

NPS Comments
APS Cholla Generating Station BART Analysis and Determination

November 29, 2010

Process Description

The Arizona Public Service (APS) Cholla Generating Station (Cholla) is located approximately two miles east of Joseph City along Interstate 40 in Navajo County, Arizona, and consists of the following four electric generating units with a total generating capacity of 1,150 megawatts (MW).

Unit 1: 125 MW
Unit 2: 300 MW
Unit 3: 300 MW
Unit 4: 425 MW

Each unit is a coal-fired steam-generating unit equipped with a tangentially-fired, dry-bottom boiler and burns bituminous or sub-bituminous coal purchased from the Lee Ranch and El Segundo mines. Of 1,228 plants, EPA Clean Air Markets (CAM) data for 2008 rank the Cholla facility #143 for SO₂ and #88 for NO_x.

Cholla Units 2, 3 and 4 are subject-to-BART, and presumptive BART limits apply at this facility with a total capacity greater than 750 MW. Of 3,558 EGUs, 2008 CAM data rank Cholla Units 2, 3, and 4 at #821, #230, and #527, respectively for SO₂, and #302, #241, and #335, respectively for NO_x.

Despite the improper modeling methods applied by APS and the resulting underestimations of impacts, the cumulative impacts of Cholla Units 2, 3, and 4 across the 13 Class I areas modeled rank among highest of any facility we have evaluated under the BART program.

Nitrogen Oxides (NO_x) BART Analysis and Determination for Units 2, 3 and 4

Step 1: Identify the Existing Control Technologies in Use at the Source

The Cholla BART Analysis was completed in late 2007. At that time, the Units were equipped with Close-coupled Overfire Air (COFA). Overfire air is used to reduce NO_x by reducing excess air in the combustion zone. Low NO_x Burner (LNBs) and Separated Overfire Air (SOFA) were installed on Units 2, 3 and 4 in March 2008, May 2009 and May 2008, respectively. LNBs and SOFAs are utilized for increased NO_x reduction.

Step 2: Identify All Available Retrofit Control Options

APS has identified the following available retrofit control technologies for NO_x control in Units 2, 3 and 4.

- LNB with Separate Overfire Air (SOFA) System
- LNB with SOFA and Selective Non-Catalytic Reduction (SNCR) System
- Rotating Opposed Flow Air system (ROFAs)
- ROFA with Rotary Mixing of Additives (Rotamix)
- LNB with SOFA and Selective Catalytic Reduction (SCR)

NPS: We agree with the suite of options.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the options identified above are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

NPS: ADEQ selected LNB+SOFA as BART at 0.22 lb/mmBtu with an estimated reduction of 46% - 56%.

For its cost-effectiveness analysis, ADEQ has estimated that LNB+OFA+SCR can achieve 0.07 lb/mmBtu on an annual basis,¹ which represents a 68% 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_x reduction, and we have presented evidence in our General BART Comments demonstrating that SCR can achieve 0.05 lb/mmBtu (or lower) on similar tangentially-fired boilers.

We conclude that ADEQ has underestimated the ability of a modern SCR retrofit to reduce NO_x 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 5: Evaluate the Energy and Non-Air Quality Environmental 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: Please see our General BART Comments.

Economic Impacts

NPS: Although a 90% reduction from the emission rate to be achieved by LNB+OFA would lead to an annual average emission rate of 0.02 lb/mmBtu in this case, as a conservative estimate, we have assumed that SCR would achieve 0.05 lb/mmBtu (77% reduction) on an annual average basis.

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

¹ ADEQ appears to have assumed that SCR would achieve 0.07 lb/mmBtu regardless of averaging time. While we agree that 0.07 lb/mmBtu is a reasonable estimate for input into a visibility model that requires a 24-hour emission rate, it is always the case that average emission rates decrease as the averaging period increases. The data we present in our General BART Comments indicate that, if SCR can achieve 0.07 lb/mmBtu on a 24-hour basis, it is likely that that same SCR is achieving 0.06 lb/mmBtu (or lower) on a 30-day average basis and 0.05 lb/mmBtu (or lower) on an annual average.

Our review of pre-modification 2000 – 2007 CAM data (Please see the “Unit emissions” tab of the workbooks in **Appendix**.) found that APS’ estimates were higher than maximum actual annual emissions.

In our analyses, we used the maximum actual operating hours, maximum actual annual heat input, and APS’ estimate for actual maximum hourly heat input. However, we also used the 2000 – 2007 average annual NO_x emission rate (in lb/mmBtu), which was lower than used by APS, to estimate annual NO_x 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_x emission rate (Please see cell E31 on the “Boiler Calcs” tab.) that was greater than average, but less than the maximum annual emissions estimated by APS. As such, based on our estimates, less reagent would be required to treat the lesser quantity of NO_x emissions and the costs associated with reducing them would be lower.

We used ADEQ’s estimates for costs associated with LNB+OFA, and APS’ unit costs for catalyst, reagent, and electricity.

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 costs 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 \$67 - \$74/kW (Please see the “ICC” tab cell L18.), which appears too low for EGUs this size and thus prompted us to override the Cost manual’s TCI calculation. On the other hand, the APS estimate of \$249 - \$258/kW (Please see the “ICC” tab cell P18.) is more expensive than average, and no reason has been provided to justify any exceptional costs, so 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 N17) of the DCC (cell L4), and that the costs that comprise the TCI will also be ratios of the DCC. Instead, the APS \$77 - \$106 million TCI estimates are 258% (cells P17 and Q17 on the “ICC” tab) of their corresponding DCC estimates, and include a \$3 - \$5 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 APS estimate for DCC is reasonable, and applied the Cost Manual 141% ratio to estimate a new TCI (cells N20 and N21 on the “ICC” tab). Because this new \$136 - \$141/kW TCI falls within the expected values for EGUs of this size, it will be used for further estimates and is fed back to cell C7 of the “Given/Assume” tab and to cell F5 on the “Ann Cost” tab.

Annual Cost estimates (Please see the “Ann Cost” tab.) are generated by a direct application of the Cost Manual method to the new TCI and other interim values. We found that APS’ Direct Annual Cost estimates were usually higher than the Cost Manual estimates. The most significant

differences were between the Indirect Annual Cost (due to the different estimates of TCI) and the amount of NO_x removed. We believe that our estimation method is more transparent and truer to the EPA Cost Manual approach than that provided by APS, and that our \$1700 - \$1900/ton results are better supported by real-world industry experience.

Step 6: Evaluate Visibility Impacts

ADEQ: CALPUFF modeling was performed at 13 Class I areas that are located within 300 kilometers of Cholla Power Plant. The impacts are modeled for different NO_x control scenarios, combined with SO₂ and PM₁₀ technologies at Petrified Forest National Park

NPS: Because APS used background ammonia levels that are unacceptably low (Section 4.4.1 of the company report), the visibility benefits are under-estimated and the Evaluation of Visibility Impacts step is unacceptable.

Step 7: BART Selection

ADEQ: According to the Regional Haze Rule, only dV changes in excess of 1.0 dV are perceptible.

A review of the data presented in Tables 3, 4, and 5 indicates that CALPUFF model-predicted visibility improvements (delta dV) for all five NO_x control scenarios are less than 0.5 dV. For example, in the case of Unit 3, the dV changes range from 0.126 dV for the LNB with SOFA (Scenario 1) to 0.230 dV for LNB with SOFA and SCR (Scenario 5). The change in dV between the least expensive and most expensive NO_x control technologies (the two noted above) is only 0.104 dV. The corresponding capital costs are \$5.4 million for LNB/SOFA and \$82.8 million for LNB/SOFA with SCR.

Based on these facts and the five-factor analysis discussed above, ADEQ has concluded that LNB with SOFA constitute BART for NO_x emissions for Cholla Units 2, 3, and 4.

NPS: EPA has explicitly rejected the premise that visibility improvement must be perceptible to qualify as BART. Because of the improper visibility modeling analysis noted above, ADEQ has not conducted a valid five-factor BART analysis.

ADEQ estimates that all of the options it evaluated would cost less than \$2,600/ton to implement. BART, like BACT, is not necessarily the most-cost-effective option. Instead, it is typically chosen based upon a comparison to options selected by other regulatory agencies in similar situations. 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 is using \$5,000/ton as a non-binding “guidepost,” and Wisconsin is using \$7,000 - \$10,000/ton as its BART threshold.² Because BART is the best option that meets the selection criteria, SCR should be selected as BART due to the reasonable cost/ton and the benefits to multiple Class I areas.

² “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

PM₁₀ BART Analysis

Step 1: Identify the Existing Control Technologies in Use at the Source

Unit 2 currently has a mechanical dust collector for control of PM₁₀ emissions. Additional particulate matter control is provided by a Venturi scrubber. Cholla 2 is currently able to achieve emission rate of 0.020 lb/MMBtu.

Unit 3 was previously equipped with a hot-side ESP and was able to achieve an emission rate of 0.015 lb/MMBtu of PM₁₀. The facility completed installation of a fabric filter in May 2009. With the installation of the fabric filter, the facility expects to consistently achieve an emission rate of 0.015 lb/MMBtu for PM₁₀.

Unit 4 was previously equipped with a hot-side ESP and was able to achieve an emission rate of 0.024 lb/MMBtu of PM₁₀. The facility completed installation of a fabric filter in May 2008. With the installation of the fabric filter, the facility expects to consistently achieve an emission rate of 0.015 lb/MMBtu for PM₁₀.

Step 2: Identify All Available Retrofit Control Options

Since Units 3 and 4 will be equipped with fabric filters, and fabric filters are considered the top control technology for reducing PM emissions. As a result, no other technology is considered for these two Units. The following retrofit technologies are considered for Unit 2:

- Electrostatic Precipitators
- Fabric Filters

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the identified control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Fabric filters are proven to be highly effective and provide a consistent particulate matter reduction. The emissions at the outlet of fabric filter are expected to be less than 0.015 lb/MMBtu.

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results Economic Impacts

APS has chosen to install a new fabric filter at an annual cost of \$9.4 million to remove 58 tons per year. The cost-effectiveness of this strategy is \$160,747/ton.

Step 6: Evaluate Visibility Impacts

The installation of a fabric filter is the only option considered for BART for all the 3 units.

Step 7: BART Selection

Based upon its review of the company's BART analysis and the information provided above, the Department has determined that, fabric filter with an associated emission limit of 0.015 lb/MMBtu is the BART for control of PM₁₀ for Units 2, 3 and 4.

NPS: We concur.

SO₂ BART Analysis

Step 1: Identify the Existing Control Technologies in Use at the Source

According to ADEQ:

Unit 2. This unit is equipped with four Venturi flooded disc scrubbers/absorber with lime reagent for SO₂ control. Currently, APS Cholla is able to achieve 0.14 lb/MMBtu to 0.25 lb/MMBtu of SO₂ on Unit 2.

Unit 3. This unit did not have any SO₂ control technology when the BART analysis was completed in late 2007. The facility installed a new wet lime scrubber in May 2009 to capture and treat all flue gases. This will result in Unit 3 consistently meeting an emission limit of 0.15 lb/MMBtu.

Unit 4. This Unit was previously operating with 36% flue gas scrubbing with emission rate of 0.734 lb/MMBtu. The facility installed a new wet lime scrubber in May 2008 to capture and treat all flue gases. This will result in Unit 4 consistently meeting an emission limit of 0.15 lb/MMBtu.

Step 2: Identify All Available Retrofit Control Options

Unit 2. The facility plans to remove the Venturi section of the scrubber and considered a wet lime scrubber section for possible operational upgrades. Installation of bag filter as a part of BART will improve the performance of scrubber due to decreased plugging of scrubber. The facility expects to achieve 0.15 lb/MMBtu consistently with these operational upgrades.

Unit 3. In late 2007, APS Cholla identified the following available retrofit control technologies for SO₂ control in Unit 3:

- Dry Flue Gas Desulfurization (FGD) System
- Dry Sodium Sorbent Injection
- Wet Lime Scrubber

Subsequently, Cholla installed a new Wet Lime Scrubber on Unit 3 in May 2009. Therefore, the new wet lime scrubber, as described above, is the only retrofit control technology considered for this unit.

Unit 4. The wet lime scrubber, as described above, is the only retrofit control technology considered for this unit.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the identified control technology upgrades are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

NPS: ADEQ must evaluate the potential of the scrubbers and possible upgrades to achieve emission rates lower than the presumptive rate. The APS reports indicate that uncontrolled SO₂ emissions are 1.00 lb/mmBtu, and the ADEQ proposal would reduce SO₂ emissions by 85% down to 0.15 lb/mmBtu.

For example, Minnesota is requiring that Xcel Energy upgrade the existing scrubbers at its King and Sherburne County plants to meet 0.12 lb/mmBtu.

According to the Colorado Department of Public Health & Environment, “Colorado Ute Electric Association, which owned Craig before TriState, installed wet limestone FGD systems, on Craig Units 1 and 2 when the units began operations in 1980 and 1979, respectively. TriState upgraded these FGD systems in the 2003 – 2004 timeframe. The current Operating Permit also requires that 100% of the flue gas in the FGD be treated and that the Craig Unit 1 and 2 FGDs be designed to meet at least a 97.3% removal rate.”

In the late 1990s, Public Service of New Mexico (PSNM) replaced its existing SO₂ controls with new limestone forced-oxidation scrubbers. In 2005 PSNM agreed to upgrade the scrubbers by 2009 such that the annual rolling average SO₂ percentage reduction for San Juan Units 1, 2, 3, and 4 shall not be less than 90% for each unit (based upon measurements upstream and downstream of scrubbers).

It is clear that existing scrubbers can achieve better removal efficiency and lower emission rates than the 85% and 0.15 lb/mmBtu proposed by ADEQ. ADEQ must evaluate those options.

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Economic Impacts for Unit 3

Control	Emission Rate (lb/MMbtu)	Total Emssn (Tons/Yr)	Total Emssn Rdctn (Tons)	Annlzd Cost (Million\$)	Cost/Ton (\$)	Incrmntl Cost/ton (\$/ton)
Baseline (no control)	1.00	11,033	-	-	-	-

Wet Lime scrubber	0.15	1,655	9,378	\$8.80	936	\$936
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Step 6: Evaluate Visibility Impacts

A Visibility Impact Analysis was not performed for SO₂ since the existing scrubbers are proposed as BART.

Step 7: BART Selection

ADEQ: Based upon its review of the BART analysis provided by the company, and the information provided above, the Department has determined that wet lime scrubbers with an associated emission limit of 0.15 lb/MMBtu is the BART for control of SO₂ for Units 2, 3 and 4.

NPS: Neither APS nor ADEQ has conducted a proper BART analysis of upgrading the existing scrubbers. We suggest that ADEQ require that Cholla Units 2, 3, and 4 achieve at least 90% SO₂ removal across the scrubbers, not to exceed 0.12 lb/mmBtu.