results – NO<sub>x</sub> Control Options**

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)	Output (@ 98 <sup>th</sup> Percentile Impact)	98 <sup>th</sup> Percentile Impact Improvement	98 <sup>th</sup> Percentile Improvement from Maximum
			(dv)	(Δ dv)	(%)
Max 24-hour 2nd half 2009 NOx rate	3	0.365	5.20	---	---
2009 New LNBS	3	0.283	4.99	0.21	4%
SNCR	3	0.240	4.88	0.32	6%
SCR	3	0.070	4.41	0.79	15%

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

Step 6: Select RP Control

*CDPHE:*

Based upon its consideration of the five factors summarized herein, the state has determined that NOx RP for Craig Unit 3 is SNCR control at the following NOx emission rates:

Craig Unit 3: 0.28 lb/MMBtu (30-day rolling average)  
0.24 lb/MMBtu (rolling 12-month average)

For SNCR at Unit 3, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls with guidance cost criteria discussed in section 8.4 above.

Unit 3: \$4,887 per ton NOx removed; 0.32 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 of the Regional Haze State Implementation Plan.

*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 (\$3,700/ton “worst-case”) cost-effectiveness estimates for SCR and, coupled with the \$19 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 (\$4,000/ton and \$19 million/dv at Mt. Zirkel).