Best Available Retrofit Technology (BART) Analysis of Control Options For Colorado Energy Nations, Golden, Colorado

I. Source Description

Owner/Operator: Colorado Energy Nations Company (CENC) (formerly Trigen Colorado Energy Corporation)
Source Type: Steam Generating Unit
Boiler Type(s): Boiler 4 – Pulverized Coal Dry-Bottom Tangentially-Fired (SCC: 10200222 for coal)
Boiler 5 – Pulverized Coal Dry-Bottom Tangentially-Fired (SCC: 10200222 for coal)

The CENC facility is located in Jefferson County on 10th Street in the town of Golden, Colorado. Figure 1 below provides an aerial perspective of the CENC site. The two large buildings are separated by Clear Creek to the south and US Highway 58 borders the northern side of the CENC site. The large building to the north of CENC and south of Highway 58 is the Coors Brewery.

Figure 1: CENC facility Aerial Perspective

The CENC facility 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/PM_{10} by separate fabric filter baghouses, which were installed at the time of construction for each boiler. The boilers were installed as follows:

- Boiler 1 – 1962
- Boiler 2 – 1962
- Boiler 3 – 1962 – updated to coal in 1981
- Boiler 4 – 1974 – last modification in 1975
- Boiler 5 – 1979 – reached full capacity in 1980

No coal processing is performed on-site. The coal is received ready for feed to the boilers. 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. There is also one Detroit Diesel engine (<100 HP) at the facility for maintenance of equipment and/or backup operation of air compressors that was installed prior to 1970. This engine is tested weekly. The Coors Brewery currently contracts for the purchase of the total electricity and steam output.

Boilers 4 and 5 are considered BART-eligible, being industrial boilers with the potential to emit 250 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}), and commenced operation in the 15-year period prior to August 7, 1977. Initial air dispersion modeling performed by the Division demonstrated that the CENC facility contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Trigen (now CENC) submitted a BART Analysis to the Division on July 31, 2006. CENC also provided information in "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado" Submittal provided on November 16, 2009 as well as additional information upon the Division's request on February 8, 2010 and May 7, 2010. These documents are all provided as "CENC BART Submittals". Table 1 depicts technical information for each BART-subject boiler at the CENC facility.

Table 1: CENC Facility BART-eligible Emission Controls and Reduction (%)

	Unit B004	Unit B005
Placed in Service	1975	1979
Boiler Rating, MMBtu/Hr for coal	360	650
Electrical Power Rating, Gross Megawatts	35	65
Description	Combustion Engineering Model CE-VU40 360 MMBtu/hr (coal), tangential fired, firing coal, natural gas, #2 fuel oil, ethanol, on-site generated on-spec used oil and sludge from WWTP	Combustion Engineering Model CE-VU40 650 MMBtu/hr (coal), tangential fired, firing coal, natural gas, #2 fuel oil, ethanol, on-site generated on-spec used oil and sludge from WWTP
Air Pollution Control Equipment	Wheelabrator-Frye Model 264 fabric filter baghouse with 8 compartments	Carter Day fabric filter baghouse with 12 modules
Monitoring Equipment	COM CEMs for SO_2, NO_x, CO_2, and stack gas	COM CEMs for SO_2, NO_x, CO_2, and stack gas

Emissions Reduction (%)	NO_x – None SO_2 – None PM/PM_{10} – 99+%	NO_x – None SO_2 – None PM/PM_{10} – 99+%

II. Source Emissions

CENC estimated that a realistic depiction of anticipated annual emissions for Boilers 4 and 5, or "Baseline Emissions", to be conservative, was the maximum historical (2000 – 2005) 12-month (rolling) emissions experienced in the July 31, 2006 analysis. CENC also provided 2-year annual average emissions for comparison purposes.

Several years have passed since the original BART submittal, in which the Division has updated modeling and technical analyses. Therefore, the Division 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. The baseline emissions are used as the basis for estimating annual emission reductions for the various control technologies evaluated and determining the annualized costs to achieve those reductions. . The Division verified these emissions using Colorado's Air Pollutant Emission Notices and EPA's CAMD database as applicable. These emissions are summarized in Table 2.

Table 2: CENC Boilers 4 and 5 Baseline Emissions

Pollutant	Boiler 4		Boiler 5	
	Annual Emissions* (tpy)	30-day rolling average emissions** (lb/MMBtu)	Annual Emissions* (tpy)	30-day rolling average emissions** (lb/MMBtu)
NO_x	600	0.50	691	0.34
SO_2	781	0.64	1,406	0.71
PM_{10}	11	0.003***	18	0.01***

*Using most recent three calendar years (CEMs data).
**The Division calculated 30-day rolling average rate (lb/MMBtu) from the most recent three calendar years (CEMs data) based on maximum daily reported data for each unit for NO_x and SO_2 emissions. Days with zero emissions/heat input were not included in these averages.
***The PM_{10} emission rate is determined from calculating the maximum heat input and annual operating hours.

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. Both units are subject to Colorado Regulation 6 Part A and NSPS 40 CFR Subpart D.

III. Units Evaluated for Control

As documented by CENC, these boilers fire low sulfur, high heating value bituminous coal from western Colorado. The specifications for the coal are listed in Table 3.

Table 3: Coal Specifications (2006 – 2008 Averaged APEN data)

	Specifications		
Emission Unit	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
B004	11,703	0.42	9.14
B005	11,833	0.42	9.17

Table 1 lists the units at the CENC facility that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CEMs data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal.

Table 4: Uncontrolled emission factors for CENC BART-eligible sources

Emission Unit	Pollutant	Fuel		
		Natural Gas (lb/MMscf)	Coal (bituminous) (lb/ton)	#2 Fuel Oil (lb/Mgallons)
Boiler 4 & Boiler 5	NO_x	280	8.4	24
	SO_2	0.6	35 x %S = 14.7*	157 x %S = 67.5*
	PM/PM_{10}	7.6	PM – 10 x %A = 91.4** PM_{10} – 2.3 x %A = 21.0**	PM – 2 PM_{10} – 1

*%S = % of sulfur present in coal supply. For example, 35 x 0.42 = 14.7
**%A = % of ash present in coal supply. For example, 10 x 9.14 = 91.4

IV. BART Evaluation of Boiler 4 and Boiler 5

A. Sulfur Dioxide (SO_2)

Step 1: Identify All Available Technologies

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)
- Emission limit tightening (no control)

Step 2: Eliminate Technically Infeasible Options

FGD: Flue gas desulfurization removes SO_2 from flue gases by a variety of methods. Wet scrubbing uses a slurry of alkaline sorbent, either limestone or lime, to scrub the gases. The most common dry FGD system is a lime spray dry absorber uses that slaked lime slurry sprayed into the flue gas, which is subsequently dried by the heat of the flue gas, and then collected in a particulate control device. Generally, FGD control systems need to be located in close proximity to the boiler exhaust gas stream to prevent condensation (e.g. cooling of the exhaust gases) that result in acidic precipitation in the duct which results in corrosion issues.

Wet FGD: Wet FGD control systems must be located after the baghouse because the moist plume resulting from the wet scrubber system would create baghouse plugging issues if the control is placed ahead of the baghouse. Each absorber tower requires a similar "foot print" area, along with additional space for support equipment access, slurry preparation, mixing, associated tanks, dewatering and a chimney.

Dry FGD: Dry FGD systems are commonly known as spray dry absorbers (SDA) or lime spray dryers (LSD), and currently make up about 12% of FGD systems at U.S. power plants[1]. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. Additionally, Controlling SO_2 Emissions: A Review of Technologies[2] evaluates various SO_2 control technologies and shows that for low-sulfur coal applications, LSDs can meet comparable emission rates to wet systems.

A SDA system must be located before the boiler flue gases enter the baghouse. Each reactor vessel requires a "foot print" area comprising about 2,000 to 4,000 square feet (depending on volume of flue gas treated) along with additional space for support equipment access, slurry preparation, mixing and associated tanks.

The plant is bounded to the north by US Highway 58 and Coors Brewery buildings, to the west by 12th street and a small parking, to the east by Coors rail yard lots, and the south by Clear Creek and the Coors Brewery. Train tracks also bound the facility to the north and east. Figure 1 illustrates these boundaries. Figure 2, depicting a detailed view of the boilers, respective baghouses, and available spaces for FGD systems, indicates that available physical space is severely constrained at the CENC facility, due to locations as well as pollution control retrofits for particulate matter. The entire site is very congested, with limited access and limited room for major retrofits of new capital equipment. CENC asserts that in order to allow sufficient residence time for evaporation and reaction with SO_2, the design gas residence time in a SDA is approximately 10 seconds. For Boilers 4 and 5, a SDA vessel for each boiler, not including other associated equipment, would be approximately 35 feet in diameter by 60 feet high. In addition, in order to provide high reagent utilization, the unreacted lime mixed with ash form the baghouse must be recycled. This would increase solids loading in each baghouse by a factor of 3 and require extra baghouse capacity and a complete reconstruction of the ash handling system. Subsequently, CENC determined that it is not technically feasible to install dry FGD systems on either Boilers 4 or 5 (B004/B005).

In 2007, the Division conducted an on-site visit to determine the technical feasibility of potential SO_2 controls on Units 4 and 5. The Division noted:

[1] Electric Power Research Institute: A Review of Literature Related to the Use of Spray Dryer Absorber Material – Production, Characterization, Utilization Applications, Barriers, and Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environmental Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg. v.

[2] Srivastava, R.K. Controlling SO2 Emissions: A Review of Technologies. U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-00/093 (NTIS PB2001-101224), 2000.

- 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.

Figure 2: Aerial Zoom of CENC Facility

DSI: Dry sorbent injection involves the injection of typically a sodium based reagent, either the mineral trona (sodium sesquicarbonate) or refined sodium bicarbonate, into the flue gas. The injected reagent reacts with the SO_2 present in the flue gas to create sodium sulfate, which is then collected in the particulate control device, in the case of CENC. CENC asserts that the flue gas temperatures present upstream of the boiler airheaters are in the appropriate range to allow for DSI application. A very important factor in DSI application is the ability for the boiler's particulate control device to accommodate the added particulate loading of the DSI reagent in addition to the flyash loading. CENC's preliminary review indicates that even with the added loading of DSI reagent, the CENC baghouses would be operating within the design specification for particulate loading, but the ash collection system(s) would require modifications. The flue gas is not cooled nor saturated with water, so reheating of desulfurized flue gas is not required. No gas-sorbent contacting vessel is required to be installed. 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. Lime, soda ash, and Trona (sodium sesquicarbonate) are possible. Lime is the least reactive reagent resulting in low efficiencies even at high injection rates. Trona is a very reactive reagent that can be used to achieve a range of efficiencies depending on the amount of sorbent injected, and would likely be the chosen reagent.

Due to variability of boiler configurations, coal composition, NO_x to SO_2 ratios, and other factors, it is difficult to arrive at a precise estimate of the maximum SO_2 removal rate that is achievable while minimizing the brown plume condition. However, based on literature review, CENC estimated the maximum SO_2 removal rate that can be achieved while minimizing the creation of the brown plume condition to be 65% SO_2 removal. In practical application, a higher SO_2 removal rate may be possible, while it is also possible that a lower SO_2 removal rate may be necessary to limit the brown plume formation. This determination would require actual SO_2 removal real-time testing. CENC consulted with PPC Industries to determine the feasibility and emission reduction potential associated with installing DSI-Trona controls. Therefore, DSI-Trona is technically feasible for the CENC facility Boilers 4 and 5.

SO_2 Emissions Management: CENC is subjected to variations in as-received coal sulfur content. Figure 3 provided by CENC shows that there are clearly historical (2000 – 2005) short-term peaks in SO_2 emissions that can be attributed to infrequent deliveries of high-sulfur coal. CENC has no capability or additional storage space on site to store coal or to blend with other lower sulfur coals in order to manage SO_2 emissions to lower levels, and has not had a regulatory need to do so. Once delivered, the facility has no choice but to use the coal delivered before a subsequent lower sulfur shipment can be obtained and burned.

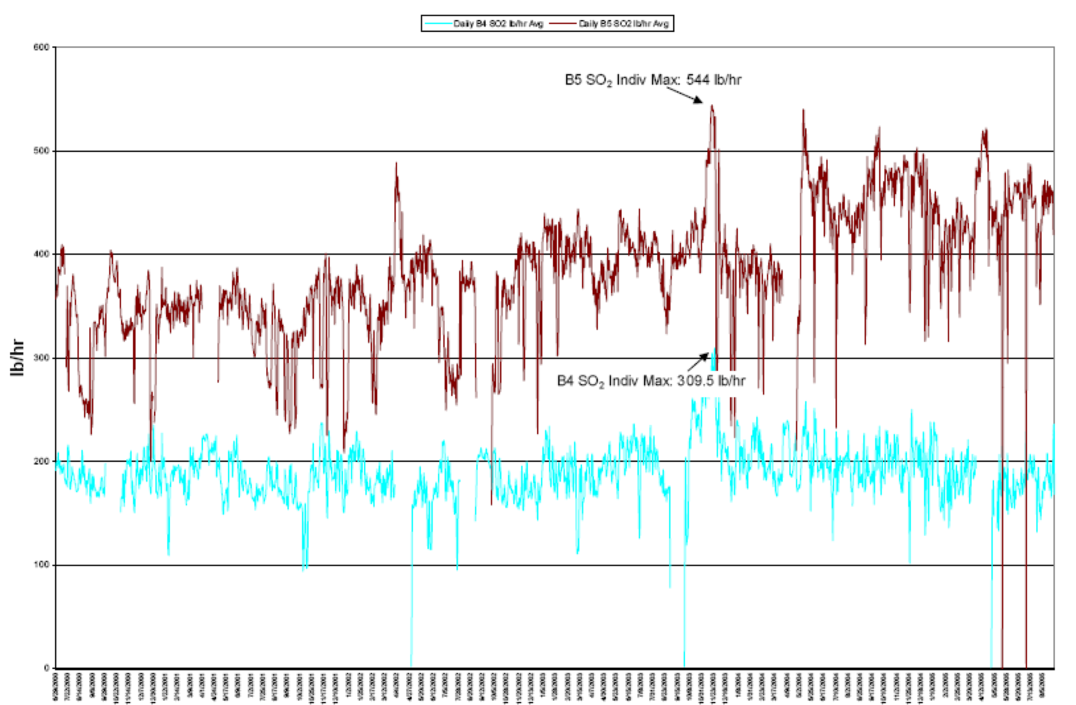

Figure 3: Boilers 4 and 5 SO_2 lb/hour daily average (2000 - 2005)

Using alternative approaches to operations management, CENC proposes a new, enforceable permit limit to reduce peak lb/hr SO_2 emissions. CENC can employ a variety of options to reduce emissions: dispatch natural gas-fired capacity, reduce total system load, and/or reduce coal firing rate to maintain a new peak SO_2 limits. Since these two boilers already have CEMs and stack flow monitors installed, the CEMs could be used to demonstrate continuous compliance. CENC proposes reducing peak levels with limits at 280 lb/hr for Boiler 4 and 500 lb/hour for Boiler 5 on a 24-hour average basis. This option is technically feasible for Boilers 4 and 5.

Emission limit tightening: The Division and CENC conducted technical analyses of sulfur % and heat content in historical coal supplies to determine whether the current SO_2 emission limit could be more stringent based on actual emissions (2006 – 2008) from the units. This option is technically feasible for Boilers 4 and 5.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CENC provided the Division annual average control estimates. 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.

The Division has reviewed the data supplied by CENC as well as other control techniques applied to pulverized coal boilers. A Division review of the EPA's RBLC revealed recent BACT SO_2 determinations range from 0.06 – 0.167 lbs/MMBtu. The Division narrowed down this range depending on the averaging time, permit type, facility size, and fuel type. This narrowed range is 0.095 – 0.161 lbs/MMBtu, with an average of 0.119 lbs/MMBtu rounded to 0.12 lbs/MMBtu. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details. The Division notes that for CENC, any RBLC determinations apply for DSI only, since SO_2 emissions management is unit-specific.

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[3] and to be conservative since this technology is relatively novel.

SO_2 Emissions Management: Table 5 summarizes current Title V permit limits and projected emission reductions using CENC's proposed limits.

[3] Colorado Springs Utilities, 2010. "RE: Question Regarding the Application of Dry Sorbent Injection to Martin Drake Power Plant Unit 5." Submitted to the Colorado Air Pollution Control Division on May 10, 2010.

Table 5: CENC Boiler 4 and 5 Current vs. Proposed SO_2 Permit Limits and Emissions Reduction

Unit	Current Title V SO_2 permit limits	Actual Emissions (2000 – 2005)	Actual Emissions (2006 – 2008)	CENC proposed SO_2 limits
Boiler 4	1892.0 tons/year (approx. 432 lb/hour)	911.8 tons/year (approx. 208 lb/hour)	780.6 tons/year (approx. 178 lb/hour)	280 lb/hour (CEM 24-hr rolling avg.)
	Coal – 1.2 lb/MMBtu (CEM 3-hr rolling avg.)			
	Fuel Oil – 0.8 lb/MMBtu (CEM 3-hr rolling avg.)			
Boiler 5	3,416.0 tons/year (approx. 780 lb/hour)	1,954.7 tons/year (approx. 446 lb/hour)	1,406.0 tons/year (approx. 321 lb/hour)	500 lb/hour (CEM 24-hr rolling avg.)
	Coal – 1.2 lb/MMBtu (CEM 3-hr rolling avg.)			
	Fuel Oil – 0.8 lb/MMBtu (CEM 3-hr rolling avg.)			
Combined limit	4,888.0 tons/year (approx. 1,116 lb/hour) (PM_{10} SIP Agreement)	2,866.5 tons/year (approx. 655 lb/hour)		780 lb/hour (CEM 24-hr rolling avg.)

*Refer to pages A-31, A-34, and A-35 of CENC BART Submittal (July 31, 2006) for detailed SO_2 emission documentation.

Emission limit tightening: Since emission limit tightening is based on actual data, there will be minimal, if any, reductions from baseline period (2006 – 2008) SO_2 emissions. The Division found that the maximum 30-day rolling emission rate was 0.80 lb/MMBtu for Boiler 4 and 0.9 lb/MMBtu for Boiler 5. However, for these small industrial boilers with very limited coal storage capacity, the Division and CENC agree that reviewing sulfur % and heat content is a better basis for determining an appropriate SO_2 emission limit. CENC submitted supplemental information on October 26 and November 10, 2010 to support this methodology. Refer to Table 6 for more details.

Table 6: Coal Supply Analysis for SO2 Emission Limit

	2006 – 2008
Minimum (Btu/lb)	9.997
Maximum (% Sulfur) (30-day period)	0.52
Theoretical lb/MMBtu	
Boiler 4 Sulfur to SO_2 conversion averages at 99%*	1.03 (rounded to 1.0)
Boiler 5 Sulfur to SO_2 conversion averages at 100%*	1.04 (rounded to 1.0)

*CEMs data vs. theoretical

Based on the boiler sulfur to SO_2 conversions, the appropriate emission limit based on actual fuel supply data for the baseline period is 1.0 lb/MMBtu (30-day rolling average). This option serves as assurance that CENC will be able to both continually comply with an appropriate emission limit while simultaneously eliminating future potential emission increases.

Table 7summarizes each available technology and technical feasibility for SO_2 control.

Table 7: CENC Boilers 4 and 5 SO_2 Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)

Wet FGD	52-98%, median 90%[4]	Y
Dry FGD (SDA)	70-90% (CENC)	Y
DSI (Trona)	~60%	Y
SO_2 Emissions Management	30%	Y
Emission Limit Tightening	Minimal	Y

Step 4: Evaluate Impacts and Document Results

Factor 1: Cost of Compliance

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.

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".

The Division compared CENC's costs for DSI to other Colorado facilities similar in size that analyzed DSI, shown inTable 8.

Table 8: DSI Cost Comparisons

Facility & Unit	Size (MW)	Annualized Costs ($/year)	Cost Effectiveness ($/ton)	Ratio ($/kW)
Colorado Energy Nations – Boiler 4	35	$1,766,000	$3,774	$50.46
Colorado Springs Utilities – Drake Unit 5	51	$1,746,172	$2,293	$34.33

[4] U.S. EPA, 2000. "Controlling SO_2 Emissions: A Review of Technologies." Prepared by Ravi K. Srivastava for the U.S. Environmental Protection Agency, Office of Research and Development. Office of Research and Development. Washington, D.C. 20460.

Colorado Energy Nations – Boiler 5	65	$2,094,000	$2,485	$32.22
Colorado Springs Utilities – Drake Unit 6	85	$2,910,287	$1,741	$34.24

The Division considers CENC's DSI costs to be within a reasonable cost range that is comparable to other Colorado facility submittals.[5] 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.

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. The emission level projected for this alternative was derived from the analysis of historical emission level variability detailed in Figure 3.

The Division verified CENC's calculated costs for SO_2 Emission Management based on SO_2 hourly CEMs data (06/29/2000 through 01/04/2006), the amount of curtailment that will be required, and average natural gas costs ($10/MMBtu). 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 investments[6]. 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.

Emission limit tightening: There are no costs associated with this option. This option is considered equivalent to the "baseline" row in the tables below, and is not considered as a separate cost option.

Table 9, Table 10,Table 11, and Table 12 depict controlled SO_2 emissions and control cost comparisons.

Table 9: Boiler 4 Control Resultant SO_2 Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	780	0.64	0.74

[5] ENSR, 2006. BART Analysis for the TriGen Colorado Energy Corporation Facility in Golden, Colorado. Prepared for Trigen. Document No: 10279-017-700.

[6] Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.

SO_2 Emissions Management	0.13	767	0.64	0.74
DSI - Trona	60	312	0.26	0.30

Table 10: Boiler 5 Control Resultant SO_2 Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,406	0.71	0.82
SO_2 Emissions Management	0.06	1,448	0.71	0.82
DSI - Trona	60	562	0.29	0.33

Table 11: Boiler 4 SO_2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)*	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
SO_2 Emissions Management	1.0	$44,299	$43,690	$43,089
DSI - Trona	468	$1,766,000	$3,744	-$85

Table 12: Boiler 5 SO_2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
SO_2 Emissions Management	0.8	$65,882	$78,095	$92,572
DSI - Trona	844	$2,094,000	$2,482	-$90

Energy and Non-Air Quality Impacts

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. Wet scrubbers consume approximately 23% more water than LSD scrubbers, depending on boiler size.[7]

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. On-site storage of wet ash is an increasing regulatory concern, as evidenced by the recent Tennessee Valley Authority spill. In addition, the steam plume resulting from a wet FGD control system in such a confined creek bed will produce a noticeable cloud that will hang over a densely populated area (City of Golden). The Division has received complaints regarding the more visible plumes associated with wet scrubbing; a potential irony in light of the visibility issues at the heart of the BART program. The Division largely focused its BART SO_2 control technology consideration on commercially available once-through dry FGD controls, specifically, "lime spray dryers" (LSD), that have an established record of reliable performance on boilers burning low-sulfur coal. Generally, wet FGD controls can achieve a higher level of SO_2 control on a percent capture basis that exceeds the capabilities of LSDs but, as noted above, there are a number of non-air quality and other environmental impacts including increased water usage, sludge disposal and wet plume issues that often overshadow any incremental improvement in SO_2 emission reductions. Recent PSD applications in Colorado have demonstrated lime spray dryer systems to be BACT.

The Division finds that the non-air quality environmental impacts outweigh the visibility benefits from this technology. Therefore, the State has eliminated this option as BART.

SO_2 Emissions Management: The Division has determined that there are not any negative energy or non-air quality related impacts related to the proposed SO_2 emission management scenario.

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,[8] 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.

---

[7] 2008. "Revised BART Analysis for Unit 1 & 2 Gerald Gentleman Station Sutherland, Nebraska: Nebraska Public Power District." Prepared by: HDF 701 Xenia Avenue South, Suite 600 Minneapolis, MN 55416 With control technology costs provided by: Sargent & Lundy.

[8] Department of Energy, 2001. LIFAC Sorbent Injection Desulfurization Demonstration Project: A DOE Assessment. U.S. Department of Energy: National Energy Technology Laboratory. P.O. Box 880, 3610 Collins Ferry Road Morgantown, WV 26507-0880. http://www.netl.doe.gov/technologies/coalpower/cctc/resources/pdfs/lifac/LIFAC_PPA.pdf

Emission Limit Tightening: There are no known non-air quality or energy impacts associated with emission limit tightening. Thus, this factor does not influence the selection of this option.

Remaining Useful Life

CENC asserts that there are no near-term limitations on the useful 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.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 13 shows the number of days pre- and post-control. Table 14 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[9], 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_2 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_x emissions at 0.07 lb/MMBtu (SCR control) and SO_2 emissions (DSI control) at 0.258 lb/MMBtu for Boiler 4 and 0.286 lb/MMBtu for Boiler 5.

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.

Table 13: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

SO_2 Control Scenario	Unit(s)	SO_2 Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hr	4	0.90	Rocky Mountain	33	---	---	10	---	---
	5	0.98							

[9] Colorado Air Pollution Control Division, Technical Services Program, 2010. “Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis.”

DSI	4	0.258	National Park	33	29	4	10	7	3
	5	0.286		33	28	5	10	7	3
Combo	4&5	0.361 0.392		33	3	30	10	0	10

Table 14: Visibility Results – SO_2 Control Options

Scenario	Boiler(s)	SO_2 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-hr	4 5	0.90 0.98	1.07	---	---	---
DSI	4	0.258	0.99	0.08	8%	$21,802,469
	5	0.286	0.94	0.13	12%	$16,752,000
Combo	4 5	0.361 0.392	0.28	0.79	74%	$18,393,225

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that SO_2 BART is the following SO_2 emission rates:

CENC Boiler 4: 1.0 lb/MMBtu (30-day rolling average)
CENC Boiler 5: 1.0 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved without additional control technology. 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.

B. Filterable Particulate Matter (PM_{10})

CENC Boilers 4 and 5 are each equipped with fabric filter baghouses to control PM/PM_{10} emissions. Baghouses, or fabric filters, operate on the same principle as a vacuum cleaner. Air carrying dust particles is forced through a cloth bag. As the air passes through the fabric, the dust accumulates on the cloth, providing a cleaner air stream. The dust is periodically removed from the cloth by shaking or by reversing the air flow. The layer of dust, known as dust cake, trapped on the surface of the fabric results in high efficiency rates for particles ranging in size from submicron to several hundred microns in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

Colorado Operating Permit 96OPJE143 Conditions 3.5 and 4.4 require Boilers 4 and 5 to each meet a PM/PM_{10} emission limit of 0.1 lb/MMBtu. Additionally, Condition 18.1 mandates that each baghouse be equipped with an operating pressure drop measuring device and outlines the Continuous Opacity Monitor requirements.

Table 15 shows the most recent stack test data (August 23, 2007 for Boiler 4 and October 10, 2007 for Boiler 5). It is important to note that the most recent stack test, which at a minimum, occurs every five years in accordance with Colorado Operating Permit 96OPJE143 Condition 18.2, and more frequently depending on the results, demonstrates that these baghouses are meeting >95% control.

Table 15: CENC 2007 Stack Test Results

Pollutant	Boiler 4 (lb/MMBtu)	Boiler 5 (lb/MMBtu)
Filterable PM_{10}	0.013	0.012
PM_{10} Control efficiency	98.4%	98.3%

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations ranging from 0.010 – 0.1 lbs/MMBtu, which are dependent on a number of factors, including PSD netting, EGU type and age, coal type, and adjacent controls. The current stack test results above are well below the range of recent BACT determinations. While determinations made by other states do not dictate the emissions rate choice made by the Division, they do provide information on the range to validate the emissions rate chosen by the Division. Refer to "Division RBLC Analysis" for more details regarding BACT determinations.

These boilers are subject to National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, more commonly known as the Boiler MACT, which was proposed on June 4, 2010.[10] As currently proposed, the boilers will be subject to a PM limit of 0.02 lb/MMBtu (monthly average).[11]

Other commercial EGUs must meet a PM limit of 0.03 lb/MMBtu, so the Division evaluated the possibility of tightening the existing PM limit of 0.07 lb/MMBtu on CENC units 4 and 5 based on the idea that there may not be any cost associated with a tighter limit. However, compliance with the PM limit is demonstrated through periodic performance tests, where compliance is unknown until the test results are evaluated. Consequently, a tighter emission limit has the effect of increasing the likelihood of non-compliance without any possibility of remedy until after the test is complete. This dilemma is further complicated by the presumption that any non-compliance is assumed backward in-time until the last performance test indicating compliance. Thus a tighter PM limit has the effect of forcing sources into more frequent performance testing to ensure that any unanticipated non-compliance is of shorter duration and thus less costly for any associated enforcement actions. Consequently, a tighter emission limit does have an associated increase in costs to the source.

Furthermore, the Division conducted sensitivity analysis of the CALPUFF model for several sources that indicated that tightening of PM emissions by 0.07 lb/MMBtu resulted in negligible

[10] EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.
[11] EPA, 2009. 40 CFR Part 63 [EPA HQ-OAR-2002-058; FRL-RIN 2060-AG69]. National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Pg. 34 – Table 1 – Existing Coal Stoker.

(less than a tenth to several hundredths of a delta dv) visibility improvement. Since a tighter PM emission limit does increase costs and does not result in any appreciable visibility improvement, the Division concludes a PM emission limitation of 0.07 lb/MMBtu is appropriate level of control that satisfies BART.

The Division has determined that an emission limit of 0.07 lb/MMBtu (PM/PM_{10}) represents 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/PM_{10}. The state assumes that the BART emission limit can be achieved through the operation of the existing fabric filter baghouses. Thus, as described in EPA's BART Guidelines, a full five-factor analysis for PM/PM_{10} is not needed for CENC Boilers 4 and 5.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

CENC identified four NO_x control options:

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

Step 2: Eliminate Technically Infeasible Options

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

CENC estimated that the retrofit SCR systems on Boilers 4 and 5 could achieve 0.06 lb/MMBtu. The SCR reaction occurs within the temperature range of 600°F to 750°F where the extremes are highly dependent on the fuel quality. There are three different types of SCR arrangements – high-dust, low-dust, and tail-end. The pre-dominant arrangement applied in the United States has been high-dust. In most circumstances, a high-dust SCR system is the most economical arrangement alternative and would likely be the arrangement for Units 4 and 5 if applicable. For high- and low-dust arrangements, the catalyst, because of its location directly downstream of the boiler and upstream of the air heater, can impact the boiler through its effect on the air heater. The magnitude of this effect is dependent on the power plant configuration, air quality control components, type of fuel, and overall emission control requirements. For retrofit applications, adequate space between the economizer outlet and the air heater inlet to allow boiler outlet and air heater return duct is a prerequisite for the installation of a high-dust system and is the case for the CENC boilers. Therefore, high-dust SCR is a technically feasible alternative for CENC Boilers 4 and 5.

SNCR/SNCR+LNB/SOFA: Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. Reagent utilization, a measure of the efficiency with which the reagent reduces NO_x, can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost. SCNR is considered a technically feasible alternative for CENC Boilers 4 and 5.

LNB/LNB+SOFA: Low NO_x burners are designed to control fuel and air mixing at each burner in order to create large and more branched flames. Peak flame temperature is thereby reduced, and results in less NO_x formation. The improved flame structure also reduces the amount of oxygen available in the hottest part of the flame thus improving burner efficiency. Combustion, reduction and burnout are achieved in three stages within a conventional low NO_x burner. In the initial stage, combustion occurs in a fuel rich, oxygen deficient zone where the NO_x are formed. A reducing atmosphere follows where hydrocarbons are formed which react with the already formed NO_x. In the third stage internal air staging completes the combustion but may result in additional NO_x formation. This however can be minimized by completing the combustion in an air lean environment. Installing LNB with separated OFA may increase carbon monoxide (CO) emissions. LNB/LNB+SOFA are a technically feasible alternative for CENC Boilers 4 and 5.

Low NO_x burners can be combined with other primary measures such as overfire air (OFA) or for even greater NO_x emission reductions, separated overfire air (SOFA). The SOFA system diverts secondary air from the main windbox and injects it into the furnace above the main firing zone. This staged combustion process is one of the first principles of aggressive NO_x reductions. LNB+SOFA is a technically feasible alternative for CENC Boilers 4 and 5.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[12] and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[13] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for CENC Boilers 4 and 5.

[12] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[13] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu[14]. However, this procedure has not been performed on a full-size pulverized coal-fired boiler yet and thus, is considered technically infeasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CENC provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[15] 30-day NO_x rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The Division projected a 30-day rolling average emission rate increased by 15% for CENC Boilers 4 and 5 to determine control efficiencies and annual reductions.

LNB/LNB+SOFA: CENC estimated that low-NO_x burners (Alstom's Low NO_x Concentric Firing System (LNCFS) System) are capable of reducing NO_x 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 NO_x emissions by 19 – 35%, resulting in an annualized estimated 0.32 and 0.28 lb/MMBtu for Boilers 4 and 5 respectively.

EPA's AP-42 emission factor tables estimate low-NO_x burners controlling 35 – 55% and LNB with OFA controlling 40 – 60% of NO_x emissions.[16] A recent AWMA study noted that LNB with close-coupled OFA firing bituminous coal in tangentially fired boilers achieved, on average, 35% NO_x reduction.[17] However, due to the size and configuration (e.g. furnace dimensions) of the CENC boilers, the Division concurs that the estimated control efficiency rates are reasonable.

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 NO_x 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

[14] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf
[15] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.
[16] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[17] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

is consistent with EPA's AP-42 emission factor tables (50 – 80%).[18] 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[19] to conservatively approximate that the CENC boilers can achieve 30% control when SNCR is applied.

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% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.[20,21]
Table 16 summarizes each available technology and technical feasibility for NO_x control.

Table 16: CENC Boilers 4 and 5 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO_x Burners (LNB)	35 – 55%	Y
LNB + OFA	40 – 60%	Y
Overfire air (OFA)	10 – 25% (alone)	Y
Selective non-catalytic reduction (SNCR)	~30 - 50%	Y
SNCR+LNB+SOFA	~50 – 80%	Y
Selective catalytic reduction (SCR)	~75 – 90%	Y
ECO®	n/a	N
RRI	n/a	N
Coal reburn +SNCR	n/a	N

Step 4: Evaluate Impacts and Document Results

[18] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[19] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.
[20] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Table 1.1-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf
[21] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Cost of Compliance

LNB/LNB+SOFA: CENC contracted Alstom Power to determine total installed costs for low-NO_x burners and separated overfire air. Factors from EPA's Cost Control Manual were used to develop the total annual cost estimate. EPA's regulations recommend using the EPA's Office of Air Quality Planning and Standards' Air Pollution Cost Control Manual (Sixth Edition, January 2002) for estimating costs of compliance. This Manual provides guidance and methodologies for developing accurate and consistent estimates of cost for air pollution control devices. The costs that may be estimated include capital costs, operation and maintenance (O&M) expenses, and other annual costs.

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. For example, the annualized costs for LNB for Boilers 4 and 5 are 16.1% and 15.5%, respectively, 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 investments[22]. However, the Division and CENC note that the boilers are much smaller than those examined by the EPA. Therefore, the Division concurs with CENC's cost estimates for LNBs. Further, the Division compared recent NESCAUM studies estimating LNB+SOFA for tangentially-fired boilers as between \$420 - \$1,600 per ton NO_x reduced.[23] Both the original and revised CENC cost effectiveness estimates are within the NESCAUM ranges, providing further verification that cost estimates are reasonable. The NESCAUM study did not provide cost estimate ranges for LNB on tangentially-fired boilers.

SNCR/SNCR+LNB+SOFA: The difficulty of SNCR retrofit on smaller boilers significantly increases, with the primary concern being that there is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required, as in the case of the CENC boilers.

A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.[24] The CENC-estimated SNCR costs for operating expenses are 81% and 86% for Boiler 4 and Boiler 5, respectively. Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x 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_x level, required emission reductions, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty.[25]

---

[22] Environmental Protection Agency, 2009. 40 CFR Part 49: Assessment of Anticipated Visibility Improvements at Surrounding Class I Areas and Cost Effectiveness of Best Available Retrofit Technology for Four Corners Power Plant and Navajo Generating Station: Advance Notice of Proposed Rulemaking. Pg. 44318.
[23] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[24] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.
[25] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

The cost effectiveness for SNCR on Boilers 4 and 5 is about $2,900 and $3,350 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[26,27] EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced.[28] 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.

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.

Recent NESCAUM studies estimate SCR retrofits on tangentially fired boilers achieving NO_x emission rates of 0.10 – 0.15 lb/MMBtu and emission reductions of 75 – 85% as costing $2,600 - $5,000 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[29,30] 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.

Table 17, Table 18, Table 19, and Table 20 depict controlled NO_x emissions and control cost comparisons.

Table 17: CENC Boiler 4 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions				
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)	Annual Average (lb/hour)	30-day Rolling Average (lb/hour)
Baseline	---	599	0.50		179	
LNB	10	539	0.45	0.515	161	185
SNCR	30	420	0.35	0.400	125	144
LNB+SOFA	35	390	0.32	0.372	116	134
SNCR+LNB+SOFA	61	231	0.192	0.221	69	79
SCR	86	84	0.070	0.080	25	29

[26] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[27] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.
[28] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[29] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[30] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.

Table 18: CENC Boiler 5 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions				
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)	Annual Average (lb/hour)	30-day Rolling Average (lb/hour)
Baseline	---	691	0.34		165	
LNB	7	643	0.32	0.368	153	176
LNB+SOFA	18.5	563	0.28	0.322	134	155
SNCR	30	484	0.24	0.277	115	133
SNCR+LNB+SOFA	51	337	0.17	0.193	80	93
SCR	79.6	141	0.07	0.081	34	39

Table 19: CENC Boiler 4 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
LNB	59.9	$193,433	$3,227	$54
SNCR	179.8	$694,046	$3,860	$5
LNB+SOFA	209.8	$678,305	$3,234	-$21
SNCR+LNB+SOFA	368.0	$1,372,351	$3,729	$3
SCR	515.4	$4,201,038	$8,150	$30

Table 20: CENC Boiler 5 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
LNB	48.4	$249,858	$5,166	$107
LNB+SOFA	127.3	$815,829	$6,383	$15
SNCR	207.3	$923,996	$4,458	($24)
SNCR+LNB+SOFA	353.7	$1,739,825.3	$4,918	$3
SCR	550.0	$6,469,610	$11,764	$35

Energy and Non-Air Quality Impacts

LNB/LNB+SOFA: Installing LNB with separated OFA may increase unburned carbon in the ash, commonly referred to as loss on ignition (LOI). Otherwise, there are no known non-air quality impacts associated with low-NO_x burners and separated overfire air systems. Energy impacts are not significant. Thus, this factor does not influence the selection of this control.

SNCR/SNCR+LNB+SOFA/SCR: SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase for the high temperature applications, and potentially somewhat lower for the low temperature alternatives. In addition, any flue gas reheat requirements for the low temperature applications may require significant energy input to heat the flue gas. SCR reagent injection systems have minimal power requirements.

Post-combustion add-on control technologies such as SNCR do increase power needs, in the case of the CENC boilers, 90 kW per hour, or enough energy to power about 9 homes for a year, to operate pretreatment and injection equipment, drive the pumps and fans necessary to supply reagents, overcome additional pressure drops caused by the control equipment, and provide steam in some cases.

SCR systems require additional auxiliary power or power from the existing flue gas fan systems to overcome the pressure loss across the catalyst, to supply dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. For CENC Boilers 4 and 5, the estimated pressure drop across the catalyst is 7 to 8 inches water column and the total energy consumption is approximately 1,000 kW per hour, or enough energy to power about 100 homes for a year.

Installing SNCR or SCR increases levels of ammonia, and may create a ‘blue plume’, if ammonia rates are not adequately controlled. Other environmental factors include ammonia storage and transportation, particularly for anhydrous ammonia. Anhydrous ammonia is clear in the liquid state and boils at a temperature of -28°F. With its low boiling point, liquid anhydrous ammonia must be stored under pressure at ambient temperatures to remain a liquid. With anhydrous ammonia, an invisible vapor or gas is formed as the liquid evaporates during depressurization. Accidental atmospheric release of anhydrous ammonia vapor can be hazardous; therefore, stringent requirements for safety are enforced, and obtaining the permits to allow the storage of large quantities of anhydrous ammonia may prove difficult in densely populated areas. CENC has indicated to the Division that they would prefer to use urea instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a urea reagent versus an ammonia reagent. Refer to “CENC BART Submittals” for more information.

Remaining Useful Life

CENC asserts that there are no near-term limitations on the useful 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.

Step 5: Evaluate Visibility Results

CALPUFF modeling was used to determine the projected visibility improvement associated with various control technologies. The modeling guideline requires that modeled baseline emission rate is the 24-hour peak emission rate. The modeling guideline also requires that, at a minimum, the presumptive emission rate scenario be modeled. Table 21 shows the number of days pre- and post-control. Table 22 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

Per the April 2010 modeling protocol[31], 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_2 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_x emissions at 0.07 lb/MMBtu (SCR control) and SO_2 emissions at 0.258 lb/MMBtu for Boiler 4 and 0.286 lb/MMBtu for Boiler 5.

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.

Table 21: Visibility Results – Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler(s)	NOx Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hr	4	0.67	Rocky Mountain National Park	33	---	---	10	---	---
	5	0.66							
LNB	4	0.45*		n/a					
	5	0.30*		n/a					
SNCR	4	0.35*		n/a					
	5	0.24*		n/a					
LNB+SOFA	4	0.32		33	27	6	10	7	3
NOx Modeled Rate	5	0.28		33	25	8	10	6	4
LNB+SOFA	5	0.24*		n/a					
LNB+SOFA+SNCR	4	0.19		33	27	6	10	7	3
	5	0.17		33	19	14	10	6	4
SCR @ 0.07 lb/MMBtu	4	0.07		33	25	8	10	6	4
SCR @ 0.07 lb/MMBtu	5	0.07		33	19	14	10	6	4

[31] Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

Combo	4 5	0.07 0.07		33	3	30	10	0	10

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "CENC BART Modeling Summary" for more details.

Table 22: Visibility Results – NO_x 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-hr	4 5	0.67 0.66	1.07	---	---	---
LNB	4	0.45*	1.02	0.05	5%	$3,868,660
	5	0.30*	0.89	0.17	16%	$1,435,965
SNCR	4	0.35*	0.99	0.07	7%	$9,507,477
	5	0.24*	0.86	0.21	20%	$4,358,471
LNB+SOFA	4	0.32	0.99	0.08	7%	$8,478,816
NOx Modeled Rate	5	0.28	0.88	0.18	17%	n/a
LNB+SOFA	5	0.24*	0.86	0.21	20%	$3,848,252
LNB+SOFA+SNCR	4	0.19	0.96	0.11	10%	$12,475,919
	5	0.17	0.82	0.25	23%	$7,101,328
SCR @ 0.07 lb/MMBtu	4	0.07	0.89	0.18	17%	$23,734,677
SCR @ 0.07 lb/MMBtu	5	0.07	0.75	0.31	29%	$20,669,680
Combo	4 5	0.07 0.07	0.28	0.79	74%	$18,393,225

* Denotes that output was interpolated by the Division and is not an actual modeled output. See "CENC BART Modeling Summary" for more details.

Step 6: Select BART Control

The Division and CENC worked together to determine a "flexible" BART option for Boilers 4 and 5. CENC initially proposed this option in its' prehearing statement on September 15, 2010. This option incorporates both an individual limit (lb/MMBtu) for each boiler or a combined average (lbs/hr) for both boilers for a 30-day rolling average period. CENC submitted supplemental information regarding a "flexible" BART plan on October 19, 2010 to the Division, citing the preamble to the BART regulations to 'consider allowing sources to 'average' emissions across any set of BART-eligible emission units within a fencline, so long as the emission reductions from each pollutant being controlled for BART would be equal to those reductions that would be obtained by simply controlling each of the BART-eligible source." This determination adheres to the language in the BART preamble.

Based upon its consideration of the five factors summarized herein, the state has determined that NOx BART for Boiler 4 is the following NOx emission rates:

CENC Boiler 4: 0.37 lb/MMBtu (30-day rolling average)
or
0.26 lb/MMBtu Boiler 4 and Boiler 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air. Although the other alternatives achieve better emissions reductions, achieving lower limits through different controls was determined to not be reasonable based on the high cost/effectiveness ratios coupled with the low visibility improvement afforded.

Based upon its consideration of the five factors summarized herein, the state has determined that NO_x BART for Boiler 5 is the following NOx emission rates:

CENC Boiler 5: 0.19 lb/MMBtu (30-day rolling average)
or
0.26 lb/MMBtu Boiler 4 and Boiler 5 combined average (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of low NOx burners with separated over-fire air and selective non-catalytic reduction.

For the emission limits above, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria discussed in section 6.4.3 of the Regional Haze State Implementation Plan.

- Boiler 5: $4,918 per ton NOx removed; 0.26 deciview of improvement

The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Though SCR achieves better emissions reductions, achieving lower limits through SCR was determined to not fall into the guidance cost and visibility improvement criteria discussed in section 6.4.3 of the Regional Haze State Implementation Plan.