NPS Comments
Arizona Electric Power Cooperative (AEPCO) – Apache Generating Station BART Analysis and Determination

November 29, 2010

Process Description

The Apache Generating Station consists of seven electric generating units (two coal/natural gas-fired steam electric units, a natural gas/fuel oil-fired steam electric, combined cycle unit, and four natural gas/fuel oil-fired turbines) with a total generating capacity of 560 megawatts (MW). The power plant is located approximately three miles southeast of the town of Cochise in Cochise County. Apache Generating Station Units 1, 2, and 3 are potentially subject-to-BART. Of 1,228 plants, EPA Clean Air Markets (CAM) data for 2008 rank the Apache facility #352 for SO_2 and #141 for NO_X.

Steam Unit 1 (ST1)

Apache Steam Unit 1 is a wall-fired steam-electric generating unit that can burn natural gas and numbers 2 through 6 fuel oils. The unit is permitted to produce up to a maximum capacity of 85 MW of electricity. Since 2000, SO_2 emissions have not exceeded one ton per year (tpy), and NO_X emissions have averaged 0.14 lb/mmBtu and declined to 30 – 60 tpy.

NO_x BART Analysis

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

There is no NO_x emissions control equipment installed on ST1.

Step 2: Identify All Available Retrofit Control Options

The second step of the BART process is to evaluate NO_x control technologies with practical potential for application to ST1, including those control technologies identified as BACT or LAER by permitting agencies across the United States. ST1 NO_x emissions are currently controlled through the use of good combustion practices.

The following potential NO_x control technology options were considered:

- New LNBs with Cver-Fire Air (OFA)
- Flue Gas Recirculation (FGR)
- Rotating Opposed Fire Air (ROFA)
- LNBs with selective non-catalytic reduction system (SNCR and Rotamix)
- LNBs with selective catalytic reduction system (SCR)
- Neural Net Controls

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
ADEQ has estimated the installation of LNB with FGR can achieve a NO_x emissions limit of 0.056 lb/MMBtu when burning PNG, and 0.06 lb/MMBtu when burning No. 2 fuel oil.

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

ADEQ has estimated that LNB with FGR will have a Total Capital Investment of $1.2 million, a Total Annual Cost of $0.552 million/yr, and cost-effectiveness of $1,856/ton.

Step 6: Evaluate Visibility Impacts
ADEQ estimates the total deciview reduction for Chiricahua Wilderness Area and National Monument at 0.194 dv.

Step 7: BART Determination

ADEQ has determined that, for Unit 1, BART for NO_x is the installation of LNB with FGR with a NO_x emissions limit of 0.056 lb/MMBtu when burning PNG, and 0.06 lb/MMBtu when burning No. 2 fuel oil. The cost-effectiveness is $2.8 million/dv.

PM_{10} BART Analysis

The PM_{10} BART analysis is only completed for the case when ST1 burns 100 percent No. 6 fuel oil. This was done for comparison only, as AEPCO has never combusted No. 6 fuel oil in the unit).

SO_2 BART Analysis

Emissions indicate that BART analysis is not required when ST1 burns PNG or fuel oil No. 2. ADEQ has determined that, for Unit 1, BART for SO_2 is the use of PNG or No. 2 fuel oil with an SO_2 emissions limit of 0.00064 lb/MMBtu when burning PNG, and 0.051 lb/MMBtu when burning No. 2 fuel oil.

Steam Units 2 and 3

Steam Units 2 and 3 are similar 195 MW natural gas and coal-fired steam electric generating units equipped with dry-bottom turbo-fired coal boilers. Of 3,558 EGUs, 2008 CAM data rank Units 2 and 3 at #909 and #823, respectively for SO_2, and #344 and #261, respectively for NO_X. ADEQ modeling data show that Apache Units 2 and 3 have a combined maximum impact at Chiricahua Wilderness Area and National Monument of 4.84 dv. The cumulative impacts of

Apache Units 2 and 3 across the nine Class I areas modeled is 20.5 dv, which ranks these units among the highest[1] of any facility we have evaluated under the BART program.

NO_x BART Analysis

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

Both Units 2 and 3 currently use OFA and under-fired air systems to control NO_x emissions.

Step 2: Identify All Available Retrofit Control Options

ADEQ: The Units are dry turbo-fired boilers, with 12 Riley directional flame burners. The following potential NO_x control technology options were considered:

- New/modified state-of-the-art LNBs with advanced OFA
- Rotating opposed fire air (ROFA)
- Selective non-catalytic reduction system (Rotamix and SNCR)
- Selective catalytic reduction (SCR) system
- Neural Network Controls/Boiler Combustion Controls (Neural Net)

NPS: ADEQ also considered combinations of control options such as LNB+OFA+SCR

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

NPS: ADEQ selected LNB+OFA as BART at 0.31 lb/mmBtu with an estimated reduction of 34% and 28% for Units #2 & #3, respectively.

For its cost-effectiveness analysis, ADEQ has estimated that LNB+OFA+SCR can achieve 0.07 lb/mmBtu on an annual basis,[2] which represents a 77% 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.

[1] The highest are Cholla Generating Station, Coronado Generating Station, Four Corners Power Plant, Navajo Generating Station, Centralia, PGE Boardman, San Juan Generating Station.

[2] 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.

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 0.03 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 AEPCO:
Our review of 2000 – 2009 CAM data (Please see the "Unit emissions" tab of the workbooks in **Appendix**.) found that actual annual average hourly heat input rates exceed the maximum heat input rates used by AEPCO. Maximum actual total annual heat input was also greater than estimated by AEPCO, 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 2000 – 2009 average annual NO_X emission rate (in lb/mmBtu), which was lower than used by AEPCO, 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 and estimated by AEPCO, but less than 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_X emissions and the costs associated with reducing them.

We used ADEQ's estimates for costs associated with LNB+OFA, and AEPCO's 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 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 $90/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 AEPCO estimate of $226/kW (cell P18) is more expensive than average, and no reason has been provided to justify any exceptional 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 N17) of the DCC (cell L4), and that the costs that comprise the TCI will also be ratios of the DCC. Instead, the AEPCO $44 million TCI estimate is 161% (cells P17 and Q17 on the "ICC" tab) of its $27 million DCC estimate, and includes a $3 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 AEPCO 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 $38 million @ $197/kW (cells N20 and N21 on the "ICC" tab). Because this new TCI falls very near the expected $200 average, 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 are generated by a direct application of the Cost Manual method to the new TCI and other interim values. We found that AEPCO's 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 (due to our assumed higher SCR efficiency).

A summary of our analysis can be found on the 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 AEPCO, and that our $1500 - $1700/ton results are better supported by real-world industry experience.

Step 6: Evaluate Visibility Impacts

ADEQ estimates the deciview reduction from each EGU provided by its BART proposal to be 0.21 – 0.27 dv for the most-impacted Class I, the Chiricahua Wilderness Area and National Monument. The results provided by AEPCO show a cumulative improvement of 0.56 – 0.73 dv across the four Class I areas for which results were provided.

ADEQ estimates the deciview reduction from each EGU provided by SCR to be 0.63 – 0.68 dv for the Chiricahua Wilderness Area and National Monument. The results provided by AEPCO show a cumulative improvement of 1.68 – 1.82 dv across the four Class I areas for which results were provided.

Step 7: BART Selection

ADEQ: After reviewing the company's BART analysis, and based upon the information above, ADEQ has determined that, for Units 2 and 3 BART for NO_x is new LNBs with OFA system with a NO_x emissions limit of 0.31 lb/MMBtu for both Units 2 and 3.

NPS: ADEQ estimates that all of the options it evaluated would cost less than $2,200/ton and $10 million/dv to implement, which is well below the $14 - $18 million/dv average of BART proposals across the nation. 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.[3] Because BART is the best option that meets the selection criteria, SCR should be selected as BART due to the reasonable cost/ton, the lower-than-average cost/deciview, and the benefits to several Class I areas.

PM_{10} BART Analysis

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

Both Steam Units 2 and 3 are currently equipped with hot-side Electrostatic Precipitators (ESPs).

Step 2: Identify All Available Retrofit Control Options

ADEQ: Steam Units 2 and 3 are currently equipped with hot-side ESPs. Historically, outlet ESP particulate emissions on Units 2 and 3 have ranged from approximately 0.007 to 0.045 lb/MMBtu. This wide range in outlet emissions can in part be attributed to the hot-side operation, as well as the wide variety of coals being burned in the boilers. Hot-side ESP effectiveness may also be impacted by sodium content in the ash.

Three retrofit control technologies have been identified for additional particulate matter control:

- Performance upgrades to existing hot-side ESP
- Replace current ESP with a fabric filter unit
- Install a polishing fabric filter after ESP

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

ADEQ Table 12 lists the various control technologies and estimated emissions rates.

Table 12: Control Technology and Respective Emission Rates

[3] “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

Control Technology	Expected PM_{10} Emission Rate
ESP Upgrades	0.03 lb/MMBtu
Full size fabric filter	0.015 lb/MMBtu
Polishing Fabric Filter	0.015 lb/MMBtu

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

Specific costs for the precipitator upgrades were not evaluated as AEPCO has yet to evaluate the upgrades that may be applicable to Units 2 and 3.

Step 6: Evaluate Visibility Impacts

Visibility improvements for the precipitator upgrades were not evaluated.

Step 7: BART Selection

ADEQ: Based upon its review of the analysis provided by AEPCO, and the information provided above, ADEQ has determined that BART for PM_{10} emissions is upgrades to the existing ESP and a PM_{10} emissions limit of 0.03 lb/MMBtu for both Units 2 and 3. The upgrades to the existing ESP will involve a possible installation of a flue gas conditioning system, improvements to the scrubber bypass damper system, and implementing programming optimization measures for ESP automatic voltage controls.

NPS: We concur.

SO_2 BART Analysis

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

Units 2 and 3 currently operate wet limestone scrubbers for SO_2 removal, with current emissions of 0.184 lb/MMBtu and 0.151 lb/MMBtu respectively.

Step 2: Identify All Available Retrofit Control Options

Enhancement of current wet limestone scrubber or SDAS was the only SO_2 control technology option considered

The EPA BART guidelines state that for existing units with SO_2 controls achieving at least 50 percent SO_2 removal, cost-effective scrubber upgrades should be considered. EPA has recommended consideration of the following potential upgrades:

- Elimination of bypass reheat
- Installation of liquid distribution rings
- Installation of perforated trays
- Use of organic acid additives
- Improve or upgrade scrubber auxiliary system equipment

- Redesign spray header or nozzle

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

ADEQ: When evaluating the control effectiveness of SO_2 reduction technologies, each option can be compared against benchmarks of performance. In its BART analysis, AEPCO chose to compare its proposed technology upgrades to EPA's presumptive BART emission limitations. According to EPA's BART guidance documents, the presumptive limit for SO_2 on a BART-eligible coal-burning unit, used here as a point of reference, is 95 percent removal, or 0.15 lb/MMBtu.

NPS: ADEQ must evaluate the potential of the scrubber upgrades to achieve emission rates lower than the presumptive rate. The AEPCO reports indicate:

- For Unit #2, uncontrolled SO_2 emissions are 0.69 lb/mmBtu, and current controls reduce SO_2 emissions by 73% down to 0.18 lb/mmBtu.
- For Unit #3, uncontrolled SO_2 emissions are 0.69 lb/mmBtu, and current controls reduce SO_2 emissions by 78% down to 0.15 lb/mmBtu.

For example, Minnesota is requiring that Xcel Energy upgrade the existing scrubbers at it 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 SO_2 controls with new limestone forced-oxidation scrubbers. In 2005 PSNM agreed to upgrade the scrubbers by 2009 such that the annual rolling average SO_2 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 be upgraded to achieve better removal efficiency and lower emission rates than the 78% 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

Over the past several years AEPCO has completed several scrubber upgrades to improve performance, including the following:

- Elimination of flue gas bypass
- Splitting the limestone feed to both the absorber feed tank and tower sump
- Upgrade of the mist eliminator system
- Installation of suction screens at pump intakes
- Automation of pump drain valves
- Replacement of scrubber packing with perforated stainless steel trays

Dibasic acid additive was tested; however results did not show significantly higher SO_2 removal.

Energy Impacts

Upgraded operation of the existing wet limestone scrubber or SDAS system is not expected to result in any additional power consumption.

Environmental Impacts

There will be incremental additions to scrubber waste disposal and makeup water requirements and a reduction of the stack gas temperature if there is elimination of flue gas bypass.

Economic Impacts

There are no anticipated cost impacts attributable to upgraded scrubber operation.

Step 6: Evaluate Visibility Impacts

A Visibility Impact Analysis was not performed for SO_2 since the existing scrubbers are proposed as BART.

Step 7: BART Selection

ADEQ: After reviewing the company's BART analysis, and based upon the information above, ADEQ has determined that BART for SO_2 emissions is no new controls and an emission limit of 0.15 lb/MMBtu.

NPS: Neither AEPCO nor ADEQ has conducted a proper BART analysis of upgrading the existing scrubbers. We suggest that ADEQ require that Apache Units 2 and 3 achieve at least 90% SO_2 removal across the scrubbers, not to exceed 0.12 lb/mmBtu.