NPS Comments on the CDPHE Best Available Retrofit Technology (BART) Analysis of Control Options for Colorado Energy Nations, Golden, Colorado
November 15, 2010

The CENC facility is located in Golden, Colorado and consists of five (5) boilers and the associated equipment for coal and ash handling. The boilers provide steam for one (1) 20 MW generator, two (2) 10 MW generators, and for industrial use. The boilers are rated at 228 MMBtu/hr (Boilers 1 and 2), 225 MMBtu/hr (Boiler 3), 360 MMBtu/hr (Boiler 4) and 650 MMBtu/hr (Boiler 5). Boilers 1 and 2 normally operated in hot standby mode or when one of the coal boilers (Boilers 3, 4, or 5) is down. Boilers 3, 4, and 5 are controlled for PM/PM10 by separate fabric filter baghouses, which were installed at the time of construction for each boiler. The coal is low sulfur, high heating value bituminous coal from western Colorado. Boilers 4 and 5 are equipped with pulverizers that process the coal directly into the fire zone. The ash and flyash from the boilers may be sold or transported off-site for disposal. Therefore, all fugitive dust sources at the facility are related to coal conveying or ash handling. Boilers 4 and 5 are considered BART-eligible.

Remaining Useful Life

CDPHE: CENC asserts that there are no near-term limitations on the useful life of these boilers, so it can be assumed that they will remain in service for the 20-year amortization period. Thus, this factor does not influence the selection of controls.

CDPHE used years 2006 – 2008 (annual averages and 30-day rolling) for baseline emissions for reduction and cost calculations. The highest 24-hour peak emission rate during this timeframe was used for modeling visibility results. Boiler 4 is mainly fired on coal and can be fired on natural gas. Fuel oil may be used as a backup fuel, but has not been used in recent years. Boiler 5 is fired on coal, with backup oil firing. Either boiler also may fire ethanol or sludge from the Coors Brewery.

CDPHE Table 2: CENC Boilers 4 and 5 Baseline Emissions

	Boiler 4		Boiler 5	
Pollutant	Annual Emissions (tpy)	30-day rolling average emissions (lb/MMBtu)	Annual Emissions (tpy)	30-day rolling average emissions (lb/MMBtu)
NOx	600	0.5	691	0.34
SO2	781	0.64	1406	0.71
PM10	11	0.003	18	0.01

<u>Sulfur Dioxide (SO2)</u>

<u>Step 1: Identify All Available Technologies</u>

CDPHE: CENC identified four SO_2 control options:

- Flue gas desulfurization (FGD):
- Lime spray dry absorber (SDA or dry FGD)
- Dry sorbent injection – Trona (DSI)
- SO_2 emission management

The Division also identified and examined additional control options for these units:
Lime or limestone-based (wet FGD)

NPS: We agree that CDPHE selected a reasonable suite of options.

Step 2: Eliminate Technically Infeasible Options

CDPHE: Flue gas desulfurization (FGD): The entire site is very congested, with limited access and limited room for major retrofits of new capital equipment.

- CENC determined dry FGD controls are not technically feasible as discussed above, therefore control effectiveness and impacts are not evaluated in this analysis. After the site visit, the Division concurred with this conclusion.
- Traditional wet FGD controls are possible considering that there is adequate space near the baghouse to allow for the installation of controls, but are eliminated based on other considerations within the five factors (i.e. energy and non-air quality impacts). Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Boilers 4 and 5.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CDPHE: In the Division's experience, 30-day SO_2 rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 5% for CENC Boilers 4 and 5 to determine control efficiencies and annual reductions.

NPS: We agree.

CDPHE: DSI: CENC asserts that the maximum SO_2 removal rate that can be achieved to be 65% SO_2 removal due to the small size of the boilers, and non-ideal gas/solids residence time. The Division adjusted this removal rate to 60%, based on other Colorado submittals and to be conservative since this technology is relatively novel.

NPS: We agree.

Step 4: Evaluate Impacts and Document Results—Cost of Compliance

CDPHE: *Wet FGD*: The significant cost issue associated with securing sufficient water supplies (a costly and scarce resource in the Front Range) to support a wet FGD control system along with the cost of disposing the sludge byproduct at an approved landfill since on-site storage is not an option. There are other costs and environmental impacts that the Division also considers undesirable with respect to wet scrubbers. For example, the off-site disposal of sludge entails considerable costs, both in terms of direct disposal costs, and indirect costs such as transportation and associated emissions. Refer to the energy and non-air quality impact section for the Division review regarding wet FGD controls for Boilers 4 and 5.

NPS: the costs described above can be objectively quantified and included in the cost estimation procedure.

CDPHE: DSI: PCC Industries provided the cost to CENC for the basic equipment required for Trona injection. . DSI requires less capital equipment, less physical space, and less medication to existing ductwork compared to a SDA system. However, reagent costs are much higher and, depending upon the absorbent and amount of sorbent injected, control efficiency is lower when compared to a SDA system. Additional costs for equipment redundancy, modifications to the facility's ash handling system, and increased transformer capacity were estimated by CENC based on the need to maintain continuous compliance with a short-term emission rate (30-day rolling) and past experience with retrofits at other CENC facilities. CENC derived total installed costs from the purchased equipment cost using USEPA factors (EPA's Cost Control Manual). Operating costs were based on estimated Trona requirements of 2.8 lb Trona per lb of SO_2 collected for 65 percent control. The theoretical minimum requirement is 2.4 lb Trona per lb of SO_2 collected. Detailed capital and annual cost data are presented in "CENC APCD Technical Analysis".

In reviewing CENC's DSI estimate, the Division found that the ratio of annual costs to the total capital costs for the control technology option projected by CENC to be higher than those projected by other facilities that were amortized over the same 20 year time frame. The annualized costs for DSI are about 35% of the total capital investment. The EPA found that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments6. However, CENC is a much smaller facility than the facilities in Arizona, New Mexico, and Oregon, which can significantly increase costs. CENC also clearly followed the Cost Control Manual methodology for estimating operation and maintenance costs. Therefore, the Division did not adjust CENC's cost estimates.

NPS: CENC has not properly applied the methods described in EPA's Control Cost Manual (Cost Manual). For example, as shown in our analysis **(see Appendix CENC DSI)**, CENC improperly included the costs for "Building enclosures/foundations" in the Purchased (Direct) Equipment Cost (PEC) category when it should have been categorized as a "Building" or "Site Preparation" cost. CENC then multiplied this inflated PEC by a factor of 2.5 instead of the 0.85 factor recommended by the Cost Manual. Had CENC properly applied the Cost Manual methods, it would have arrived at a Total Capital Investment of \$8.9 million instead of its inflated \$12.2 million estimate and an average control cost of \$1,710/ton.

CENC has also overestimated annual operating costs by assuming higher labor and maintenance costs and then compounding the error by improperly including those inflated costs in its estimate of "Overhead" costs. Our application of the Cost Manual method results in Direct Operating Costs of \$1 million/yr instead of the \$1.5 million estimated by CENC.

Finally, as a result of its inflated Total Capital Investment, CENC's estimate of Indirect Annual Cost was also inflated at \$2.1 million versus the \$1.3 million estimate generated from a proper application of the Cost Manual.

The ultimate result of CENC's overestimates is a Total Annual Cost of $3.9 million to control both boilers versus our $2.2 million/yr estimated derived from the Cost Manual.

CDPHE: The Division considers CENC's DSI costs to be within a reasonable cost range that is comparable to other Colorado facility submittals. CENC Boiler 4 is more expensive compared to other units because of the small size of the boiler and the increased difficulty of the retrofit. Therefore, the Division did not adjust CENC's DSI cost estimates.

NPS: It is difficult to understand how CDPHE concluded from its Table 7 that the 35 MW CENC boiler #4 could reasonably have a higher annual cost than the 51 MW Drake Unit #5.

CDPHE: SO_2 Emissions Management: CENC notes that the costs for implementing a SO_2 Emission Management Plan are based on essentially zero capital cost with increment variable operating costs based on the replacement of a portion of coal boiler capacity with natural gas as needed to reduce historical 24-hour SO_2 peaks.

<u>Step 4: Evaluate Impacts and Document Results—Energy and Non-Air Quality Impacts</u>

CDPHE: Traditional Wet FGD: Based upon its experience, and as discussed in detail below, the Division has determined that wet scrubbing has several negative energy and non-air quality environmental impacts, including massive water usage. This is a significant issue in Colorado, where water is a costly, precious and scarce resource. In the arid West, securing sufficient water supplies to support a wet FGD control system is a difficult undertaking that precludes other beneficial uses for such water. In Colorado, water law is based upon the doctrine of prior appropriation or "first in time - first in right," and the priority date is established by the date the water was first put to a beneficial use. Thus, depending upon whether and when a power plant first secured a water appropriation and whether such appropriation is adequate to supply the demand, there may be insufficient water appropriations available in some areas of the state, particularly in the Front Range, to accommodate the added demands of wet FGD controls. At a minimum, the water demands of wet FGDs will compete for what is already a scarce resource needed for Colorado's domestic, agricultural and industrial demands.

NPS: CDPHE's concerns appear to be speculative and unsupported. We also note the apparent inconsistency regarding the expressed desire to conserve water so that the brewery (that uses steam produced by CENC) can ship large quantities of water out of the area.

DSI: CENC documents additional collateral impacts of applying DSI include enhanced removal of halogenated acid gases, and reduced mercury capture in the baghouse. DSI ahead of the baghouse would contaminate the flyash with sodium sulfate, rendering the ash unsalable as a replacement for concrete and render it landfill material only. Currently, there is moderate removal of acid gases in the baghouse due to the alkaline nature of the flyash. The dry sorbent injection system does result in an ash by-product. This by-product does not require additional treatment before being deposited in a landfill. However, a study conducted by the Department of Energy found arsenic and methylene chloride in the ash, which could become a problem if more stringent regulations are imposed in the future. However, it is not known yet if these levels are considered hazardous or if the levels vary depending on the ash; therefore, this issue requires future research. Otherwise, the DSI does not have any negative energy or non-air quality related impacts. Thus, this factor (regarding DSI) does not influence the selection of controls.

NPS: CDPHE's concerns appear to be speculative and unsupported. CDPHE has presented no evidence that DSI would render the ash unsalable. Our discussions with DSI vendors indicates that this claim may be false. CDPHE should also explain why addition of DSI would increase arsenic and methylene chloride in the ash.

Step 5: Evaluate Visibility Results

NPS: CDPHE's modeling results indicate that DSI would yield a combined visibility improvement of 0.21 dv.

Step 6: Select BART Control

CDPHE: Although dry sorbent injection does achieve better emissions reductions, the added expense of DSI controls were determined to not be reasonable coupled with the low visibility improvement afforded.

NPS: It is not possible to determine how CDPHE arrived at the costs contained in its Tables 10 and 11 because the "CENC APCD Technical Analysis" evaluated the combined costs[1] of applying DSI to both boilers, while Tables 10 and 11 have somehow apportioned those costs between the two boilers. Nevertheless, our application of the Cost Manual resulted in an average control cost of $1,710/ton versus the $2,482 - $3,744 presented by CDPHE. We estimate that DSI would have a combined annual cost of $2.2 million, and cost-effectiveness of $10.7 million/dv. Our review of BART proposals and determinations by states and sources indicates that the average cost-per-deciview of improvement proposed is $14 - $18 million/dv. On that basis, DSI should be selected as BART.

Filterable Particulate Matter (PM10)

CDPHE: CENC Boilers 4 and 5 are each equipped with fabric filter baghouses to control PM/PM10 emissions. The Division has determined that the existing Boiler 4 and 5 fabric filter baghouses and the existing regulatory emissions limits of 0.07 lb/MMBtu (PM/PM10) represent the most stringent control option. The units are exceeding a PM control efficiency of 95%, and the control technology and emission limits are BART for PM/PM10. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for PM/PM10 is not needed for CENC Boilers 4 and 5.

NPS: The proposed limits should more closely reflect the demonstrated capabilities of these baghouses to meet lower limits (e.g., 0.015 lb/mmBtu).

Nitrogen Oxide (NOx)

Step 1: Identify All Available Technologies

CDPHE: CENC identified four NOx control options:

- Selective catalytic reduction (SCR)
- Selective non-catalytic reduction (SNCR)
- Combustion modifications/low-NOx burners (LNB)

[1] We agree with combining the cost evaluation because of the potential of shared equipment and costs between the two boilers.

- Low-NOx burners + Separated Overfire Air (LNB+SOFA)

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

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Fuel Switching – Natural Gas
- Coal reburn +SNCR

NPS: CDPHE should have included Ultra-low NOx burners (ULNBs) in its suite of options. As CDPHE noted in is BART analysis for the Martin Drake facility, "Burner designs have improved in recent years to improve flame stability and combustion control schemes for increased NOx emission reductions with these ultra-low NOx burners." CDPHE improperly excluded ROFA with Rotamix® that, according to Minnesota Power, can achieve up to 68% NO_X control on its coal-fired 75 MW Taconite Harbor Unit #3.

Step 2: Eliminate Technically Infeasible Options

CDPHE rejected:

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

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CDPHE: LNB/LNB+SOFA: CENC estimated that low-NOx burners (Alstom's Low NOx Concentric Firing System (LNCFS) System) are capable of reducing NOx emissions by approximately 10 – 12%, which results in annual emission rates of 0.45 and 0.30 lb/MMBtu for Boilers 4 and 5, respectively. A similar Colorado facility with installed LNB achieves approximately 0.35 – 0.38 lb/MMBtu and estimates an additional 20% reduction if OFA is installed to achieve 0.28 – 0.30 lb/MMBtu. These same burners with Separated Overfire Air were estimated to reduce NOx emissions by 30 – 35%, resulting in an annualized estimated 0.32 and 0.24 lb/MMBtu for Boilers 4 and 5 respectively.

SNCR/SNCR+LNB/SOFA: CENC noted in the original BART submittal (July 2006) that SNCR achieves 30 – 50% control, which is consistent with EPA's SNCR Air Pollution Control Technology Fact Sheet and the Division's experience. However, when CENC calculated SNCR control efficiency in the November 2009 submittal, it was assumed that LNB+SOFA would be installed beforehand. CENC estimated that SNCR would reduce NOx emissions 40% with LNB+SOFA installed, for resultant emission rates of 0.19 lb/MMBtu and 0.17 lb/MMBtu for Boilers 4 and 5, respectively. This equates to 62 – 67% reduction depending on the boiler, which is consistent with EPA's AP-42 emission factor tables (50 – 80%). Therefore, the Division concurs with CENC's control efficiency estimates for LNB+SOFA+SNCR.

The Division conducted a separate analysis regarding stand-alone SNCR installation (without LNB+SOFA installation) for comparison purposes. The Division did not use CENC's original estimate of 40% reduction for SNCR. Instead, the Division estimated control efficiency based on a variety of information, including similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study to conservatively approximate that the CENC boilers can achieve 30% control when SNCR is applied.

NPS: As for "EPA's SNCR Air Pollution Control Fact Sheet," that 2002 document is out-of-date but still estimates that SNCR can achieve 30% - 50% NO_X control efficiency. We suggest that a more appropriate estimate can be found where the North Dakota Department of Health is proposing that the 188 MW Stanton Generating Station install SNCR with an estimated 45% NO_X control efficiency.

SCR: CENC, via their vendor, estimates that each boiler will be able to achieve a 0.06 lb/MMBtu emission rate on a 30-day rolling average. CENC estimated control efficiencies on the assumption that LNB+SOFA will already be installed. However, this will not change the overall SCR resultant emission rate.

The Division adjusted this emission rate to be 0.07 lb/MMBtu to be consistent with other Colorado facility submittals and literature review. This adjusted rate equates to 86% control for Boiler 4 and 80% control for Boiler 5. These control efficiencies are consistent with EPA's AP-42 emission factor tables, which estimate SCR as achieving 75 – 85% NOx emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.

NPS: As we demonstrate in much greater detail in our general comments,[2] there is **overwhelming evidence to support the lower (0.06 lb/mmBtu) "target"** for SCR used by CENC. The "recent" studies cited by CDPHE are vintage 1998 and 2005, and do not support CDPHE's upward "adjustment" of the lower NO_X rate used by CENC.

Step 4: Evaluate Impacts and Document Results

LNB/LNB+SOFA: CENC contracted Alstom Power to determine total installed costs for low-NOx burners and separated overfire air. In reviewing CENC's estimates, the Division found that the ratio of annual costs to the total capital costs for LNB/LNB+SOFA projected by CENC to be slightly higher than those projected by other facilities that were amortized over the same 20 year time frame.

The cost effectiveness for SNCR on Boilers 4 and 5 is about $2,900 and $3,350 per ton, respectively. Although CENC's estimates are greater than these ranges, the small size of the boilers as well as the difficulty of the retrofit leads the Division to the conclusion that CENC's cost estimates for SNCR are reasonable.

NPS: CDPHE has provided no evidence to support its speculation regarding any special problems associated with installing SNCR at CENC. Instead, as recommended by CDPHE and by the BART Guidelines, we are providing SNCR cost estimates based upon methods described by EPA's Control Cost Manual (Cost Manual). Our analyses, summarized below **(and provided in Appendix CENC SNCR)** show that, even at the low 30% control efficiency estimate used by

[2] We are providing information that supports use of 0.05 lb/mmBtu as an annual NO_X emission rate.

CDPHE, SNCR can reduce NO_X emissions at $800 - $1,300/ton, which is much less than the $2,900 - $3,350/ton estimated by CDPHE.

SNCR Cost-benefit Analysis

Unit	4	5	
Controlled emissions (lb/mmBtu)	0.35	0.24	CDPHE report
Controlled Emissions (tpy)	491	487	calculated
Emissions Reduction (tpy)	206	211	calculated
Capital Cost	$ 1,305,459	$ 1,686,485	OAQPS Control Cost Manual
Capital Cost ($/kW)	$ 37	$ 26	calculated
Annualized Cost	$ 224,859	$ 255,278	OAQPS Control Cost Manual
Cost-Effectiveness ($/ton)	$ 790	$ 1,255	OAQPS Control Cost Manual

CDPHE: SCR: CENC contracted Lutz, Daily, & Brain (LDB) to develop a capital cost estimate. On both boilers, it was determined that the economizers must be moved because there is very little space between the air heater outlet and the current economizer configuration, adding to the capital cost. CENC's cost estimates are higher than this range, but the small size of the boilers as well as the difficulty of the retrofit leads the Division to the conclusion that CENC's cost estimates for SCR are reasonable.

NPS: Our review of the SCR cost estimates provided by CDPHE leads us believe that TCI costs are overestimated when compared to the Cost Manual's 1.41:1 ratio of TCI to Total Direct Cost. However, when we apply the Cost Manual method to estimate Direct and Indirect Annual costs, we see much greater evidence that these critical annual costs have been overestimated. Therefore, we are providing SCR cost estimates summarized below **(and provided in Appendix CENC SCR)** based upon methods described by the Cost Manual.

SCR Cost-benefit Analysis

Unit	4	5	
Controlled emissions (lb/mmBtu)	0.05	0.05	calculated
Controlled Emissions (tpy)	58	81	calculated
Emissions Reduction (tpy)	515	476	OAQPS Control Cost Manual
Capital Cost	$ 18,741,759	$ 27,006,619	OAQPS Control Cost Manual
Capital Cost ($/kW)	$ 535	$ 415	calculated
Annualized Cost	$ 2,195,393	$ 3,115,175	OAQPS Control Cost Manual
Cost-Effectiveness ($/ton)	$ 4,265	$ 6,540	OAQPS Control Cost Manual

Application of the Cost Manual methods shows that SCR can reduce NO_X emissions at $4,265 - $6,540/ton, which is much less than the $8,150 - $11,764/ton estimated by CDPHE.

<u>Step 5: Evaluate Visibility Results</u>

NPS: We note that CDPHE has estimated that LNB+SOFA on Boiler #4 will yield a 0.08 dv improvement at Rocky Mountain National Park, while LNB+SOFA+SNCR on Boilers #4 & #5 will yield 0.11 and 0.25 dv improvements, respectively. SCR on Boilers #4 & #5 will yield 0.18 and 0.31 dv improvements, respectively.

Step 6: Select BART Control

CDPHE: The current regulatory requirements for Boiler 4 are amended to clarify that the current regulatory NOx BART control for Boiler 4 is actually low NOx burners with *separated* overfire air as specified in CENC's original BART application. Based upon its consideration of the five factors summarized herein, the state has determined that NOx BART for Boiler 5 is low NOx burners, separated over-fire air and selective non-catalytic reduction.

NPS: We note that the costs/dv estimated by CDPHE for its proposed BART options are $8.5 million for Boiler #4 and $7.1 million for Boiler #5. Although CDPHE rejected LNB+SOFA+SNCR on Boiler #4, its estimated cost-effectiveness of $12.5 million/dv is lower than the $14 - $18 million/dv average cost-per-deciview of improvement proposed by states and sources.

We also note that the cost/ton shown for LNB+SOFA+SNCR for Boiler #4 is $3,729, which is lower than the $4,918/ton CDPHE estimated for BART for Boiler #5. Addition of SNCR to CDPHE's BART proposal for Boiler #4 would result in greater NO_X reductions at a lower annualized cost than the CDPHE BART proposal for Boiler #5.

Finally, SCR is cost-effective at $12.2 and $10.0 million/dv for Boilers #4 and #5, respectively, when one considers visibility benefits. We believe that SCR should be BART for both Boilers #4 and #5.