

**Best Available Retrofit Technology (BART) Analysis of Control Options
For
Public Service Company – Hayden Station**

I. Source Description

Owner/Operator: Public Service Company
 Source Type: Electric Utility Steam Generating Unit
 SCC (EGU): Unit 1: 10100222 Unit 2: 10100226
 Boiler Type: Pulverized Coal, Dry-Bottom, Front-Fired, firing coal (Unit 1 a)
 Pulverized Coal, Dry Bottom, Tangentially-Fired, firing coal (unit 2)

The facility is located four miles east of Hayden, Colorado at 13125 U.S. Highway 40 in Routt County. This facility consists of two (2) steam driven turbine/generator units (Units 1 and 2) and the associated equipment needed for generating electricity. The Unit 1 ignitors utilize either natural gas or No. 2 fuel oil and the Unit 2 ignitors utilize No. 2 fuel oil for startup, shutdown and/or flame stabilization. In addition to the coal fired boilers, other significant sources of emissions at this facility include fugitive emissions from coal handling, ash handling and disposal and vehicle traffic on paved and unpaved roads. Point source emissions of particulate matter include coal crushing and conveying, an ash storage silo, two (2) ash recycle silos (recycle ash used with lime in the spray dryer), two (2) lime storage silos, two (2) ball mill slakers (prepares lime slurry for spray dryer) and two (2) recycle mixers (prepares recycle as slurry for spray dryer). Additional emission units at this facility include two (2) cooling towers. Only Units 1 and 2 are BART-eligible. Table 1 below lists the units at Public Service Company Hayden Station 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.

Table 1: Hayden Boilers Technical Information

	Unit 1	Unit 2
Placed in Service	July 1965	1976
Boiler Rating, MMBtu/Hr for coal	1,963	2,712
Electrical Power Rating, Gross Megawatts	190	275
Description	Riley-Stoker Pulverized Coal Front Fired Dry Bottom, firing coal with natural gas and No. 2 fuel oil used for startup, shutdown and/or flame stabilization.	Combustion Engineering Pulverized Coal Tangentially Fired Dry Bottom, firing coal with No. 2 fuel oil used for startup, shutdown, and/or flame stabilization.
Air Pollution Control Equipment	PM/PM ₁₀ - Reverse-Air Fabric Filter Baghouse NO _x – Low NO _x Burners with Over-Fire Air SO ₂ – Lime Spray Dryer	PM/PM ₁₀ – Reverse-Air Fabric Filter Baghouse NO _x – Low NO _x Burners with Over-Fire Air SO ₂ – Lime Spray Dryer

	All equipment commenced operation in December 1998	All equipment commenced operation in October – December 1999
Emissions Reduction (%)*	NO _x – 54.1% SO ₂ – 82.0% PM – 99.7% PM ₁₀ – 98.8%	NO _x – 33.3% SO ₂ – 79.6% PM – 99.7% PM ₁₀ – 98.9%

*Emissions Reduction estimated by comparing uncontrolled AP-42 factor to actual average emission factor for PM/PM₁₀. For NO_x and SO₂ estimates, CAMD data was used to calculate reductions. See “Hayden APCD Technical Analysis” for further details. Not based on actual testing.

Units 1 and 2 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, SO₂, PM₁₀), and commenced operation in the 15-year period prior to August 7, 1977. These boilers also cause or contribute to visibility impairment at a federal Class I area at or above a 0.5 deciview change; consequently, both boilers are subject-to-BART. Public Service Company (PSCo) submitted a BART analysis to the Division on September 14, 2006 with revisions submitted on November 1, 2006 and January 8, 2007. In response to Division requests, PSCo submitted additional information on May 25 and July 14, 2010. The submittals are included as “PSCo BART Submittals”.

II. Emissions for Units 1 & 2

PSCo estimated that a realistic depiction of anticipated annual emissions for Units 1 and 2, or “Baseline Emissions”, to be conservative, was the average of two previous years (2004, 2005) of emissions data in the September 14, 2006 analysis. 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 Division verified these emissions using Colorado’s Air Pollutant Emission Notices and EPA’s CAMD database. These emissions are summarized in Table 2.

Table 2: PSCo Hayden Units 1 & 2 Emissions

Pollutant	Unit 1		Unit 2	
	Annual Emissions* (tpy)	Annual emissions** (lb/MMBtu)	Annual Emissions* (tpy)	Annual emissions** (lb/MMBtu)
NO _x	3,750	0.415	3,743	0.320
SO ₂	1,172	0.131	1,469	0.127
PM ₁₀	88.0	0.006***	109.3	0.004***

*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 SO₂ emissions.

***The PM₁₀ emission rate is determined from the latest Title V permit compliance stack test (June 2009). These values are as follows: Hayden Unit 1: 0.006 lb/MMBtu Hayden Unit 2: 0.004 lb/MMBtu

III. Units Evaluated for Control

PSCo notes that the Hayden boilers burn Colorado coal that primarily comes from two different mines in northwestern Colorado, the Twenty Mile Mine and the ColoWyo Mine. Coal characteristics are very similar from both of these mines. However, the ColoWyo coal is ranked as sub-bituminous while the Twenty Mile coal is ranked as bituminous (ASTM Method 388). However, PSCo performed an analysis using the Electric Power Research Institute (“EPRI”) NO_x/LOI Predictor software program (Version 2.1) to demonstrate that the more appropriate rating for ColoWyo coal is bituminous. The specifications for these coals are listed below in Table 3. Note that with the exception of moisture content, the coal characteristics are reasonably close for the two coals.

Table 3: Hayden Station Coal Specifications (2004 – 2005)

Coal Mine/Region	Colowyo	Twentymile
Coal Rank Classification	Sub-bituminous, Class A	Bituminous
As Received Analysis		
H ₂ O (Moisture %)	16.8	9.8
Ash (%)	5.82	9.5
Sulfur (%)	0.36	0.49
Nitrogen (%)	1.33	1.65
Heating Value (HHV Btu/lb)	10,450	11,350
EPRI Model NO _x Prediction (lb/MMBtu)	0.46	0.39

Uncontrolled emission factors are outlined in Table 4. The factors are based on firing bituminous coal as well as the highest ash and sulfur content from the two coals for conservative estimates.

Table 4: Uncontrolled emission factors for PSCo Hayden BART-eligible sources¹

Emission Unit	Pollutant (lb/ton)*			
	NO _x	SO ₂	PM (filterable)	PM ₁₀ (filterable)
Hayden Unit 1	22**	18.6	95	21.9
Hayden Unit 2	15**	18.6	95	21.9

*SO₂ and PM/PM₁₀ 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 3.

**Assumed no low-NO_x burners.

IV. BART Evaluation of Units 1 and 2

A. **Sulfur Dioxide (SO₂)**

Step 1: Identify All Available Technologies

Semi-Dry FGD Upgrades – As discussed in EPA’s BART Guidelines², electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not

¹ 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/chiefs/ap42/ch01/final/c01s01.pdf>

² EPA, 2005. Federal Register, 40 CFR Part 51. Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule. Pgs. 39133.

required to remove these controls and replace them with new controls. The Division interprets this to include fuel switching to natural gas, which would require significant boiler modifications, including removing the semi-dry FGD.

However, based on Appendix Y [70 FR 39171], the following dry scrubber upgrades should be considered for Hayden Units 1 and 2 if technically feasible. These upgrades include:

- Use of performance additives
- Use of more reactive sorbent
- Increase the pulverization level of sorbent
- Engineering redesign of atomizer or slurry injection system
- Additional equipment and maintenance: In the May 25, 2010 response to the Division, PSCo noted that Hayden Units 1 and 2 could potentially achieve a new reduced 30-day average emission rate limit of 0.13 lbs/MMBtu by conducting changes to the dry scrubber systems, so this option will be evaluated as part of possible semi-dry FGD upgrades.

The current Operating Permit limits are depicted in Table 5.

Table 5: Hayden Units 1 & 2 SO₂ Operating Permit Limits

	SO ₂ limits (lb/MMBtu)			Reduction (%) Required
	3-hr rolling	30-day rolling	90-day rolling	30-day rolling
Units 1 & 2	1.2	0.160	0.130	82 (rounded)

Step 2: Eliminate Technically Infeasible Options

At the Division's request, PSCo submitted an SO₂ upgrade analysis to the Division on May 25, 2010 regarding potential upgrades for the LSDs installed on Hayden Units 1 and 2. The following summarizes PSCo's submittal and the Division's analysis of the information provided.

FGD: Flue gas desulfurization removes SO₂ from flue gases by a variety of methods. 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.

Dry FGD Upgrades: 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 plants³. SDA systems are typically utilized at units that burn lower-sulfur coal in the western U.S., where water resources are limited. 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.

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.

PSCo installed lime spray dryers (LSDs) in connection with baghouses on Hayden Units 1 and 2 1998 and 1999, respectively. PSCo notes that both of these dryers currently achieve greater than 80% removal, with actual annual averages of 0.13 lbs SO₂/MMBtu (each unit) in comparison with the permit limits⁴ depicted in Table 5. This system exceeds EPA's presumptive limits stated in 40 CFR Part 51 Appendix Y of 0.15 lb/MMBtu, although the current permit limit is higher than the presumptive limits.

At the Division's request, PSCo submitted a SO₂ upgrade analysis to the Division on May 25, 2010 regarding potential upgrades for the lime spray dryer systems at Hayden Station. Hayden's Babcock and Wilcox (B&W) lime spray dryers that use a single atomizer per scrubber module design that sprays a mixture of lime and recycled ash into the flue gas. This atomized mist then dries, reacts with SO₂ in the flue gas and is collected in the baghouse.

PSCo examined potential upgrades to the Hayden dry scrubbers, with the following results:

-Use of performance additives: The supplier (Babcock & Wilcox) of PSCo's Colorado dry scrubbing equipment does not recommend the use of any performance additive. PSCo is aware of some additive trials, using a chlorine-based chemical, which have been used on dry scrubbers. Chlorides are used to slow the drying time of the fly ash/lime mixture used to capture the gaseous SO₂. The chemistry of the calcium sulfate/sulfite reaction is much more effective when liquid water droplets exist. By slowing the drying time the theory is that the lime sorbent will be more efficient and the lime use could be decreased to obtain the same SO₂ reduction capability of the equipment unless the unit is limited on the total amount of lime slurry injection. There are cases on units that use high sulfur coal (significantly greater than 1.2 lbs/MMBtu) where the total amount of lime slurry injection is limited by the solids content of the slurry. When the total limit injection for a unit is limited, additives may allow some increase in SO₂ removal. However, because the Hayden boilers burn low sulfur western coals, PSCo is not limited on lime slurry injection and the use of performance additives on the scrubbers would not be expected to increase the SO₂ removal. Based on the information provided by PSCo, the Division agrees that the use performance additives are not likely to increase SO₂ removal and therefore warrants no further consideration.

-Use of more reactive sorbent: All PSCo dry scrubbers were designed to use a highly reactive lime with 92% calcium oxide content. The scrubbers were also designed to inject fly ash to maximize available surface area and allow efficient lime reagent use. Some dry scrubbers used by other companies were designed to use a lower quality lime, a dry hydrated lime product, or operate on lime without fly ash. On these scrubbers, the option of using a higher quality lime or injecting fly ash possibly could improve SO₂ removal. The only other common reagent option for a dry scrubber is sodium-based products which are more reactive than freshly hydrated lime. Sodium has a major side effect of converting some of the NO_x in the flue gas into NO₂. Since NO₂ is a visible gas, large coal-fired units can generate a visible brown/orange plume at high SO₂ removal rates, such as those experienced at Hayden.

⁴ Colorado Operating Permit Number 96OPROB132 Last Revised 5/14/10. Pgs. 6, 9.

Lime is the reagent of choice in modern spray dryer systems on utility scale units. PSCo is aware of only one exception that was designed to use sodium carbonate to remove SO₂. The Coyote Station, a 420MW unit located near Beulah, North Dakota and operated by Otter Tail Power Company, was placed in service in 1981. The spray dryer was supplied by Rockwell and used rotary atomizers. The unit was designed to obtain 70% SO₂ removal. This unit was reported to have a visible plume at times likely due to the conversion from NO to NO₂ due to the sodium reagent. This unit was converted from sodium carbonate to lime after a number of years in service. PSCo verified with the two major suppliers of utility sized spray dryers, B&W and Alstom, and confirmed that there are no other operating utility spray dryers in the United States. B&W also states that in theory the sodium based reagents are more reactive as they have a slower drying time than lime reagents. However, because of their slower drying time, the spray dryer absorber would need to be larger to ensure the product was dry when leaving the scrubber. Thus, the use of sodium reagent in a unit designed for lime would not allow higher SO₂ removal and it may not even be possible to convert to a sodium reagent with the existing equipment.

PSCo is using a highly reactive reagent that maximizes SO₂ removal; there are no known acceptable reagents without side effects that would allow additional SO₂ removal in the dry scrubbing systems present at Hayden Station. The Division agrees with PSCo's assessment and considers that use of a more reactive sorbent does not warrant further consideration.

-Increase the pulverization level of sorbent: The Hayden dry scrubbers are designed with either horizontal or vertical ball mills to obtain optimum particulate size and reduce lime grit generation. There have been some technical papers presented by pulverizer suppliers, that state vertical ball mills may provide a smaller particulate size and reduce lime use. PSCo's experience is that there is no SO₂ removal benefit in using vertical ball mills versus horizontal ball mills and there is also no measurable reduction in lime use. Since PSCo already uses the best available grinding technologies, the Division would agree that changes to the design of the atomizers are unlikely to result in a higher SO₂ removal.

-Engineering redesign of atomizer or slurry injection system: The Hayden dry scrubber systems are from B&W and use the same size and general design atomizer, a Model F800. While there are differences in the motor size and exact atomizer wheel construction that relate to the total slurry injection rate, the atomizer design is based on the vendor's experience to maximize both SO₂ removal and lime use efficiency. B&W offers no upgrade in atomizer design to improve SO₂ removal. There are certain third-party suppliers who offer different atomizer nozzle designs that they claim can reduce lime use or provide longer maintenance life. To PSCo's knowledge, no vendors claim an improved SO₂ removal. PSCo has tried some of these different nozzle designs and doesn't believe any of the designs improve the SO₂ removal level, although some have improved wear life and reduced maintenance costs.

However, PSCo provided to the Division upon additional request (July 14, 2010) additional information stating that an additional scrubber module (i.e. atomizer) would be required for each unit as well as additional spare parts and maintenance personnel in order to meet a lower emission limit. Therefore, this option is technically feasible.

-Additional equipment and maintenance: PSCo reviewed actual operating experience on Hayden along with possible changes to the systems necessary to achieve lower emission rates on a 30-day average basis. The primary factors that affect SO₂ control efficiency for short-term averages are start-ups, equipment malfunctions, and low load operation. In order to begin injecting lime/recycle ash slurry into the scrubber, a minimum inlet scrubber temperature must be achieved so the lime/recycle ash slurry dries when it hits the hot flue gas. When the scrubber inlet temperature is below this minimum level, the lime slurry drops out in the scrubber and forms concrete-like deposits that eventually plug the scrubber vessel. This situation actually occurred while operating PSCo's Comanche Unit 2 and Valmont Unit 5 scrubbers and resulted in extended maintenance outages to clean the scrubbers. During unit start-ups, it can take anywhere from 12-24 hours to get the inlet scrubber temperatures up to the level necessary for safe lime slurry injection.

During these start-up periods, SO₂ emissions rates are at uncontrolled levels based on the sulfur content in the coal. Typically, if the unit only starts once during a 30-day period, operators can over-control SO₂ by running the scrubber below the 30-day average emission rate to "make-up" for higher emission rates during start-up. If the unit has more than one start-up in a 30-day period, which certainly happens with older units, it becomes nearly impossible to scrub hard enough to achieve the 30-day rolling emission rate limits. The same situation occurs under low load operation, especially during winter months. Inlet temperature to the baghouse due to air heater in-leakage can approach minimum acceptable levels, thus lowering overall SO₂ control efficiency during low load operation. PSCo coal-fired units will be required to cycle (under 60% load) more in the future to accommodate the intermittent nature of ever increasing wind generation on the electric grid and thus requiring the boilers to operate more frequently at low loads.

Based on a review of actual operating data and the factors noted above that affect short-term average SO₂ emission rates, PSCo believes Hayden Units 1 and 2 can achieve a lower 30-day average emission rate limit of 0.13 lbs/MMBtu as BART. This is currently the 90-day average emission limit for these units. In order to meet this lower limit on a 30-day average basis, the plant needs to purchase additional spare atomizer parts and increase annual operating and maintenance due to increased labor and reagent requirements.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

PSCo provided the Division 30-day rolling average control estimates. In the Division's experience, 30-day SO₂ rolling average emission rates are expected to be approximately 5% higher than the annual average emission rate. The Division projected an annual average emission rate at 5% for Hayden to determine control efficiencies and annual reductions.

The Division has reviewed the data supplied by PSCo as well as other control techniques applied to pulverized coal boilers. A Division review of the EPA's RBLC revealed recent BACT SO₂ 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.

Engineering redesign of atomizer or slurry injection system: At the Division’s request, PSCo sent cost information regarding the requirements for an additional scrubber module on July 14, 2010 in order to meet a SO₂ 30-day rolling emission limit of 0.08 lb/MMBtu, or 90% control efficiency (pre-control). This upgrade/redesign will result in control efficiencies of 41.7% and 40.1% beyond the current reductions shown in Table 1 on Units 1 and 2, respectively. Using this information, the Division calculated the resultant control effectiveness using the baseline and annual emissions for each unit. See “Hayden APCD Technical Analysis” for more information.

Dry FGD Upgrade – Additional equipment and maintenance: To evaluate the control effectiveness of tightening the 30-day rolling emission limits on Hayden Units 1 and 2, the Division used the annual baseline emissions, the average annual operating hours (2006 – 2008), and the daily heat input (MMBtu/day) to determine the emission rates at 0.13 lb/MMBtu and calculated the resultant control effectiveness and annual emissions for each unit.

Table 6 summarizes each available technology and technical feasibility for SO₂ control.

Table 6: Hayden Units 1 and 2 SO₂ Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Dry FGD Upgrades		
Use of performance additives	n/a	N
Use of more reactive sorbent	n/a	N
Increase pulverization level of sorbent	n/a	N
Engineering redesign of atomizer or slurry injection system	~40 – 42%	Y
Additional equipment and maintenance	~3 - 5%	Y

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

Engineering redesign of atomizer or slurry injection system: The Division calculated cost estimates for an additional scrubber module – based on total capital and operating and maintenance costs provided in PSCo’s July 14, 2010 letter. PSCo stated that Hayden Station will need for an additional module on each unit as well as estimated spare parts and additional maintenance personnel (i.e. O&M costs). PSCo estimated capital costs for Unit 1 at \$37,000,000 and Unit 2 at \$43,000,000 and operating & maintenance costs at \$650,000 and \$750,000 for Units 1 and 2, respectively. These costs are determined based on meeting a more stringent 30-day rolling limit of 0.08 lb/MMBtu for each unit.

Dry FGD Upgrade – Additional equipment and maintenance: The Division calculated cost estimates for dry FGD upgrade – additional equipment and maintenance – based on total capital and operating and maintenance costs provided in PSCo’s May 25, 2010 letter. PSCo stated that Hayden Station will need spare atomizer parts at a cost of \$330,000 along with increased annual operating and maintenance costs of \$220,000 per year for reagent and labor to meet the more

stringent 30-day rolling SO₂ emission limit of 0.13 lbs/MMBtu. This cost analysis was conducted to demonstrate the impact of meeting the more stringent limit only. Table 7, Table 8, Table 9, and Table 10 show the SO₂ control cost per unit.

Table 7: Hayden Unit 1 Control Resultant SO₂ Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,172	0.131	
Dry FGD Upgrade – Additional Equipment and Maintenance	5.2%	1,111	0.124	0.130
Additional Scrubber Module	41.7%	684	0.076	0.080

Table 8: Hayden Unit 2 Control Resultant SO₂ Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,469	0.127	
Dry FGD Upgrade – Additional Equipment and Maintenance	2.7%	1,430	0.124	0.130
Additional Scrubber Module	40.1%	880	0.076	0.080

Table 9: Hayden Unit 1 SO₂ Cost Effectiveness

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
Dry FGD Upgrade – Additional Equipment and Maintenance	61	\$141,150	\$2,317	\$2,317
Additional Scrubber Module	488	\$4,142,538	\$8,490	\$9,370

Table 10: Hayden Unit 2 SO₂ Cost Effectiveness

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
Dry FGD Upgrade – Additional Equipment and Maintenance	39	\$141,150	\$3,626	\$3,626
Additional Scrubber Module	589	\$4,808,896	\$8,164	\$8,485

Energy and Non-Air Quality Impacts

There are no energy and non-air quality impacts related to tightening the emission limit for SO₂ beyond the acquisition of additional reagent. Thus, this factor does not influence the selection of controls.

Remaining Useful Life

PSCo asserts that the remaining useful life of Hayden Units 1 and 2 are each in excess of 20 year, 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 11 shows the number of days pre- and post-control. Table 12 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 protocol⁵, 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 SO₂ BART control technology on a given unit, emission rates for the other pollutants (NO_x and PM/PM₁₀) 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 Units 1 and 2 with NO_x emissions at 0.07 lb/MMBtu and SO₂ emissions at 0.12 lb/MMBtu.

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.

⁵ Colorado Air Pollution Control Division, Technical Services Program, 2010. "Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis."

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

SO ₂ Control Scenario	Boiler(s)	SO ₂ Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals		Δ days	3-year totals		Δ days
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hr SO ₂ rates	1	0.339	Rocky Mountain National Park	236	---	---	155	---	---
	2	0.402							
Dry FGD Upgrade	1	0.160*		n/a					
	2	0.160*		n/a					
Dry FGD Upgrade	1	0.130		236	228	8	155	147	8
	2	0.130		236	224	12	155	143	12
Additional Scrubber Module	1	0.100		236	228	8	155	146	9
	2	0.100		236	223	13	155	143	12
Additional Scrubber Module	1	0.070		236	228	8	155	146	9
	2	0.070		236	223	13	155	142	13
Combo	1	0.070							
	2	0.070		236	57	179	155	6	149

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

Table 12: Visibility Results – SO₂ Control Options

SO ₂ Control Scenario	Boiler(s)	SO ₂ Emission Rate (lb/MMBtu)*	Output (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	(\$/dv)
Max 24-hr SO ₂ rates	1	0.339	3.627	---	---	---
	2	0.402				
Dry FGD Upgrade	1	0.160*	3.540	0.09	2%	n/a
	2	0.160*	3.445	0.18	5%	n/a
Dry FGD Upgrade	1	0.130	3.525	0.10	3%	\$1,383,820
	2	0.130	3.422	0.21	6%	\$688,535
Additional Scrubber Module	1	0.100	3.505	0.12	3%	\$33,955,232
	2	0.100	3.395	0.23	6%	\$20,727,999
Additional Scrubber Module	1	0.070	3.485	0.14	4%	n/a
	2	0.070	3.367	0.26	7%	n/a

Combo	1	0.120	0.91	2.72	75%	n/a
	2	0.120				

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “Hayden 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 SO₂ BART the following SO₂ emission rates:

Hayden Unit 1: 0.13 lb/MMBtu (30-day rolling average)
 Hayden Unit 2: 0.13 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the operation of existing lime spray dryers (LSDs). The state evaluated the option of tightening the emission limit for Hayden Units 1 and 2 and determined that a more stringent 30-day rolling SO₂ limit of 0.13 lbs/MMBtu represents an appropriate level of emissions control for semi-dry FGD control technology. The tighter emission rate for both units is achievable with a negligible investment and the facility operator has offered to undertake these actions to allow for refinement of the emissions rate appropriate for this technology at this source despite the lack of appreciable modeled visibility improvement, and the state accepts this.

B. Filterable Particulate Matter (PM₁₀)

Hayden Units 1 and 2 are each equipped with reverse-air fabric filter baghouses to control PM/PM₁₀ 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.

Table 13 shows the most recent stack test data (2009). Real-time data demonstrates that these baghouses are meeting >99% control. The Title V permit limit is 0.03 lb/MMBtu. The most recent stack test data is used to determine compliance with the permit limit, which at a minimum, occurs every five years, and more frequently depending on the results.

Table 13: Hayden Units 1 and 2 Stack Test Results (2009)

Pollutant	Unit 1 (lb/MMBtu)	Unit 2 (lb/MMBtu)
Filterable PM ₁₀	0.006	0.004
PM ₁₀ Control efficiency	99.85%	99.91%

A Division review of EPA’s RBLC revealed recent BACT PM/PM₁₀ 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 above stack test results 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.

Both boilers must meet the PM emission standard of 0.03 lb/MMBtu in accordance with the Long-Term Strategy Review and Revision of Colorado’s SIP for Class I Visibility Protection Part I: Hayden Station Requirements (8/15/96), as approved by EPA at 62 FR 2305 (1/16/97), Section VI.C.V.8.c.ii(2).

The state has determined that the emission limit of 0.03 lb/MMBtu (PM/PM₁₀) represents the most stringent level of available control for PM/PM₁₀. The units are exceeding a PM control efficiency of 95%, and the state has selected this control technology and emission limit for PM/PM₁₀ as BART. 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/PM₁₀ is not needed for Hayden Units 1 and 2.

C. Nitrogen Oxide (NO_x)

Step 1: Identify All Available Technologies

PSCo identified three options for NO_x control:

Low NO_x burners (next generation)

Selective Non-Catalytic Reduction (SNCR)

Selective Catalytic Reduction (SCR)

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

Electro-Catalytic Oxidation (ECO)®

Rich Reagent Injection (RRI)

Rotating overfire Air (ROFA)

Separated overfire Air (SOFA)

Low NO_x Burners (LNB)

LNB + SOFA

Coal reburn +SNCR

Step 2: Eliminate Technically Infeasible Options

Low NO_x burners (PSCo – LNB): PSCo evaluated low NO_x burner upgrades for Hayden Units 1 and 2, completing studies in July 2006. Units 1 and 2 currently have first-generation low NO_x burners and over-fire air systems. The combustion modifications include upgrades to these existing low NO_x burners rather than complete burner replacements. In addition, changes to the over-fire air systems were also needed to achieve further NO_x reductions on these units. LNB upgrades are technically feasible for Hayden Units 1 and 2.

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. SCNR is considered a technically feasible alternative for Hayden Units 1 and 2.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH₃) 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 a lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for Hayden, two retrofit SCR systems, the 0.07 lb/MMBtu controlled NO_x value is more expected. The SCR reaction occurs within the temperature range of 550°F to 850°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. PSCo economically evaluated a high-dust SCR arrangement. SCR is a technically feasible alternative for Hayden Units 1 and 2.

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 boiler⁶ 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 boilers⁷ and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Units 1 and 2.

LNB/ROFA®/SOFA/LNB+SOFA: Hayden Units 1 and 2 are already equipped with low NO_x burners with over-fire air (LNB+OFA) as part of a consent decree entered by the District Court on August 19, 1996, Civil Action 93-B-1749 and adopted into revisions to Colorado's Visibility SIP, specified in a document entitled "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Hayden Station Requirements," dated August 15, 1996. Table 1 illustrates that these systems achieve 49.5% and 43.3% NO_x reductions (based on actual emissions) on Units 1 and 2, respectively.

ROFA® injects air into the furnace first to break up the fireball and then to create a cyclonic gas flow to improve combustion. ROFA® differs from OFA in that ROFA® utilizes a booster fan to

⁶ Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx

⁷ Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. <http://www.ftek.com/apcRRI.php>

increase the velocity of air to promote mixing and to increase the retention time in the furnace. To date, ROFA® has only been installed as a retrofit technology on units firing eastern bituminous coals.

Based on data published by the manufacturer, ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load⁸. While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+SOFA and is not expected to increase emissions reductions for Hayden Units 1 and 2. Since ROFA® technology would not be expected to provide better emissions performance than the LNB+SOFA baseline for these units, ROFA® technology is not considered further in this 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/MMBtu⁹. 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

PSCo provided the Division 30-day rolling average control estimates. The Division, from experience and other state BART proposals¹⁰, determined that 30-day NO_x rolling average emission rates are expected to be about 5 -15% higher than the annual average emission rate. The Division projected an annual average emission rate at 15% for Hayden to determine control efficiencies and annual reductions.

Low NO_x burners (PSCo – LNB): PSCo stated in their April 20, 2010 submittal that Hayden Units 1 and 2 can meet a 30-day rolling limit of 0.30 lb/MMBtu and 0.24 lb/MMBtu respectively with upgraded low NO_x burner systems. The baselines from Table 2 show that Hayden Unit 1 baseline NO_x emissions are 0.415 lb/MMBtu and Unit 2 baseline NO_x is 0.320 lb/MMBtu. Therefore, the control effectiveness for upgraded low NO_x systems for Unit 1 is 37.1% and Unit 2 is 34.8%. As shown in Table 1, the current low-NO_x burners with overfire air systems achieve 54.1% and 31.3% control respectively. These upgrade control estimates are greater than EPA's AP-42 emission factor table, which estimate LNB with OFA as achieving 40 – 60% reduction.¹¹ In a recent AWMA study, wall-fired boilers burning sub-bituminous coal fitted with LNB+OFA system achieved NO_x reductions from 40 – 80.9% (similar to Hayden Unit 1). Tangential-fired boilers achieved NO_x reductions ranging from 11.3 – 74.4%.¹² With such wide control

⁸ Nalco-Mobotec, ROFA Technology, 1992-2009, <http://www.nalcomobotec.com/technology/rofa-technology.html>

⁹ Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NO_x Control and Combined NO_x/SO₂ Control on an Industrial & Utility Boilers."

<http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf>

¹⁰ State of North Dakota BART Determination for Leland Olds Station Units 1 and 2. Page 16.

¹¹ 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>

¹² Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

efficiency ranges, the Division concludes that the 88.9% and 66.1% (pre-control) reductions estimated by PSCo are reasonable.

SNCR: PSCo stated in their April 20, 2010 submittal that Hayden Units 1 and 2 can meet a 30-day rolling limit of 0.30 lb/MMBtu and 0.21 lb/MMBtu respectively by installing SNCR on each boiler. Therefore, the control effectiveness for SNCR on Unit 1 is 37.1% and Unit 2 is 43.0%. These control effectiveness estimate is consistent with EPA's SNCR Air Pollution Control Technology Fact Sheet between 30 – 50% control efficiency for tangentially fired boilers. Control effectiveness has been historically noted to be lower for wall fired boilers similar to Unit 1. Therefore, the Division concludes that the reductions estimated by PSCo are reasonable.

SCR: PSCo stated in their April 20, 2010 submittal that Hayden Units 1 and 2 can meet a 30-day rolling limit of 0.08 lb/MMBtu and 0.07 lb/MMBtu respectively by installing SCR on each boiler. Therefore, the control effectiveness for SCR on Unit 1 is 83.2% and Unit 2 is 81.0%. 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.^{13,14}

Table 14 summarizes each available technology and technical feasibility for NO_x control.

Table 14: Hayden Units 1 and 2 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Low NO _x Burner (LNB) Upgrade	~35 - 37%	Y
SNCR	20 – 50%	Y
SCR	75 – 90%	Y
Electro-Catalytic Oxidation (ECO)®	n/a	N
Rich Reagent Injection (RRI)	n/a	N
Low NO _x Burners (LNB)	10-30%	Y – installed
LNB + OFA	25-45%	Y – installed
Air Staging – overfire air (OFA)	5-40%	Y – installed
Rotating overfire air (ROFA)	45 – 65%	N
Coal reburn+SNCR	n/a	N

¹³ 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>

¹⁴ Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.

Step 4: Evaluate Impacts and Document Results

Cost of Compliance

Low NO_x burners (PSCo – LNB)/SNCR/SCR: PSCo completed engineering studies in July 2006 to evaluate the cost of combustion controls on Hayden Units 1 and 2. These cost estimates, in 2006 dollars, were based on vendor data and not on actual bids with performance guarantees. PSCo used the Coal Utility Environmental Cost Workbook (CUECost) to develop cost estimates for capital and annual costs, an EPA-approved methodology to estimate rough order-of-magnitude (ROM) cost estimates for air pollution control systems installed on coal-fired power plants ($\pm 30\%$).¹⁵ PSCo provided CUECost input files at the Division's request on April 20, 2010. PSCo used this program for LNB, SNCR, and SCR system estimates. The Division concurs that CUECost is an appropriate methodology for determining cost effectiveness regarding these control technologies.

LNB: In reviewing PSCo's estimates, the Division found that the ratio of annual costs to the total costs for LNBs, which at 11.7% is consistent with an EPA assessment that concluded that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments.¹⁶ Therefore, the Division concludes that PSCo's estimates for LNBs are reasonable.

SNCR: A typical breakdown of annualized costs for SNCR on industrial boilers will be 15 – 25% for capital recovery and 65 – 85% for operating expenses.¹⁷ The PSCo-estimated SNCR costs for operating expenses are 74% and 77% for Hayden Units 1 and 2 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.¹⁸

The cost effectiveness for SNCR on Units 1 and 2 is about \$1,000 and \$1,200 per ton, respectively. Recent NESCAUM studies estimate SNCR retrofits on tangentially fired boilers (similar to Unit 2) 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,

¹⁵ 2009, Yelverton, William H. "Coal Utility Environmental Cost (CUECost) Workbook Development Documentation Version 5.0. Prepared by: ARCADIS, 4915 Prospectus Drive, Suite F, Durham, NC 27713. Prepared for: U.S. Environmental Protection Agency, Office of Research and Development, Air Pollution Prevention and Control Division, Research Triangle Park, NC 27711.

¹⁶ 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.

¹⁷ ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.

¹⁸ EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." <http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

depending on initial capital costs and capacity factor.^{19,20} This same study estimate SNCR retrofits on wall fired boilers (similar to Unit 1) achieving 0.50 – 0.65 lb/MMBtu and emission reductions of 30 – 50% as costing \$590 - \$1,100 per ton of NO_x reduced, depending on initial capital costs and capacity factor. It should be noted that PSCo is estimating resultant emission rates lower than 0.30 lb/MMBtu for both boilers. EPA's SNCR Fact Sheet cites SNCR as costing from \$400 - \$2,500 per ton of NO_x reduced.²¹ PSCo's estimates are within this range. Therefore, the Division concludes that PSCo's cost estimates for SNCR are reasonable.

SCR: 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.^{22,23} In reviewing PSCo's estimates, the Division found that the ratio of annual costs to the total costs for LNBs, which at 17% is higher than an EPA assessment that concluded that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments.²⁴ However, PSCo's cost estimates are within the NESCAUM study ranges, so the Division concludes that PSCo's cost estimates for SCR are reasonable.

Table 15, Table 16, Table 17, and Table 18 depict controlled NO_x emissions and control cost comparisons.

Table 15: Hayden Unit 1 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	---	3,750	0.415	
LNB*	37.1	2,359	0.261	0.300
SNCR*	37.1	2,359	0.261	0.300
SCR**	83.2	630	0.070	0.080

*Determined based on difference between baseline (2006 – 2008) and PSCo's expected emission rates

¹⁹ Neuffer, Bill – ESD/OAQPS, 2003. “NO_x Controls for Existing Utility Boilers.”

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

²⁰ Amar, Praveen, 2000. “Status Report on NO_x 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.

²¹ EPA, 2003. “SNCR Air Pollution Control Technology Fact Sheet.” <http://www.epa.gov/ttn/catc/dir1/fsnscr.pdf>

²² Neuffer, Bill – ESD/OAQPS, 2003. “NO_x Controls for Existing Utility Boilers.”

<http://www.epa.gov/ttn/nsr/gen/u3-26.pdf>

²³ Amar, Praveen, 2000. “Status Report on NO_x 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.

²⁴ 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.

**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

Table 16: Hayden Unit 2 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	---	3,743	0.320	
LNB*	34.8	2,441	0.209	0.240
SNCR*	43.0	2,134	0.183	0.210
SCR**	81.0	711	0.061	0.070

*Determined based on difference between baseline (2006 – 2008) and PSCo's expected emission rates

**The Division calculated SCR reductions using a consistent baseline whereas PSCo uses an adjusted baseline depending on the control technology which results in different control costs.

Table 17: Hayden Unit 1 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
LNB	1,391	\$572,010	\$411	\$411
SNCR	1,391	\$1,353,500	\$973	---
SCR	3,120	\$10,560,612	\$3,385	\$5,326

Table 18: Hayden Unit 2 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost (\$)	Cost Effectiveness (\$/ton)	Incremental Cost (\$/ton)
Baseline	0	\$0	\$0	---
LNB	1,303	\$992,729	\$762	\$762
SNCR	1,610	\$1,893,258	\$1,176	\$2,934
SCR	3,032	\$12,321,491	\$4,064	\$7,331

Energy and Non-Air Quality Impacts

LNB: There are no known non-air quality impacts associated with upgrades on low-NO_x burner systems. Energy impacts are not significant. 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 such as 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 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. These energy requirements are moderate.

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.

Remaining Useful Life

PSCo 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 19 shows the number of days pre- and post-control. Table 20 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 protocol²⁵, 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 (SO₂ and PM/PM₁₀) and other BART-eligible units are held constant at pre-control levels. For BART

²⁵ Colorado Air Pollution Control Division, Technical Services Program, 2010. “Supplemental BART Analysis CALPUFF Protocol for Class I Federal Area Visibility Improvement Modeling Analysis.”

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 Units 1 and 2 with NO_x emissions at 0.07 lb/MMBtu and SO₂ emissions at 0.12 lb/MMBtu.

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

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals		Δdays	3-year totals		Δdays
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv		Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	
Max 24-hr NO _x rates	1	0.610	Mt. Zirkel Wilderness Area	236	---	---	155	---	---
	2	0.367							
NO _x Scenario	1	0.390		236	227	9	155	131	24
	2	0.280		236	230	6	155	144	11
NO _x Scenario	1	0.300		236	218	18	155	125	30
	2	0.210		236	226	10	155	137	18
LNB	1	0.261*		n/a					
	2	0.209*		n/a					
SNCR	1	0.261*		n/a					
	2	0.183*		n/a					
SCR	1	0.070		236	188	48	155	91	64
	2	0.070		236	213	23	155	116	39
Combo	1	0.070		236	57	179	155	6	149
	2	0.070							

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

Table 20: Visibility Results – NO_x Control Options

NO _x Control Scenario	Boiler(s)	NO _x Emission Rate (lb/MMBtu)*	Proposed Limit (@ 98 th Percentile Impact)	98 th Percentile Impact Improvement	98 th Percentile Improvement from Maximum	Cost Effectiveness
			(deciviews)	(deciviews)	(%)	(\$/deciview)
Max 24-hr	1	0.610	3.63	---	---	---

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NO _x rates	2	0.367				
NO _x Scenario	1	0.390	3.13	0.50	14%	n/a
	2	0.280	3.42	0.20	6%	n/a
NO _x Scenario	1	0.300	3.02	0.60	17%	n/a
	2	0.210	3.23	0.40	11%	n/a
LNB	1	0.261*	2.94	0.69	19%	\$832,621
	2	0.209*	3.23	0.40	11%	\$2,500,576
SNCR	1	0.261*	2.94	0.69	19%	\$1,970,161
	2	0.183*	3.15	0.48	13%	\$3,969,094
SCR	1	0.070	2.51	1.12	31%	\$9,462,914
	2	0.070	2.77	0.85	24%	\$14,427,975
Combo	1	0.070	0.91	2.72	75%	n/a
	2	0.070				

* Denotes that output was interpolated by the Division and is not an actual modeled output. See “Hayden 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 is the following NO_x emission rates:

Hayden Unit 1: 0.08 lb/MMBtu (30-day rolling average)
 Hayden Unit 2: 0.07 lb/MMBtu (30-day rolling average)

The state assumes that the BART emission limits can be achieved through the installation and operation of selective catalytic reduction (SCR). For these emission limits, the cost per ton of emissions removed, coupled with the estimated visibility improvements gained, falls within the guidance criteria presented in Chapter 6 of the Regional Haze State Implementation Plan:

- Unit 1: \$3,385 per ton NO_x removed; 1.12 deciview of improvement
- Unit 2: \$4,064 per ton NO_x removed; 0.85 deciview of improvement

The dollars per ton control costs, coupled with notable visibility improvements leads the state to this determination. The NO_x emission limits of 0.08 lb/MMBtu (30-day rolling average) for Unit 1; and 0.07 lb/MMBtu (30-day rolling average) for Unit 2; are technically feasible and have been determined to be BART for Hayden Units 1 and 2.