Best Available Retrofit Technology (BART) Analysis of Control Options For Colorado Springs Utilities – Drake Plant

I. Source Description

Owner/Operator: Colorado Springs Utilities
Source Type: Electric Utility Steam Generating Unit
SCC (EGU): 10100202
Boiler Type: Three Pulverized Coal, Dry-Bottom, Front-Fired, firing coal and natural gas (Units 5, 6, and 7)

The facility is located at 700 South Conejos Street in Colorado Springs. This facility consists of three (3) steam driven turbine/generator units (Units 5, 6, and 7) and the associated equipment needed for generating electricity. These units fire coal as the primary fuel and use natural gas for backup and startup. The facility also includes the various processes necessary to handle the coal and ash. The coal and flyash handling systems are provided with baghouses for air pollution emission control of PM and PM_{10} at appropriate point sources. In addition, the coal is treated with chemical additives to reduce fugitive emissions. Table 1 depicts technical information for each boiler at the Drake Plant.

Table 1: Drake Boilers Technical Information

	Unit 5	Unit 6	Unit 7
Placed in Service	October 28, 1962	July 27, 1968	June 14,1974
Boiler Rating, MMBtu/Hr for coal	548	861	1,336
Electrical Power Rating, Gross Megawatts	51	85	142
Description	Riley Pulverized Coal Front Fired Dry Bottom, firing natural gas and coal. 548 MMBtu/Hr w/ coal, 514 MMBtu/Hr w/ NG.	Babcock and Wilcox Pulverized Coal Front Fired Dry Bottom, firing natural gas and coal. 861 MMBtu/Hr w/ coal 850 MMBtu/Hr w/ NG.	Babcock and Wilcox Pulverized Coal Front Fired Dry Bottom, firing natural gas and coal. 1336 MMBtu/Hr w/Coal, 1310 MMBtu/Hr w/ NG.
Air Pollution Control Equipment	Reverse-Air Fabric Filter Baghouse- installed in May 1998	Reverse-Air Fabric Filter Baghouse – installed in September 1978	Reverse-Air Fabric Filter Baghouse– installed in November 1993
Inherent Special Features	Low NO_x burners – placed in service in May 1998	Low NO_x burners – placed in service in March 1998	Low NO_x burners – placed in service in October 1999
Monitoring Equipment	COM CEMs for SO_2 , NOx,	COM CEMs for SO_2 , NOx,	COM CEMs for SO_2 , NOx,

	CO_2, and stack gas flow rate	CO_2, and stack gas flow rate	CO_2, and stack gas flow rate
Emissions Reduction (%)*	NO_x – 54.7% SO_2 – None PM – 99.7% PM_{10} – 98.6%	NO_x – 52.8% SO_2 – None PM – 99.6% PM_{10} – 98.2%	NO_x – 57.7% SO_2 – None PM – 99.8% PM_{10} – 99.1%

*Emissions Reduction estimated by comparing uncontrolled AP-42 factor to actual average emission factor for PM/PM_{10}. For NO_x estimates, CAMD data was used to calculate reduction. See "Drake APCD Technical Analysis" for further details. Not based on actual testing.

Boilers 5, 6, and 7 are considered BART-eligible, being fossil-fuel steam electric plants of more than 250 MMBtu/hr heat input 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. The combined emissions of these boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, all three boilers are subject-to-BART. Initial air dispersion modeling performed by the Division demonstrated that the Martin Drake Plant contributes to visibility impairment (a 98th percentile impact equal to or greater than 0.5 deciviews) and is therefore subject to BART. Colorado Springs Utilities (CSU) submitted a BART Analysis to the Division on August 1, 2006 with updated cost information submitted on March 29, 2007. CSU also provided information in "NOx and SO2 Reduction Cost and Technology Updates for Colorado Springs Utilities Drake and Nixon Plants" Submittal provided on February 20, 2009 as well as additional information upon the Division's request on February 21, 2010, March 21, 2010, May 10, 2010, May 28, 2010, June 2, 2010, and June 15, 2010. These documents are all provided as "CSU Drake BART Submittals".

Regulations that apply to these boilers are as follows:

- State Regulation No. 1, III.A.1.c limits particulate matter emissions to 0.1 lb/MMBtu.
- State Regulation No. 1, VI.A.3.a.(ii) limits sulfur dioxide emissions to 1.2 lb/MMBtu.
- 40 CFR, Part 76-Acid Rain Nitrogen Oxides Emission Reduction Program limits NO_X emissions to 0.46 lb/MMBtu of heat input on an annual average basis.
- No other annual emission limitations or State Regulations since units are Grandfathered[1].

II. Emissions for Units 5, 6, & 7

CSU estimated that a realistic depiction of anticipated annual emissions for Boilers 5, 6, and 7, or "Baseline Emissions", to be conservative, was the average of two previous years (2004, 2005) of emissions data in the August 1, 2006 analysis. Several years have

[1] Colorado Department of Public Health and Environment Air Quality Control Commission Regulation Number 3 Stationary Source Permitting and Air Pollutant Emission Notice Requirements 5 CCR 1001-5 Part G.IV states: "A source existing before the adoption of the first Colorado Air Quality Control Act and the date of its implementing regulations of February 1, 1972, is not required to obtain a permit. This revision is intended to clarify the date prior to which existing sources are considered "grandfathered" and exempt from permit requirements."

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 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: CSU Boilers 5, 6 and 7 Baseline Emissions

Pollutant	Boiler 5		Boiler 6		Boiler 7	
	Annual Emissions* (tpy)	Annual Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Annual Emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Annual Emissions** (lb/MMBtu)
NO_x	768	0.38	1,413	0.42	2,081	0.39
SO_2	1,269	0.63	2,785	0.82	4,429	0.83
PM_{10}	27	0.01***	58	0.02***	55	0.01***

*Using daily CEMs data from 2006 – 2008 calendar years (CAMD data).
**The Division calculated average emission rate (lb/MMBtu) from the 2006 - 2008 calendar years (CAMD data) based on average daily reported data for each unit for NO_x and SO_2 emissions.
***The PM_{10} emission rate is determined from the Title V permit compliance stack test. These values are as follows: Drake #5 – 0.0132 lb/MMBtu; Drake #6 – 0.0186 lb/MMBtu; Drake #7 – 0.0111 lb/MMBtu.

III. Units Evaluated for Control

As documented by CSU, these boilers fire a variety of coal types, including coal from the southern Powder River Basin (PRB, located in Wyoming), ColoWyo coal (from northwestern Colorado), 20-Mile Foidel Creek coal (northwestern Colorado), and West Elk coal (western Colorado). The specifications for these coals are listed below in Table 3 (averaged from 2006 – 2008). Table 4 lists the 2006 – 2008 averaged APEN-reported coal characteristics for each boiler. Table 4 is not based on percent of various coals fired, but instead based on the Division's Air Pollutant Emission Notice (APEN) database. Sources submit annual emissions data using APENs. Due to equipment limitations, these boilers cannot achieve full load on PRB-sourced coal and instead fire a blend of the above listed coals. The ratio of PRB was discussed in the initial BART analysis submitted by CSU in an effort to demonstrate that firing sub-bituminous coal may have a minimal effect (if any) on a boiler's NOx emissions. In fact the data suggested at that time that 100% sub-bituminous coal had no effect on NOx emissions for some of the boilers. CSU notes that this effect may be boiler specific. The difference in sulfur content and resultant SO_2 emissions was not discussed in the initial BART analysis. Colorado's BART guidance (Regulation No. 3, Part F, Section IV.B.1.f) states that sources may include an evaluation of representative characteristics of coals from sources they reasonably expect to use, so that these characteristics may be considered in a particular BART limit.

Table 3: Drake Plant Coal Specifications (2004 – 2005)

Coal Mine/Region	Southern PRB	Colowyo	20-Mile Foidel Creek	West Elk
Coal Rank Classification	Sub-bituminous	Sub-bituminous, Class A	Bituminous	Bituminous

As Received Analysis				
H_2O (Moisture %)	27.11	17.42	9.62	7.55
Ash (%)	4.64	5.71	11.93	8.71
Sulfur (%)	0.21	0.37	0.52	0.45
Nitrogen (%)	0.69	1.35	1.57	1.30
Heating Value (HHV Btu/lb)	8,805	10,392	11,084	12,266

Table 4: Coal Specifications (2006 – 2008 Averaged APEN data)

	Specifications		
Emission Unit	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Boiler #5	9,798	0.36	8.14
Boiler #6	10,749	0.47	10.38
Boiler #7	11,117	0.50	11.14

Table 1 lists the units at Colorado Springs Utilities Drake Plant that the Division examined for control to meet BART-eligible requirements. Controlled and uncontrolled emission factors and CAMD data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 5. The factors are based on firing bituminous coal for conservative estimates.

Table 5: Uncontrolled emission factors for CSU Drake BART-eligible sources[2]

	Pollutant (lb/ton)*			
Emission Unit	NO_x	SO_2	PM (filterable)	PM_{10} (filterable)
Boiler #5	22	13.6	81.5	18.7
Boiler #6	22	18.0	103.8	23.9
Boiler #7	22	18.8	111.4	25.6

*SO_2 and PM/PM_{10} factors are determined by the applicable AP-42 equation, where %S and %A are the % of sulfur and ash present in the coal supply, respectively, determined from Table 4.

A. Sulfur Dioxide (SO_2)

Step 1: Identify All Available Technologies

CSU identified one control option for Units 6 and 7:
Semi-dry flue gas desulfurization (dry FGD) aka lime spray drying (LSD/SDA)
CSU identified two control options for Unit 5:
Semi-dry flue gas desulfurization (dry FGD) aka lime spray drying (LSD/SDA)
Dry sorbent injection – Trona (DSI)

The Division also identified and examined additional control options for these units:
Lime/limestone-based wet FGD – all units
Emission limit tightening – Unit 5 (no control)

Step 2: Eliminate Technically Infeasible Options

[2] EPA AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1, Tables 1.1-3 and 1.1-4. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

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 that uses 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 results 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[3]. 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[4] 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 West Cimarron Street, to the west by federal Interstate Highway 25 and Fountain Creek, to the east by Conejos Street, and the south by Fountain Creek (as the Interstate and the Creek curve to the southeast). Train tracks (the Drake rail spur) also bound the facility to the north, south, and west. Along the east side of the plan (immediately east of Conejos Street) is the main railroad line. 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 Drake Plant, due to locations as well as pollution control retrofits for particulate matter. As figure 2 indicates, the square footage available to accommodate a FGD for Unit 5 is 3,025 ft^2 and Units 6 & 7 is 8,346 ft^2 (or about 4,000 ft^2 per unit). The entire site is very congested, with limited access and limited room for major retrofits of new capital equipment. Demolition and site reconfiguration would be required for FGD systems on these units and has been included in the cost analysis provided by Drake. CSU determined that it is technically feasible to install a dry FGD on Unit 5, Unit 6 and Unit 7.

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[3] 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.

[4] 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.

Figure 1: Drake Plant Physical Boundaries

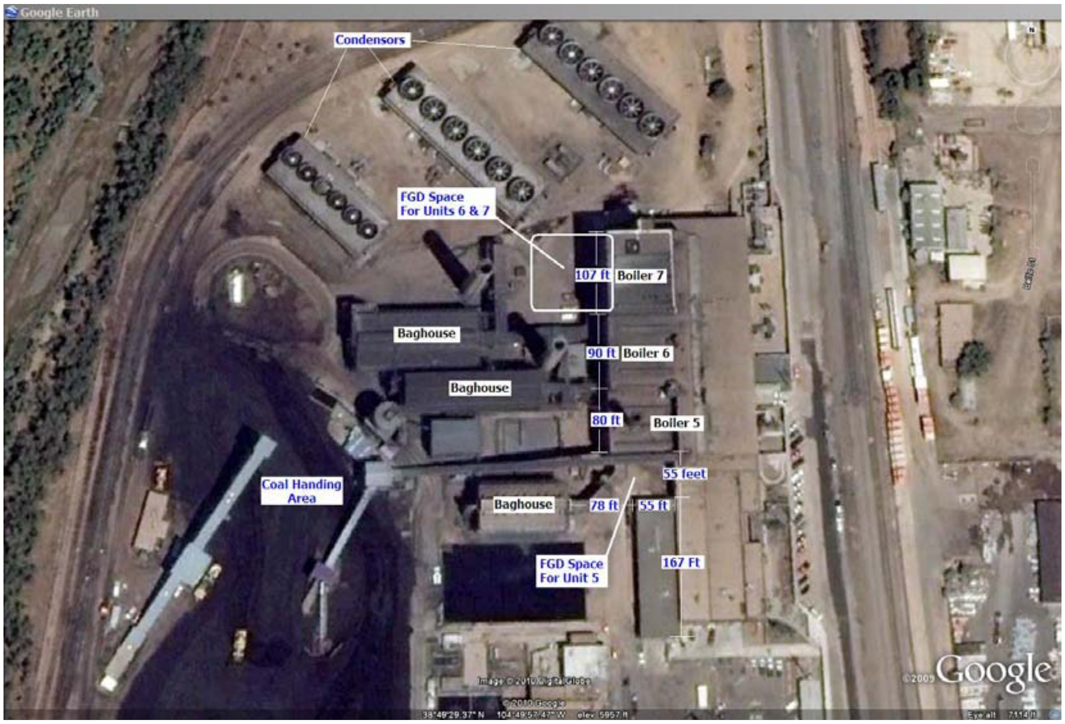

Figure 2: Drake Plant Detailed View

The Division conducted site visits and determined:

- Unit 5
  - CSU determined dry FGD controls are technically feasible although available physical space was severely constrained and some demolition and site reconfiguration would be required; the Division conducted a site visit and determined that dry FGD controls were not appropriate considering the space constraints, shown in Figure 1 and Figure 2. Therefore control effectiveness and impacts for dry FGD are not evaluated in this analysis.
  - Traditional wet FGD controls are possible considering that there is adequate space near the baghouse to allow for the installation of controls, but is being 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 Unit 5.
- Units 6 and 7
  - Dry FGD controls are technically feasible for Units 6 and 7.
  - Traditional wet FGD controls are possible considering that there is adequate space near the baghouse to allow for the installation of controls, but is being 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 Units 6 and 7.

It is worth noting that CSU-Drake is currently testing a new, innovative non-traditional wet scrubber control system that appears to be as effective, if not more effective, at controlling SO_2 emissions with much less pressure drop (less parasitic load from increased fan demands) and requires a much smaller operational foot print area in comparison to traditional wet scrubbing.. The pilot-scale wet scrubber control system, called the NeuStream-S FGD process, is presently being tested on a 20 MW flue gas stream. CSU anticipates scaling the non-traditional wet scrubber control to full scale pending successful outcome of the current testing. This new wet scrubber technology uses a unique contacting vessel that makes it different from traditional wet scrubbers. It affords a higher liquid to gas contact ratio and so uses much less water / has lower pressure drop. It also uses a dual alkali system that is somewhat unique when compared to most traditional wet scrubbers. In comparison to traditional wet and LSD scrubbers, this new technology will have smaller water and energy requirements. There are several non-air quality aspects of the NeuStream-S process that compare favorably to traditional scrubbers, described in Step 4. Regarding the applicability of the NeuStream process to Drake Unit 5, the Division notes that this technology is not commercially available at this time. CSU has not determined if this technology is feasible for this smaller unit. However, the Division will re-assess this technology in the next Regional Haze planning period.

Although the technology being tested by CSU does not technically meet the definition of "available" as set forth in the BART rules, the Division is willing to allow CSU the opportunity to prove the technology and if successful, the opportunity to install the NeuStream-S FGD scrubber. This process will be required to meet the emission limits established for the LSD technology established in this BART determination. Regardless of the technology utilized, Drake has to meet the LSD-based BART limits within 5 years of EPA approval of the BART

SIP. CSU will test the NeuStream system until December 2011, and at that time, determine the control technology that will be used to comply with the specified SO_2 BART limits for Units 6 and 7.

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 as in the case of the Drake boilers. CSU asserts that the flue gas temperatures present downstream of the Unit 5 airheater 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. CSU's preliminary review indicates that even with the added loading of DSI reagent, the Drake baghouses would be operating within the design specification for particulate loading. 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.

One major challenge of DSI systems is the possibility of converting the NO_x present in the flue gas from NO which is colorless to NO_2 which has a reddish-brown color. This conversion of NO to NO_2 can create a brown plume from the stack which could create opacity compliance issues. 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, CSU estimated the maximum SO_2 removal rate that can be achieved while minimizing the creation of the brown plume condition to be 60% 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. Therefore, DSI is technically feasible for Drake Plant Unit 5. The Division assumes that this same technology is also then technically feasible for Unit 6 and Unit 7.

Emission limit tightening (unit 5 only): The Division conducted technical analyses 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 all units. However, the Division only examined this option for Unit 5 since when this option was examined; preliminary SO_2 determinations had already been established for all units. Unit 5 was the only unit where the emission limit could potentially be achieved with the assumption of no control.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

CSU 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 Units 5, 6, and 7 to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by CSU 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.

Dry FGD (LSD): Controlling SO_2 Emissions: A Review of Technologies[5] indicates that the median control efficiency for dry FGD processes, such as LSD, is 90%. Typically dry FGD technology is applied to units that fire coal with a sulfur content below 1.0% to 1.5%. However, when concentrations of pollutants are low, as is the case with low-sulfur western coal, the achievable control efficiency will drop. Due to the very low sulfur content of the coal burned at the Drake Power Plant, typically <0.5% as detailed in Table 3, a 90% removal rate is at the upper end of what may reasonably be expected in practice. Additionally, achievement of a 90% removal rate on a long-term basis would require levels of equipment redundancy that may not be feasible to locate at a congested site such as the Drake Power Plant.
DSI: Based on literature review, CSU estimated the maximum SO_2 removal rate that can be achieved to be 60% SO_2 removal. The Division concurs that this control efficiency is reasonable for retrofit on these units.

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 for Unit 5 was 0.83 lb/MMBtu. As explained above, the Division projects 30-day rolling SO_2 emission rates to be approximately 5% higher than annual average emission rates. The uncertainty of evaluating a "maximum" emission rate warrants a similar 5% buffer to be applied in this case, especially due to the fact that the Drake facility has limited coal storage capacity and blends four different types of coals. Therefore, an appropriate SO_2 emission limit assuming no control technology for Unit 5 is 0.9 lb/MMBtu on a 30-day rolling average.

Table 6 summarizes each available technology and technical feasibility for SO_2 control.

[5] 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.

Table 6: Drake Units 5, 6, and 7 SO_2 Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Wet FGD	95%	Y
Dry FGD (LSD)	81 – 90%	N – Unit 5 Y – Units 6 & 7
DSI	60% (CSU)	Y

Step 4: Evaluate Impacts and Document Results

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.

LSD/DSI: CSU submitted cost estimates for LSD systems on Units 5, 6 and 7 in the original BART submittal on August 1, 2006 and updated refined cost estimates on March 29, 2007. CSU provided cost estimates for the DSI system evaluated on Unit 5 on May 10, 2010.

The application of LSD or DSI would remove nearly all of the halogens in the flue gas, thus improving the acid gas removal of the baghouse. However, it is anticipated that LSD or DSI would also lower the inherent mercury removal in the baghouses. Recent mercury tests at the Drake Plant have shown that the amount of mercury leaving the stack is approximately 60 – 90% less than what would have been expected based on coal analysis. It is believed that the halogens present in the flue gas are oxidizing the mercury, which is subsequently removed in the baghouse. The application of LSD or DSI would remove the halogens in the flue gas, which may lead to reduced mercury control. Due to this possibility, the provision of adding mercury control via activated carbon injection as part of a LSD or DSI system has been included in the estimated cost of LSD/DSI application.

The Division compared CSU's updated cost information to the study that EPA conducted in developing presumptive BART limits,[6] shown in Table 7.

Table 7: CSU-Drake SO_2 LSD Control Cost Comparison

Unit Capacity (MW)	EPA's Calculated Cost Effectiveness for MW Group (\$/ton SO_2 Removed)	CSU Refined Cost Estimate (\$/ton SO_2 Removed (Control System))	Cost Differential
Unit 6 –	\$2,399	\$2,579 - \$2,981	+ 8% – 24%

[6] EPA, 2005. Technical Support Document for the Best Available Retrofit Technology (BART) Notice of Final Rulemaking: Setting BART SO_2 Limits for Electric Generating Units: Control Technology and Cost-Effectiveness.

85 MW			
Unit 7 – 142 MW	$1,796	$2,140 - $2,694	+ 19% - 50%

EPA's study was published in 2005 whereas CSU sent the Division updated cost analyses for LSD systems on Units 6 and 7 using various cost updates from the 2006 timeframe. Drake has reflected the costs of retrofitting a facility that is already congested with limited room and access for major retrofits of new capital equipment in the retrofit multiplier that is applied to the cost of new equipment. Therefore, the Division considers CSU's updated cost information for the LSD controls on these units to be reasonable estimations for the cost of control.

The Division considers this cost to be within a reasonable cost range that is comparable to other Colorado facility submittals.[7] Therefore, the Division did not adjust CSU's cost estimates. CSU only submitted DSI cost information for Unit 5. The Division scaled this cost information for Units 6 and 7 in Table 9, Table 10, and Table 11. Please see "Drake APCD Technical Analysis" for more details.

For dry FGD, CSU estimated a removal rate of 83.3% based on a worst-case coal sulfur concentration of 0.9 lb/MMBtu, baseline years 2004 and 2005, and a resulting emission rate at the BART presumptive limits of 0.15 lb/MMBtu. The Division adjusted this removal rate using the baseline SO_2 emissions from Table 2 (lb/MMBtu and tons/year) for each unit and using a realistic removal rate of 76 – 90%that meets or exceeds BART presumptive limits for Units 6 and 7, and exceeds the limits for Unit 5. This range allows the Division to determine the most reasonable BART limit for this control option, if applicable. The Division scaled costs linearly for the LSD systems for higher control efficiencies as applicable. See "Division APCD Technical Analysis" for more details.

Emission limit tightening: There are no costs associated with this option for unit 5. This option is considered equivalent to the "baseline" row in the tables below, and is not considered as a separate cost option.

Table 8 illustrates resultant SO_2 emissions for each technically feasible control option. Table 9, Table 10, and Table 11 show the SO_2 control cost comparisons for each unit based on the detailed cost analyses. The Division used baseline emissions from Table 2. The Division analyzed both annual and 30-day rolling average limits. The Department's experience with power plants suggests that the maximum 30-day rolling average SO_2 emission rate is approximately 5% higher than the annual average emission rate.

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

Table 8: Units 5, 6, and 7 Control Resultant SO_2 Emissions

Alternative	Control Efficiency (%)	Resultant Emissions								
		Unit 5			Unit 6			Unit 7		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day rolling Average (lb/MMBtu)	Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day rolling Average (lb/MMBtu)	Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day rolling Average (lb/MMBtu)
Baseline	---	1,269	0.63		2,785	0.82		4,429	0.83	
DSI	60	508	0.25	0.26	1,114	0.33	0.34	1,771	0.33	0.35
Dry FGD (LSD)	82				501	0.15	0.15	797	0.15	0.16
Dry FGD (LSD)	85				418	0.12	0.13	664	0.12	0.13
Dry FGD (LSD)	90				279	0.08	0.09	433	0.08	0.09

Table 9: Drake Unit 5 SO_2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
DSI	762	$1,340,663	$1,760	$1,760

Table 10: Drake Unit 6 SO_2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
DSI	1,671	$2,234,438	$1,337	$1,337
Dry FGD (LSD) @ 82% control	2,284	$6,186,854	$2,709	$6,540
Dry FGD (LSD) @ 85% control	2,368	$6,647,835	$2,808	$5,517
Dry FGD (LSD) @ 90% control	2,507	$7,452,788	$2,973	$5,780

Table 11: Drake Unit 7 SO_2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
DSI	2,657	$3,732,826	$1,405	$1,405
Dry FGD (LSD) @ 82% control	3,632	$8,216,863	$2,263	$4,602
Dry FGD (LSD) @ 85% control	3,764	$8,829,321	$2,345	$4,610
Dry FGD (LSD) @ 90% control	3,986	$9,898,382	$2,483	$4,828

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.[8]

There are other environmental impacts that the Division also considers undesirable with respect to wet scrubbers. Potential 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 river valley will produce a noticeable cloud that will hang over a densely populated area (City of Colorado Springs). 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.

Semi-dry FGD (LSD): CSU notes that there are a number of non-air quality environmental impacts with regard to lime spray dryer systems. Application of a dry scrubber will tend to remove halogens from the flue gas (primarily chlorine) that are important to the removal of mercury from the flue gas. Several sources of speciated mercury stack test data, including EPA's own ICR stack test data, show that an unscrubbed plant with a baghouse burning western coal will remove more mercury from the flue gas when compared to a similar plant with a scrubber.

[8] 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.

There will be a greater volume of material being landfilled. A LSD scrubber consumes a significant amount of water, as detailed in Table 12.

Table 12: LSD Water Requirements

Unit	Water required for LSD (gpm)	Water required for LSD (Mg/year)
6	68	35.7
7	100	53.0

CSU states that the direct energy cost of the LSD systems due to additional auxiliary loads on the plant, as well as increased headloss through the scrubber, is the primary energy impact. These loads reduce the net output of each unit; therefore, both the lost energy production, as well as the reduced capacity, must be replaced. CSU estimates energy costs for replacement capacity and differential cost between existing MW-h of output and a replacement MW-h in **Error! Reference source not found.**. This is the incremental cost of a unit of replacement energy, and does not double count the direct energy cost already included in the operating cost. The reduced unit output will consequently reduce unit efficiency, thereby increasing emissions of CO_2 when measured on a per MW-h basis.

Table 13: LSD Energy Replacement Costs

Unit	Replacement capacity cost ($/kW-yr)	Differential energy cost ($/MW-h)
6/7	44	35

This information, including detailed capital and annual cost data, are provided as "CSU Drake BART Submittals". CSU originally generated costs using EPRI's FGD Cost model.[9] This model uses specific unit data to calculate the cost of controlling emissions, and is considered to be accurate within ± 30%. The refined cost estimates from March 2007 were further extrapolated to account for retrofit difficulties, annual inflation, and also hyperinflation of certain construction commodities and energy. The March 2007 submittal also incorporates budgetary quotes from vendors for the major pieces of equipment as well as noting the need for a non-recycling LSD due to the ash removal system's operation at a very high capacity factor. As depicted in Figure 3, a non-recycling LSD would eliminate slurry solids; instead the FGD solids (removed in the baghouse) are immediately disposed.

[9] EPA's BART Guidelines recommend that the OAQPS Control Cost Manual be used to develop cost estimates, where possible. Unfortunately, the Control Cost Manual does not contain a section for SO2 removal equipment as of the date of this report. The Fifth edition (EPA 453/B-96-001) of the Control Cost Manual is referenced in the BART guideline; however, the Sixth edition (EPA 452/B-02-001, 7-22-2002) is now available.

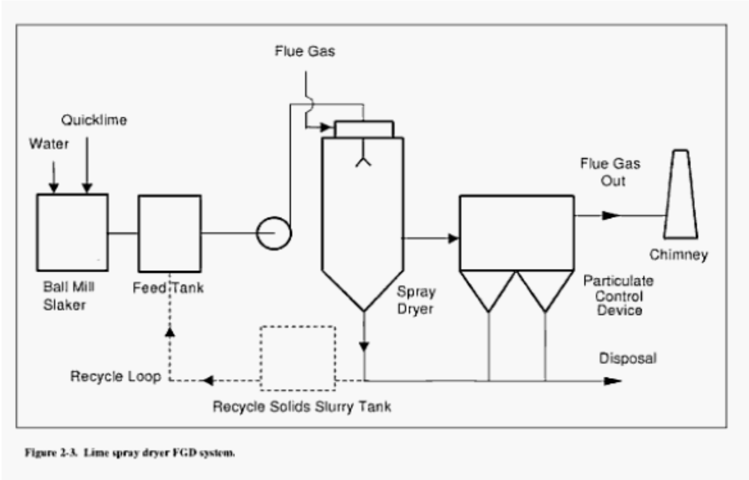

Figure 3: Lime Spray Dryer (LSD) Schematic[10]

Although these non-air quality/energy impacts have been identified, the State has determined that these impacts are not significant or unusual enough to warrant elimination of this control option.

DSI: CSU 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. Application of DSI would be effective in further enhancing the removal of halogenated acid gases in the baghouse. 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 at some plants,[11] 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.

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.

[10] EPA, 2000. "Controlling SO_2 Emissions: A Review of Technologies." Prepared by Ravi K. Srivastava for Office of Research and Development, Washington, D.C. 20460. Pg. 12.
[11] 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

Remaining Useful Life
CSU asserts that the remaining useful life of Drake Units 5, 6, and 7 are each in excess of 20 years, which is the maximum amortization period allowed in the BART analysis. 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 14 shows the number of days pre- and post-control. Table 15 depicts the visibility results (98^{th} 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[12], 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 (NO_x and PM/PM_{10}) 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 all units with NO_x emissions at 0.07 lb/MMBtu and SO_2 emissions at 0.12 lb/MMBtu for Units 6 and 7 and at 0.32 lb/MMBtu for Unit 5. The Division modeled Drake Unit 5 for 0.12 lb/MMBtu as a theoretical examination of the potential impacts of lower emission limits on that unit.

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

SO_2 BART Control Limit	Unit(s)	SO2 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 SO_2 rates	5	0.943	Rocky Mountain National Park	34	---	---	17	---	---
	6	0.997							
	7	0.994							
DSI	5	0.251		34	32	2	17	14	3

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

	6	0.328		34	32	2	17	14	3
	7	0.333		34	31	3	17	13	4
dry FGD (LSD)	5	0.120		n/a					
	6	0.120		34	31	3	17	14	3
	7	0.120		34	28	6	17	12	5
dry FGD (LSD)	6	0.100		34	31	3	17	14	3
	7	0.100		34	28	6	17	12	5
dry FGD (LSD)	6	0.070		34	31	3	17	14	3
	7	0.070		34	28	6	17	12	5
Combo	5	0.321		34	1	33	17	0	17
	6	0.120							
	7	0.120							

Table 15: Visibility Results – SO_2 Control Options

SO2 Control Scenario	Boiler(s)	SO2 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 SO_2 rates	5	0.943	1.84	---	---	---
	6	0.997				
	7	0.994				
DSI	5	0.251	1.72	0.12	6%	$14,673,714
	6	0.328	1.65	0.18	10%	$15,903,206
	7	0.333	1.55	0.29	16%	$16,765,140
dry FGD (LSD)	5	0.120	n/a			
	6	0.120	1.59	0.24	13%	$27,470,391
	7	0.120	1.45	0.39	21%	$22,697,484
dry FGD (LSD)	6	0.100	1.59	0.25	14%	n/a
	7	0.100	1.44	0.40	22%	n/a
dry FGD (LSD)	6	0.070	1.58	0.26	14%	$28,999,176
	7	0.070	1.42	0.41	22%	$23,967,026
Combo	5	0.321	0.25	1.59	86%	n/a
	6	0.120				
	7	0.120				

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that SO_2 BART for Unit 5 is the following SO_2 emission rate:

Drake Unit 5: 0.26 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limit can be achieved through the installation and operation of dry sorbent injection. Other alternatives are not feasible.

Based upon its consideration of the five factors summarized herein, the state has determined that SO_2 BART for Unit 6 and Unit 7 is the following SO_2 emission rates:

Drake Unit 6: 0.13 lb/MMBtu (30-day rolling average)
Drake Unit 7: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of lime spray dryers (LSDs). A lower emissions rate for Units 6 and 7 was deemed to not be reasonable as increased control costs to achieve such an emissions rate do not provide appreciable improvements in visibility (0.02 delta deciview for both units respectively).

The emission rates for Units 6 and 7 provide 85% SO_2 emission reduction at a modest cost per ton of emissions removed and result in a meaningful contribution to visibility improvement.

- Unit 6: $2,808 per ton SO_2 removed; 0.24 deciview of improvement
- Unit 7: $2,345 per ton SO_2 removed; 0.39 deciview of improvement

B. Filterable Particulate Matter (PM_{10})

Drake Units 5, 6, and 7 are each equipped with reverse-air 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 95OPEP107 Condition 2.4.2 requires Units 5, 6, and 7 to conduct performance testing for PM_{10} annually. While the emission in Condition 2.4 is set at 0.1 lb/MMBtu, the annual performance test must be used as an emission factor in determining emissions.

Table 16 shows the most recent stack test data (June 14, 2006). It is important to note that the most recent stack test, which at a minimum, occurs every five years, and more frequently depending on the results, demonstrates that these baghouses are meeting >95% control.

Table 16: Drake 2006 Stack Test Results

Pollutant	Unit 5 (lb/MMBtu)	Unit 6 (lb/MMBtu)	Unit 7 (lb/MMBtu)
Filterable PM_{10}	0.0132	0.0186	0.0111

PM_{10} Control efficiency	98.6%	98.3%	99.0%

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 (i.e. wet and dry FGD systems). 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.

The State determines that the existing regulatory emissions limit of 0.03 lb/MMBtu (PM/PM_{10}) for the three units represents the most stringent control options. 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 Drake Units 5, 6, and 7.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

CSU identified four NO_x control options:

- Overfire air (OFA)
- Ultra-low NO_x burners (ULNBs)
- Selective Catalytic Reduction (SCR)
- Ultra-low NO_x burners and SCR (ULNBs + SCR)

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

- Electro-Catalytic Oxidation (ECO)®
- Rich Reagent Injection (RRI)
- Selective Non-Catalytic Reduction (SNCR)
- Ultra-low NO_x burners and Over-fire air (ULNB+OFA)
- Coal reburn +SNCR

Rotating overfire air (ROFA) was not considered in this analysis because ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load[13]. While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+OFA and cannot achieve the predicted 70% or greater NO_x reduction for Units 5, 6, and 7. Since ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for this unit, ROFA® technology is not considered further in this analysis.

Step 2: Eliminate Technically Infeasible Options

[13] Nalco-Mobotec, ROFA Technology, 1992-2009, http://www.nalcomobotec.com/technology/rofa-technology.html

OFA: Air staging or two-stage combustion, is generally described as the introduction of overfire air into the boiler or furnace. Staging the air in the burner (internal air staging) is generally one of the design features of low NO_x burners, such as those already present on Units 5, 6, and 7. Furnace overfire air (OFA) technology requires the introduction of combustion air to be separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of N_2 rather than NO_x. Primary air (70-90%) is mixed with the fuel producing a relatively low temperature; oxygen deficient, fuel-rich zone and therefore moderate amounts of fuel NO_x are formed[14]. The secondary (10-30%) of the combustion air is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles, mounted above the burners. Combustion is completed at this increased flame volume. Hence, the relatively low-temperature secondary-stage limits the production of thermal NO_x. The location of the injection ports and mixing of overfire air are critical to maintain efficient combustion. Retrofitting overfire air on an existing boiler involves waterwall tube modifications to create the ports for the secondary air nozzles and the addition of ducts, dampers and the wind-box. OFA is a technically feasible option for Units 5, 6, and 7.

ULNBs: Each unit has low NO_x burners installed, shown in Table 1 . These LNBs can be replaced with ULNBs. Burner designs have improved in recent years to improve flame stability and combustion control schemes for increased NO_x emission reductions with these ultra-low NO_x burners. ULNBs are a technically feasible option for Units 5, 6, and 7.

ULNB+OFA: Since ULNB and OFA are each technically feasible options and would be installed separately for Units 5, 6, and 7, it stands to reason that ULNB+OFA is technically feasible option for Units 5, 6, and 7.

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, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. 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.

While lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for CSU, a retrofit SCR, the 0.07 lb/MMBtu controlled NO_x value is more expected. 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 Unit 5, 6, and 7 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

[14] IEA Clean Coal Centre: Clean Coal Technologies – Air Stating for NO_x control (overfire air and two-stage combustion), 2010. http://www.iea-coal.org/site/ieacoal_old/clean-coal-technologies-pages/air-staging-for-nox-control-overfire-air-ofa-or-two-stage-combustion?

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 at the Drake Plant. Therefore, high-dust SCR is a technically feasible alternative for Drake Units 5, 6, and 7.

ULNBs/SCR layered: A layered approach of installing ULNBs pre-combustion and SCR post-combustion is technically feasible for Drake Units 5, 6, and 7. This scenario considers that less NO_x would enter the SCR system and reduce aqueous ammonia storage, handling, and injection. CSU considered this scenario to determine if this option would be more economically and technically feasible for the three boilers at the Drake Plant.

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[15] 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[16] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 5, 6, and 7.

SNCR: 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.

It should be noted that selective non-catalytic reduction (SNCR) was not considered in CSU's BART analysis because CSU asserts that SNCR achieves full-load NO_x removal in the same range as ULNB at a higher levelized cost (\$/ton NO_x removed), and therefore should be ruled out due to a "least-cost envelope" analysis as detailed in the BART rule. The higher cost is primarily due to much higher operating costs, with most of the operating costs being for the reagent. Additionally, the chemical reaction required for SNCR to work is temperature sensitive. The CSU Drake boilers often operate below full load, when the temperature is no longer conducive to optimal NO_x removal, resulting in NO_x removal declines. The weighted average NO_x removal over an annual load range can be less than ULNB depending on the portion of time the units operate at partial load. Therefore, SNCR was eliminated from consideration by CSU because of higher costs and efficiency losses at partial loads. However, the Division considers SNCR a

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

technically feasible alternative for Drake Units 5, 6, and 7. Similar Colorado facilities evaluated SNCR as an option and it is recognized nationally as a NO_x control option for EGUs, so the Division included SNCR in the full four-factor analysis.

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[17]. 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

CSU provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[18] 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 Drake Units 5, 6, and 7 to determine control efficiencies and annual reductions.

OFA: CSU estimated that overfire air, in conjunction with the existing low-NO_x burners, is capable of reducing NO_x emissions approximately an additional 20% from existing conditions in the original BART submittal (August 1, 2006). 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.[19] The low NO_x burners currently achieve about 50 – 56% control. However, in a more recent AWMA study, it is noted that OFA achieves an additional 10 – 25% control with the installed low NO_x burners.[20] Therefore, the Division concurs with CSU's additional 20% NO_x control estimate.

ULNBs: CSU asserts that additional NO_x reductions of 20 – 30% are possible with implementation of some or all of the modifications that will be needed to retrofit ULNBs at the Drake boilers. These additional NO_x reductions could be achieved while meeting acceptable CO levels. The ULNBs are estimated to control approximately 75% of uncontrolled NO_x emissions, which is consistent with a U.S. Department of Energy Study which estimated NO_x emissions reductions between 75 – 85%.[21] Therefore, the Division concurs with CSU NO_x reduction estimat3es for ULNBs.

[17] 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
[18] State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.
[19] 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
[20] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.
[21] U.S. Department of Energy, 2004. Office of Fossil Energy, National Energy Technology Laboratory. http://www.netl.doe.gov/publications/factsheets/project/Proj294.pdf

ULNB+OFA: The Division used information from CSU regarding ULNBs and OFA control efficiencies as described above. CSU noted in the February 2009 submittal that ULNB are assumed to achieve 20% efficiency *assuming* OFA is already installed (at 0.35 lb/MMBtu for each unit). The Division is employing a different baseline that CSU originally utilized (e.g. NOx emissions prior to consideration of OFA). The Division requested additional information from CSU to verify that the 20% ULNB assumption is still valid for all units. CSU noted that Units 6 and 7 will likely be able to achieve the 20% reduction (using the Division's higher NOx emission baseline). However, Unit 5 has an older technology coal mill and other technical issues and would not be able to achieve 20% reduction. Unit 5 has an older mill (ball-type pulverizers vs. the hammermills present at Units 6 and 7), which limits the level of coal fineness. In addition, Unit 5 is a smaller boiler than the other units. In light of these specific technical feasibility issues, the Division used 10% additional reduction efficiency for ULNBs for Unit 5. Therefore, the overall control efficiencies for ULNB+OFA in combination for the three units are 28% for Unit 5 and 36% for Units 6 and 7 respectively.

SNCR: Other Colorado facilities have noted a variety of control ranges for SNCR. The Division used a variety of information, including similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study[22] to conservatively approximate that the Drake boilers can achieve 30% control when SNCR is applied.

*SCR:*CSU approximates that SCR can achieve an approximate 80% NO_x reduction using 2004 – 2005 baseline emissions (or 0.07 lb/MMBtu), determined by URS WD using a survey of a large collection of photographs, and experience in developing retrofit factors for many types of units and configurations at numerous facilities. The Division adjusted the control efficiency percent reduction to reflect the 2006 – 2008 baseline emissions, but kept the resultant 0.07 lb/MMBtu constant. This control efficiency is consistent with EPA's AP-42 emission factor discussion, which estimates SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction.[23,24]

ULNBs/SCR layered approach: CSU evaluated a layered approach of installing ULNBs upstream of the combustion process to reduce NO_x entering the boiler and thus reducing subsequent SCR reduction requirements. This approach will achieve the same NO_x emission reductions as SCR alone and is deemed to be appropriate by the Division.

Table 17 summarizes each available technology and technical feasibility for NO_x control.

Table 17: Drake Units 5, 6, and 7 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO_x Burners (LNB)	50 -56%	Y – installed

[22] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.
[23] 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
[24] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

LNB + OFA	60 – 81%	Y (LNBs are installed on each unit)
Overfire air (OFA)	10 – 25% (alone)	Y
Ultra-low NO_x burners (ULNBs)	26 – 32%	Y
ULNB+OFA	28 – 36%	Y
Selective non-catalytic reduction (SNCR)	~ 30%	Y
Selective catalytic reduction (SCR)	75 – 90%	Y
ULNB/SCR layered approach	75 – 90%	Y
ECO®	n/a	N
RRI	n/a	N
Coal reburn +SNCR	n/a	N

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

OFA: Washington Group International Inc. estimated the cost of overfire air during the course of a pollution control study for the Drake boilers in 2004. The cost estimates were generated using EPRI's IECCOst model. This model uses specific unit data to calculate the cost of controlling emissions and is typically considered to be accurate within ±30%. Overfire air will not require large pieces of new equipment, but instead the costs consist primarily of labor and materials related to modifying the boiler waterwall tubes to allow for new air injection ports and the necessary ductwork, dampers, and instrumentation and control to supply the air from the existing secondary air duct. In a technical support document issued by the Northeast States for Coordinated Air Use Management (NESCAUM) entitled "NO_x Controls for Existing Utility Boilers,"[25] OFA alone ranges from \$410 - \$1,100 per ton NO_x reduced annually for units estimating 15 – 30% NO_x control, which is within the range of Drake's estimated OFA NO_x reductions (20%). The estimates in Table 18, Table 20, and Table 22 are within this range. Therefore, the Division concurs with the OFA cost estimates.

ULNBs: CSU's cost estimate includes the burners, oil or gas lighter systems and controls at burner front, automatic air register adjustment and control drives, flame scanners and controls, all wind box controls including control drawings, all control and burner logic drawings. The estimates do not include burner wind box extensions or stove pipe, ducts installed on top of existing wind boxes, furnace water wall openings, structural steel support for ULNBs beyond supplemental support steel, cost for engineering, supply and construction of wind box extensions, physical modeling, math modeling, or wind box baffling, pulverizer upgrades, burner piping or classifiers for improved coal fineness and required size distribution. CSU notes that some or all of the items must be determined by boiler modeling and pulverizer testing. If all of these are needed, the capital costs could increase by 40 – 70% compared to the base scope listed in Table 19, Table 21, and Table 23. The Division considers CSU's estimated costs more than

[25] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

reasonable, with ULNBs under $1,000/ton which is comparable or lower than LNB costs presented in recent NESCAUM papers.[26, 27]

ULNB+OFA: The Division based cost estimates for this control option assuming that OFA and ULNBs will be installed separately; therefore, the cost for this layering option is a summation of individual annualized costs for OFA and ULNBs for each unit. The Division checked this assumption with CSU on November 8, 2010.

SNCR: 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 Drake boilers.

A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.[28] A similar Colorado facility estimated operating expenses at approximately 81 – 86%.[29] 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.[30]

The Division used information from a similar facility submittal to determine approximate SNCR costs for the Drake boilers since CSU did not have SNCR information.[31] The Division consulted with CSU on this decision to ensure that these boilers are roughly equivalent to the Drake boilers in scope and retrofit difficulty.

The resultant cost effectiveness for SNCR on Units 5, 6, and 7 ranges from $2,700 to $4,400 per ton. 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.[32,33]

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26 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. www.nescaum.org/documents/**nox**-2000.pdf

27 Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

28 ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.

29 CENC, 2009. "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado." Prepared by AECOM.

30 EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

31 CENC, 2009. "NOx Technical Feasibility and Emission Control Costs for Colorado Energy Nations, Golden, Colorado." Prepared by AECOM.

32 Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf

33 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.

EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced.[34] Although the resulting cost estimates for the Drake boilers 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 the estimated cost estimates for SNCR are reasonable.

SCR: CSU estimated the cost for the SCR system(s) using the IECCOST program. This estimate includes the cost of a new ID booster fan, since CSU/URS noted that the current ID fan does not have sufficient capacity to accommodate the additional pressure drop of the SCR retrofit. Recent NESCAUM studies estimate SCR retrofits achieving NO_x emission rates of 0.05 – 0.15 lb/MMBtu and emission reductions of 65 – 85% as costing $2,600 - $7,400 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[35,36] The SCR system estimates for the CSU Drake boilers range from approximately $5,000 - $7,100, which is within the NESCAUM estimates. The Division concurs that CSU cost estimates for SCR controls are reasonable.

ULNBs/SCR layered approach: CSU chose to examine the ULNB/SCR layered approach because the cost of the SCR would be reduced somewhat in this scenario. The reduced costs would be noted in the reactor housing, amount of catalyst required, and the aqueous ammonia storage, handling, and injection. Therefore, this option was examined to determine the significance of the potential cost differential. The Division concurs that this is an appropriate option and may possibly reduce costs.

Table 18, Table 20, and Table 22 illustrate resultant NO_x emissions for each technically feasible control option. Table 19, Table 21, and Table 23 show the NO_x control costs for each unit based on detailed cost analyses. The Division estimated resultant NO_x using annual average reductions for tons of NO_x reduced per year, as noted in Table 2. The Division's experience with power plants suggest that the maximum 30-day rolling average NO_x emission rate is 5-15% higher than the annual average emission rate.

Table 18: Drake Unit 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)
Baseline	---	768	0.38	
Overfire air (OFA)	20	615	0.30	0.35
Ultra-low NOx burners (ULNBs)	26	569	0.28	0.32
ULNBs+OFA	28	553	0.27	0.31
Selective Non-Catalytic Reduction (SNCR)	30	538	0.26	0.30

[34] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[35] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[36] 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.

ULNBs/SCR layered approach	81.5	142	0.070	0.080
Selective Catalytic Reduction (SCR)	81.5	142	0.070	0.080

Table 19: Drake Unit 5 NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Overfire air (OFA)	154	$141,844	$923	$923
Ultra-low NOx burners (ULNBs)	200	$147,000	$736	$112
ULNBs+OFA	215.2	$288,844	$1,342	$9,230
Selective Non-Catalytic Reduction (SNCR)	231	$1,011,324	$4,387	$47,011
ULNB/SCR layered approach	626	$4,467,000	$7,133	$8,732
Selective Catalytic Reduction (SCR)	626	$4,580,349	$7,314	---

Table 20: Drake Unit 6 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,413	0.42	
Overfire air (OFA)	20	1,130	0.33	0.38
Selective Non-Catalytic Reduction (SNCR)	30	989	0.29	0.33
Ultra-low NOx burners (ULNBs)	32	961	0.28	0.32
ULNBs+OFA	36	904	0.27	0.31
ULNBs/SCR layered approach	83.2	237	0.070	0.080
Selective Catalytic Reduction (SCR)	83.2	237	0.070	0.080

Table 21: Drake Unit 6 NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Overfire air (OFA)	283	$104,951	$371	$371
Selective Non-Catalytic Reduction (SNCR)	424	$1,208,302	$2,851	$7,810
Ultra-low NOx burners (ULNBs)	452	$232,800	$515	($34,525)
ULNBs+OFA	509	$337,751	$664	$1,857

ULNBs/SCR layered approach	1,175	$6,182,800	$5,260	$8,226
Selective Catalytic Reduction (SCR)	1,175	$6,340,797	$5,395	---

Table 22: Drake Unit 7 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	2,081	0.39	
Overfire air (OFA)	20	1,665	0.31	0.36
Ultra-low NOx burners (ULNBs)	28	1,498	0.28	0.33
Selective Non-Catalytic Reduction (SNCR)	30	1,457	0.28	0.32
ULNBs+OFA	36	1,332	0.25	0.29
ULNBs/SCR layered approach	80.1	372	0.070	0.080
Selective Catalytic Reduction (SCR)	80.1	372	0.070	0.081

Table 23: Drake Unit 7 NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
Overfire air (OFA)	416	$75,217	$181	$181
Ultra-low NOx burners (ULNBs)	583	$386,000	$662	$1,867
Selective Non-Catalytic Reduction (SNCR)	624	$2,018,575	$3,233	$39,226
ULNBs+OFA	749	$461,217	$616	($12,473)
ULNBs/SCR layered approach	1,708	$8,196,000	$4,797	$5,698
Selective Catalytic Reduction (SCR)	1,708	$8,510,067	$4,981	---

Energy and Non-Air Quality Impacts

OFA: Overfire air does not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

ULNBs: The additional energy required to further pulverize coal is relatively small and is accounted for in CSU's February 2009 submittal. Therefore, ULNBs do not have any significant energy or non-air quality related impacts. Thus, this factor does not influence the selection of this control.

SNCR /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 like SNCR do increase power needs, in the range of 100 – 300 kilowatts (kW) depending on the boiler size, 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. 100 – 300 kW is less than 1.0% of the power generated by the Drake Unit 7 boiler annually, or enough energy to power about 10 homes for a year. These energy requirements are minimal.

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 example, CSU estimates that on Drake 7, the power consumption for a SCR system will be over 700 kW. These energy requirements are moderate (0.5% of Drake 7's gross output).

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. CSU has indicated to the Division that they would prefer to use aqueous ammonia instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on an aqueous ammonia reagent versus an ammonia reagent.

Remaining Useful Life

CSU asserts that the remaining useful life of Drake Units 5, 6, and 7 are each in excess of 20 years, which is the maximum amortization period allowed in the BART analysis. 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 24 shows the number of days pre- and post-control. Table 25 depicts the visibility results (98^{th} 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[37], 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 NO_x BART control technology on a given unit, emission rates for the other pollutants (SO_2 and PM/PM_{10}) 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 all units with NO_x emissions at 0.07 lb/MMBtu and SO_2 emissions at 0.12 lb/MMBtu for Units 6 and 7 and at 0.32 lb/MMBtu for Unit 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 24: 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-hour NOx rates	5	0.619	Rocky Mountain National Park	34	---	---	17	---	---
	6	0.827							
	7	0.710							
NOx Control Scenario	5	0.390		34	34	0	17	15	2
	6	0.390		34	31	3	17	14	3
	7	0.390		34	31	3	17	14	3
OFA	5	0.300*		n/a					
	6	0.330*		n/a					
	7	0.310*		n/a					
ULNBs	5	0.280*		n/a					
	6	0.282*		n/a					
	7	0.283*		n/a					
ULNBs+OFA	5	0.272*		n/a					
	6	0.266*		n/a					

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

	7	0.251*		n/a					
SNCR	5	0.265*		n/a					
	6	0.291*		n/a					
	7	0.275*		n/a					
NOx Control Scenario	5	0.234		34	34	0	17	14	3
	6	0.234		34	31	3	17	14	3
	7	0.234		34	28	6	17	14	3
SCR	5	0.070		34	32	2	17	14	3
	6	0.070		34	27	7	17	14	3
	7	0.070		34	26	8	17	13	4
Combo	5	0.070		34	1	33	17	0	17
	6	0.070							
	7	0.070							

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

Table 25: 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-hour NOx rates	5	0.619	1.84	---	---	---
	6	0.827				
	7	0.710				
NOx Control Scenario	5	0.390	1.79	0.05	3%	n/a
	6	0.390	1.68	0.16	9%	n/a
	7	0.390	1.66	0.18	10%	n/a
OFA	5	0.300*	1.76	0.08	4%	$1,970,053
	6	0.330*	1.66	0.18	10%	$583,061
	7	0.310*	1.61	0.22	12%	$335,791
ULNB	5	0.280*	1.76	0.08	4%	$1,934,212
	6	0.282*	1.64	0.197	11%	$1,181,727
	7	0.283*	1.60	0.24	13%	$1,615,062
SNCR	5	0.265*	1.76	0.08	4%	$12,641,549
	6	0.291*	1.64	0.19	11%	$6,228,362
	7	0.275*	1.59	0.24	13%	$8,272,850
ULNBs+OFA	5	0.272*	1.76	0.08	4%	$3,703,128
	6	0.266*	1.63	0.20	11%	$1,663,798

	7	0.251*	1.58	0.26	14%	$1,794,618
NOx Control Scenario	5	0.234	1.75	0.24	5%	n/a
	6	0.234	1.62	0.24	12%	n/a
	7	0.234	1.57	0.24	15%	n/a
SCR	5	0.070	1.71	0.12	7%	$36,024,194
	6	0.070	1.56	0.27	15%	$22,647,619
	7	0.070	1.47	0.37	20%	$22,091,644
Combo	5	0.070	0.25	1.59	86%	n/a
	6	0.070				
	7	0.070				

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

Step 6: Select BART Control

Based upon its consideration of the five factors summarized herein, the state has determined that NO_x BART for Units 5, 6, and 7 is the following NO_x emission rates:

Drake Units 5 and 6: 0.31 lb/MMBtu (30-day rolling hour average)
Drake Unit 7: 0.29 lb/MMBtu (30-day rolling hour average)

The state assumes that the BART emission limits can be achieved through the installation and operation of ultra low-NOx burners (including over-fire air).

- Unit 5: $1,342 per ton NOx removed
- Unit 6: $664 per ton NOx removed
- Unit 7: 616 per ton NOx removed

The extremely low dollars per ton control costs, leads the state to selecting this emission rate for each of the Drake units. SNCR is not selected as that technology provides an equivalent emissions rate, similar level of NOx reduction coupled with equivalent visibility improvement at a much higher cost per ton of pollutant removed along with potential energy and non-air quality impacts. SCR is not selected as the cost/effectiveness ratios for Units 5 and 6 are too high and the visibility improvement does not meet the criteria guidance described in Chapter 6.4.3 of the Regional Haze SIP (*e.g.* less than 0.50 Δdv)