Reasonable Progress (RP) Four-Factor Analysis of Control Options For Tri-State Generation & Transmission Association, Inc. – Nucla Station

I. Source Description

Owner/Operator:	Tri-State Generation & Transmission Association, Inc.
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	10100218
Boiler Type:	Atmospheric Circulating Fluidized Bed

The Tri-State Generation Transmission & Association, Inc. (Tri-State) Nucla Station is located in Montrose County approximately 3 miles southeast of the town of Nucla, Colorado. The Nucla Station consists of one coal fired steam driven electric generating unit (Unit 4), with a rated electric generating capacity of 110 MW (gross), which was placed into service in 1987. The boiler is equipped with a fabric filter (baghouse) system for controlling particulate matter (PM) emissions, and limestone injection into the fluidized bed for the removal of sulfur dioxide (SO_2). The boiler is designed for the reduction of NO_x formation and a small Selective Non-Catalytic Reduction (SNCR) system using anhydrous ammonia injection is used for NO_x trim to ensure compliance with annual NO_x limits. Additionally, the facility includes a number of fugitive dust sources.

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the Nucla facility, and information about similar facilities to determine RP for PM and SO_2. EPA's BART guidelines recommend that states utilize a five step process for determining BART for EGU sources above 750 MW. Although this five step process is not required for making Reasonable Progress (RP) determinations, the Division has elected to largely follow it in RP. This is for ease of reference, and because the statutory factors that must be considered in making BART and RP determinations are largely the same.

The Division has elected to set a *de minimis* threshold for actual baseline emissions for evaluating reasonable progress units at each facility equal to the federal Prevention of Significant Deterioration levels. The Division defines "unit" as an Air Pollutant Emission Notice (APEN) subject source, or a stationary source, defined as "any building, structure, facility, equipment, or installation, or any combination thereof belonging to the same industrial grouping that emit or may emit any air pollutant subject to regulation under the Federal Act that is located on one or more contiguous or adjacent properties and that is owned or operated by the same person or by persons under common control[1]."

[1] Colorado Department of Public Health and Environment. Air Quality Control Commission Common Provisions Regulation 5 CCR 1001-2. Amended December 17, 2009. Effective January 30, 2010. Page 19.

These *de minimis* levels are as follows:

- NO_x – 40 tons per year
- SO_2 – 40 tons per year
- PM_{10} – 15 tons per year

The Nucla facility originally consisted of three coal fired stoker boilers that were shut down and replaced with an atmospheric circulating fluidized bed (CFB) boiler (Unit #4). Unit #4 was placed in service in June, 1987. CFBs without post-combustion controls are able to achieve emission rates of NO_x and SO_2 that are lower than Pulverized Coal (PC) fired boilers due to the nature of their design (lower combustion temperatures result in less NO_x formation, while intimate mixing of a sorbent within the fluidized bed results in enhanced SO_2 removal). SO_2 emissions from CFBs without post-combustion controls are typically lower than similarly sized PC-fired boilers equipped with Flue Gas Desulfurization (FGD) systems.[2] The original construction of Unit #4 included four baghouses for the control of PM_{10} emissions, limestone injection to the combustion chamber for SO_2 removal, and inherent minimization of NO_x emissions due to boiler design.

In 2006, Tri-State permitted and installed a small-scale SNCR system that injects anhydrous ammonia to provide additional NO_x reduction. Tri-State does not operate the SNCR system frequently; it is used on occasions when NO_x emissions approach 0.4 lb/MMBtu (operation above this level at high unit capacity factors results in levels that approach the annual NO_x limit of 1,987.9 tons per year on a 12-month rolling basis). The system was designed with a 2,000 gallon tank and a flow rate during operation of around 10 gallons per hour.[3]

Nucla Unit 4 is considered by the Division to be eligible for the purposes of Reasonable Progress, being an industrial boiler with the potential to emit 40 tons or more of haze forming pollution (NO_x, SO_2, PM_{10}) at a facility with a Q/d impact greater than 20. Tri-State Generation and Transmission Association (Tri-State) provided information relevant to RP to the Division on December 31, 2009, May 14, 2010, and July 30, 2010. Table 1 depicts technical information for Unit 4 at Nucla Station.

Table 1: Nucla Unit 4 Technical Information

	Unit 4
Placed in Service	1987
Gross Boiler Rating, MMBtu/Hr for coal	1,112
Electrical Power Rating, Net Megawatts	110
Description	Pyropower Circulating Fluidized Bed, Coal Fired Boiler

[2] Babcock & Wilcox Company, 2000. "Why Build a Circulating Fluidized Bed Boiler to Generate Steam and Electric Power" Presented to POWER-GEN Asia 2000. Page 2.
[3] Tri-State, May 14, 2010. "RE: Response to the Division's January 25, 2010 Letter Regarding NO_x Emissions Control Costs." Page 6.

Air Pollution Control Equipment	PM/PM_{10} –Fabric Filter Baghouses (1987) NO_x – Voluntary SNCR (2006) SO_2 – Limestone Injection (1987)
Emissions Reduction (%)	NOx – NA[4] SO_2 – 77.4% PM/PM_{10} – 98% - 99.9+%[5]

II. Source Emissions

Table 2 summarizes the NO_x and SO_2 actual emissions averaged over the 2006 – 2008 timeframe from EPA's CAMD Database for the facility. Table 3 summarizes each unit at the facility and applicable NO_x, SO_2, and PM_{10} actual emissions averaged over the 2006 – 2008 timeframe with data from Colorado's Air Pollutant Emission Notices (APENs) submitted by the facility (based on amount and heat content and amount of coal combusted, also as reported on the APENs).

Table 2. Summary of 2006 - 2008 Averaged Emissions – Tri-State Nucla Station

NO_x (tons/year)	SO_2 (tons/year)	PM_{10} (tons/year)
1,760	1,335	40

Table 3. Summary of 2006 - 2008 Averaged Emissions by Unit – Tri-State Nucla Station

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
Unit 4 Boiler	SO_2 (tons)	1509.4	1230.4	1265.7	1335.2
	SO_2 (lb/MMBtu)	0.34	0.30	0.30	0.31
	NO_x (tons)	1716.0	1598.0	1711.4	1675.1
	NO_x (lb/MMBtu)	0.39	0.38	0.40	0.39
	PM_{10} (tons)	41.6	39.4	40.24	40.4
	PM_{10} (lb/ MMBtu)	0.009	0.009	0.009	0.009
Coal Handling & Processing	*PM_{10} (tons)*	*2.09*	*2.15*	*2.15*	*2.13*
Ash Handling & Processing	*PM_{10} (tons)*	*8.91*	*10.62*	*10.62*	*10.05*
P401 Cooling Tower	PM_{10} (tons)	37.5	23.7	0.34	20.5
P402 Cooling Tower	*PM_{10} (tons)*	*9.8*	*9.8*	*9.8*	*9.8*
Limestone Preparation	*PM_{10} (tons)*	*1.29*	*1.29*	*1.29*	*1.29*

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average.

Units *italicized* in Table 3 are less than *de minimis* thresholds and will not be evaluated further for the purposes of reasonable progress.

[4] NO_x emission reductions from the existing SNCR system have not been characterized because the system is operated only infrequently – total reported emissions are therefore assumed to be uncontrolled.

[5] The low range is calculated assuming uncontrolled emissions based on AP-42 factors. The high range is stated in the U.S. Department of Energy: Project Fact Sheet – Nucla CFB Demonstration Project. http://www.netl.doe.gov/technologies/coalpower/cctc/cctdp/project_briefs/nucla/documents/nucla.pdf. Page 5.

Note also that Tri-State installed improved drift eliminators on the P401 Cooling Tower in 2007. The Operating Permit[6] for the facility includes a limit of 0.55 tons PM_{10} per year effective beginning October 1, 2007 (actual emissions for 2008 were reported to be 0.34 tons per year); therefore this unit will also not be considered further in this analysis.

The Title V permit includes the following limits for the Unit 4 Boiler:

- NO_x: 0.50 lbs/MMBtu on a rolling 30-day average (PSD limit), 0.5 lb/MMBtu on a rolling 30-day average (NSPS Subpart Da) and 1987.9 tons per year on a rolling 12-month total
- SO_2: 1.2 lb/MMBtu on a rolling 30-day average (NSPS Subpart Da), 1.2 lb/MMBtu on a 3-hr average (Colorado Regulation No. 1), 0.4 lb/MMBtu on a 30-day average (Colorado Regulation No. 6) and 1598.9 tons per year on a rolling 12-month total; 70% reduction at less than 0.6 lb/MMBtu (30-day rolling average)
- PM_{10}: 131 tons per year on a rolling 12-month total
- PM: 0.03 lb/MMBtu (PSD limit), 0.03 lb/MMBtu (NSPS Subpart Da) 0.1 lb/MMBtu (Colorado Regulation No. 1) and 135.9 tons per year on a rolling 12-month total

III. Units Evaluated for Control

The Nucla boiler burns Colorado bituminous coal. Nucla Station is a mine-mouth facility; therefore the Division assumes that this facility burns New Horizon Coal, since that facility is the closest coal mine identifiable in Division records. The actual APEN coal specifications (2006 – 2008) are listed below in Table 4. Uncontrolled emission factors are outlined in Table 5.

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

	Specifications		
Emission Unit	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Nucla Unit 4	10,545	0.83	19.95

Table 5: Uncontrolled emission factors for Nucla RP-eligible sources[7]

	Pollutant			
Emission Unit	NO_x	SO_2	PM (filterable)	PM_{10} (filterable)
Unit 4 (lb/ton)	5.0	25.8	17.0	12.4
Unit 4 (lb/MMBtu)	0.24	1.22	0.81	0.59

[6] Colorado Air Pollution Control Division, September 25, 2007. Colorado Operating Permit 96OPMO168: Nucla Station. Section II: Condition 8.2, Page 38.

[7] PM and PM_{10} emission factors are from 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 (for spreader stokers with multiple cyclones and reinjection). Uncontrolled SO_2 emission factors are based on the AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.1 emission factor for underfeed stoker boilers (Table 1.1-3). Uncontrolled NO_x emission factors are based on actual emissions from 2006 – 2008.

IV. Reasonable Progress Evaluation of Unit 4

a. Sulfur Dioxide

Step 1: Identify All Available Technologies

The Division identified all of the available CFB control technologies listed below.

Fuel Switching – Natural Gas or Alternate Coal Source
Fuel Washing
Limestone Injection Process Upgrades
Post-Combustion Controls: Dry Scrubbing (Spray Dry Absorber, Circulating Dry Scrubber, Hydrated Ash Reinjection and Dry Sorbent Injection)
Post-Combustion Controls: Wet Scrubbing

As discussed in EPA's BART Guidelines[8], electric generating units (EGUs) with existing controls achieving removal efficiencies of greater than 50 percent are not required to remove these controls and replace them with new controls. However, upgrades need to be considered for the existing limestone injection process if technically feasible.

The current PSD permit SO_2 limits are depicted in Table 6.

Table 6: Nucla Unit 4 SO_2 PSD Permit Limits

	SO_2 limits (lb/MMBtu)			Rolling 12-month Emission Limit (tons/year)
	3-hour avg. (Colo. Reg. No. 1)	Rolling 30-day avg. (NSPS Subpart Da)	30-day avg. (Colo. Reg. No. 6)	
Unit 4	1.2	1.2	0.4	1,599

Step 2: Eliminate Technically Infeasible Options

Fuel Switching – Natural Gas or Alternative Coal Sources: CFB boilers are designed to create a circulating bed of solid fuels; the nature and locations of the solids and air injection points as well as the combustion zone itself are inherently different from traditional PC and natural gas-fired boilers. The recent conversion from a natural gas-fired boiler to a CFB-boiler at the Lamar Light and Power facility in Lamar, Colorado required the construction of an entirely new and separate unit. Therefore, the Division determines that the conversion to natural gas is technically infeasible for Nucla's CFB boiler.

Nucla Unit #4 is currently burning coal from the New Horizon Mine located five miles south of the plant, with an average sulfur content of 0.83%. The facility is located approximately 4.5 miles southeast of Nucla, Colorado and does not have rail service. There are no other coal mines located 100 miles of the facility. Because the current coal source is already lower than 1% sulfur and no other sources within a reasonable distance of the facility have been identified, fuel switching to other coal types will not be considered further in this analysis.

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

Fuel Washing: Fuel washing has been used historically to reduce the sulfur content of some high sulfur coals prior to combustion. There are no identified fuel-washing processes for low sulfur coal.

Existing Process Upgrades and Post-Combustion Controls: In the absence of any specific feasibility or cost information related to SO_2 controls for the Nucla Station, the Division relied on control evaluations performed for other CFB boilers, with a focus on CFB boilers in the western part of the country. Coal supplies for CFB boilers in the eastern part of the country are significantly different from western coals in terms of sulfur and heat content; therefore the Division believes that the specifics of control devices for eastern CFB boilers may not be wholly applicable to Nucla Unit 4. The majority of recent BACT determinations identify limestone injection, with or without additional post-combustion controls as the chosen SO_2 control device. Refer to "Division RBLC Analysis" for more details. The Division reviewed two of the most recent BACT analysis reports in detail: the lignite-fired Spiritwood Station in North Dakota[9] and the waste coal-fired Bonanza Station in Utah[10]. The Spiritwood Station was intended to fire beneficiated lignite but is designed with the capability for firing dried lignite and subbituminous coal as well, and the BACT analysis specifically identified the findings to be applicable to subbituminous coal. The estimated control efficiencies and costs from these reports were used as a basis to evaluate potential SO_2 emission control options at Nucla.

Limestone Injection Process Upgrades: The average reduction in SO_2 emissions due to limestone injection into the CFB boiler for the baseline period is estimated to be 77.4% as shown in Table 1, above. The unit participated in a U.S. Department of Energy Clean Coal Technology Demonstration Program (CCTDP) from 1988 – 1991 in order to examine the energy and environmental impacts from the unit, which was the first utility-scale atmospheric CFB boiler at the time. The project demonstrated a 70% SO_2 removal rate at a calcium to sulfur ratio (Ca/S) of 1.5 and a 95% removal rate at a calcium to sulfur ratio of 4.0[11]. The demonstration project tested a range of western bituminous coals, including Salt Creek (0.5% sulfur), Peabody (0.7% sulfur) and Dorchester (1.5% Sulfur), with the Salt Creek coal serving as the baseline coal (used in 62 of the 72 tests). Limestone injection process upgrades are feasible for Nucla Unit 4.

Post-Combustion Controls – Dry Scrubbing: Additional treatment of the boiler exhaust gases can potentially be accomplished with several dry scrubbing techniques.

[9] Barr, July 2007. "Application for a Permit to Construct a Combined Heat and Power (CHP) Plant." Prepared for Great River Energy – Spiritwood Station, Spiritwood, ND.
[10] EPA, August 30, 2007. "Deseret Power Electric Cooperative, Bonanza Power Plant, Waste Coal Fired Unit: Prevention of Significant Deterioration Permit to Construct – Final Statement of Basis for Permit No. PSD-00-0002.01.00. "
[11] U.S. Department of Energy: Project Fact Sheet – Nucla CFB Demonstration Project. http://www.netl.doe.gov/technologies/coalpower/cctc/cctdp/project_briefs/nucla/documents/nucla.pdf

Spray Dryer Absorption (SDA) is the most commonly used follow-on controls for CFB boilers with limestone injection. SDAs currently make up about 12% of Flue Gas Desulfurization (FGD) systems at U.S. power plants[12]. SDA systems are typically utilized at smaller units that burn lower-sulfur coal in the western U.S., where water resources are limited. A SDA system captures SO_2 by using slaked lime slurry that is sprayed into the flue gas, subsequently dried by the heat of the flue gas, and the collected in a particulate control device. A SDA system is technically feasible for Nucla Unit 4.

Circulating Dry Scrubber (CDS) Systems use a circulating fluidized bed of dry hydrated lime in a separate reactor tower. The flue gas must first be humidified with a water mist. EPA noted in the Bonanza BACT analysis that CDS systems have limited application on large PC-fired boilers or CFB boilers, and can result in particulate loading rates that are high enough to create unacceptable pressure drops across fabric filters and therefore require electrostatic precipitators for particulate control.[13] The potential need to replace the existing baghouse (99.9% particulate control) with an electrostatic precipitator renders a CDS system inappropriate as an option for the Nucla station.

Hydrated Ash Reinjection (HAR) increases utilization of uncreated calcium oxide in the CFB boiler ash by collecting, hydrating and re-introducing a portion of the unit's ash in a separate vessel prior to the baghouse. HAR is technically feasible for Nucla Unit 4.

Dry Sorbent Injection (DSI) systems require injection of powdered absorbent directly into the flue gas stream. EPA identified this option as impractical for use in a CFB boiler burning low sulfur coals due to an expected SO_2 reduction of less than 50%.[14] DSI is a technically feasible option for Nucla.

Post-Combustion Controls – Wet Scrubbing: Wet Flue Gas Desulfurization (FGD) systems were identified as potentially feasible for CFB boilers in both the Bonanza and Spiritwood BACT analyses. The process involves an alkaline slurry (lime or limestone) scrubbing liquid in an absorber tower. The process produces a wet byproduct that requires dewatering. Wet scrubbing is a technically feasible option for Nucla Unit 4.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Limestone Injection Process Upgrades: The Spiritwood BACT analysis states that the control efficiency from the limestone injection process is expected to be 75%[15] (further reductions occur in a Spray Dry Absorber). EPA acknowledges in the Bonanza BACT analysis report that a control efficiency of 80 – 85% should be expected for the limestone injection process alone[16].

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[12] Recommendations, Technical Report, September 2007. University of North Dakota: Energy & Environment Research Center – Coal Ash Resources Research Consortium. 15 North 23rd Street, Stop 9018. Grand Forks, ND, 58202. Pg V.
[13] Ibid., Page 92.
[14] EPA, Deseret Power Electric Cooperative…Page 93.
[15] Barr, Appendix E, Page 50
[16] EPA, Deseret Power Electric Cooperative…Page 99.

The Division believes that an expectation of 95% reduction for the Nucla station from the limestone injection process, although it may have been demonstrated during the CCTDP test project, is not appropriate as a long term operation scenario. The fluidized bed is currently optimized carefully to balance efficiency, operational and emission characteristics. Increasing the Ca/S to 4.0 in order to achieve 95% SO_2 reduction is expected to cause significant operational issues; the Division has not found any evidence of current CFB boilers in operation with Ca/S ratios near 4.0. Higher limestone injections will also result in an increase in NO_x emissions, although the quantitative relationship is not well understood.[17] For these reasons, the Division believes that an increase in SO_2 control efficiency to 85% by increasing limestone injection is a feasible option. This correlates to an approximate 39.4% decrease in comparison to current SO_2 emissions.

Spray Dry Absorber: Based on experience with other Colorado EGUs, the Division believes that a realistic achievable control efficiency for a SDA at Nucla is approximately 87%, or an approximate 0.04 lb/MMBtu (30-day rolling average). This is approximately 97% from uncontrolled SO_2 emissions. A review of the EPA's RBLC database showed two retrofit Western facilities from about 0.04 – 0.05 lb/MMBtu (30-day rolling average) with SDAs as the SO_2 control option. Please refer to the document "RBLC for CFBs – July 2010" for more information.

Limestone Injection Improvements + Spray Dry Absorber: Limestone injection improvements (85%) combined with a spray dry absorber (90%) could achieve up to approximately 94% control from current SO_2 emissions, or 98.4% from uncontrolled SO_2 emissions.

Hydrated Ash Reinjection: EPA references vendor information showing that hydrated ash reinjection could reduce the post-combustion SO_2 emissions by about 80%.[18] This results in about 95% reduction from uncontrolled SO_2 emissions.

Hydrated Ash Reinjection + Limestone Injection Improvements: It may be possible to combine HAR (80% reduction) with improvements to the limestone injection system (85% reduction). This results in a potential 87.9% decrease from current SO_2 emissions or 96.9% reduction from uncontrolled SO_2 emissions.

Post-Combustion Controls – Wet Scrubbing: EPA noted a potential SO_2 removal efficiency of 94% for the post-combustion gas in the Bonanza BACT analysis[19]. Combined with the current limestone injection system, the overall potential control efficiency is 98.4% from uncontrolled SO_2 emissions.

[17] Ibid., Page 100.
[18] Barr, Appendix E, Page 93.
[19] Ibid., Page 94.

Table 7 summarizes each available technology option and technical feasibility for SO_2 control for Nucla Unit 4.

Table 7: Nucla Unit 4 SO2 Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Fuel switching – Natural gas or alternate coal source	Natural gas: 99% Alternate coal: minimal	Natural gas – N Alternate coal – Y – will not provide further SO2 control
Fuel washing	Minimal	N
Limestone Injection Process Upgrades	~85% overall control efficiency ~40% increase from current control efficiency	Y
Dry Scrubbing (SDA)	~97% overall control efficiency ~87% increase from current control efficiency	Y
Limestone Injection Improvements + SDA	~98% overall control efficiency ~94% increase from current control efficiency	Y
Circulating Dry Scrubber	Unknown	N
Hydrated Ash Reinjection (HAR)	~95% overall control efficiency ~80% increase from current control efficiency	Y
HAR + Limestone Injection Improvements	~97% overall control efficiency ~88% increase from current control efficiency	Y
Dry Sorbent Injection (DSI)	<50% overall control efficiency	Y – will not provide further SO2 control
Wet Scrubbing	~98% overall control efficiency ~94% increase from current control efficiency	Y

Step 4: Evaluate Factors and Present Determination

Factor 1: Cost of Compliance

Costs for SO_2 control options were evaluated based on analyses for similar systems proposed at other western CFB boiler units (Spiritwood and Bonanza). Refer to “Nucla APCD Cost Analysis” for more details. Depending on the control option, the Division also relied on additional submittals regarding Nucla feasibility and costs submitted on

Limestone Injection Process Upgrades: The Division relied on the U.S. Department of Energy Clean Coal Technology Demonstration Program (CCTDP) study to determine control efficiency for limestone injection upgrades. The Spiritwood BACT analysis used the cost of limestone in 2006 to determine limestone injection costs. The Division adjusted this cost using the Consumer Price Index (CPI), increasing limestone cost from \$80 per ton to \$87 per ton. The Division also calculated the additional amount of limestone (in tons per year) that will be needed to achieve an 85% control efficiency (or 40% increase from current control efficiency). These calculations result in an annualized cost of \$914,920 per year. Refer to "Nucla APCD Cost Analysis" for more details.

Dry Scrubbing (Spray Dry Absorber)/ Limestone Injection Process Upgrades + SDA: The Division again relied on the Spiritwood BACT Analysis to determine the cost of a spray dry absorber (SDA) system. The annualized cost (2006) for the Spiritwood CFB was \$2,644,412. The Division used the CPI to adjust this cost to \$2,814,108 and then scaled this cost up by the ratio of potential tons SO_2 removed at the Nucla CFB compared to tons removed at the Spiritwood CFB, and then added in a retrofit factor of 50% to consider the difficulty of the retrofit at Nucla as compared to a new CFB (Spiritwood). This results in an annualized cost of \$4,304,807. For limestone injection improvements combined with a SDA system, the Division combined annualized costs from both controls to result in an annualized cost of \$5,219,097. Refer to "Nucla APCD Cost Analysis" for more details.

Wet Scrubbing: Although Wet FGD systems provide higher levels of SO_2 removal over dry scrubbers, their incremental cost is likely the reason that they are not identified as BACT controls on any CFB boilers. The incremental cost of using a wet scrubber versus the spray dry absorber is identified as \$12,902/ton in the Spiritwood BACT analysis[20], and \$10,540 per ton in the Bonanza BACT analysis.[21] A wet scrubber at the Nucla Station should be expected to have even higher costs than these examples due to the retrofit factor. Therefore, a Wet FGD option will not be considered further in this analysis.

HAR/HAR+Limestone Injection Improvements: Study-level information for potential HAR systems at Nucla or any other EGU in the western part of the country were not available for use in evaluating costs. Therefore, the Division does not consider this option to commercially available at this time, and HAR will not be considered further in this analysis. However, HAR is technically feasible and will be considered in future analyses if more information becomes available.

Table 8 illustrates resultant SO_2 emissions for each technically feasible control option. Table 9 shows the SO_2 control cost comparisons for each unit based on the detailed cost analyses. The Division used baseline emissions from Table 3. 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.

[20] Barr, Appendix E, Page 95.
[21] EPA, Deseret Power Electric Cooperative…Page 95.

Table 8: Nucla Unit 4 Control Resultant SO_2 Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Unit 4		
		(tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,335	0.299	0.314
Limestone Injection Improvements (LII)	39.4	809	0.182	0.191
Hydrated Ash Reinjection (HAR)	80.0	267	0.060	0.063
Spray Dry Absorber (SDA)	87.0	174	0.039	0.041
HAR + LII	87.9	162	0.036	0.038
LII+SDA	93.9	81	0.018	0.019
Wet Scrubbing	94.0	80	0.018	0.019

Table 9: Nucla Unit 4 SO_2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
LII	526	$2,188,595	$4,161	$4,161
HAR	1,068	Not determined		
HAR+LII	1,173	Not determined		
SDA	1,162	$7,604,627	$6,547	$8,520
LII+SDA	1,254	$9,793,222	$7,808	$23,619
Wet Scrubbing	1,255	Not determined		

Factor 2: Time Necessary for Compliance

It is assumed that the Limestone Injection Improvements will not require any construction or capital improvements since the Unit has already been demonstrated at the higher Ca/S ratios during the CCTDP test project.

Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take Tri-State approximately 3 – 5 years to implement the SDA or LII+SDA control options. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

There are no identified energy or non-air quality impacts associated with improvements to the Limestone Injection System. Thus, this factor does not influence the selection of this control.

Wet Scrubbing: 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.

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. 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 Regional Haze program. The Division largely focused its RP 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 the negative environmental impacts of a traditional wet FGD control system far outweigh minimal incremental SO_2 emission reduction benefits (tons of SO_2 reduced annually) and visibility improvement (deciview improvement at nearest Class I area) when compared to a SDA system when applied to the Nucla Unit 4 CFB boiler.

Spray dry absorber (SDA): Other Colorado facility have noted 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. There will be a greater volume of material being landfilled. A LSD scrubber consumes a tremendous amount of water. Wet scrubbers consume approximately 23% more water than LSD scrubbers, depending on boiler size.[22]

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: Other Colorado facility have documented 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,[23] 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

Factor 4: Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of this boiler, 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.

[22] 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.

[23] 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

Factor 5 (optional): Evaluate Visibility Results
Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis.

Step 6: Select RP Determination

Nucla already has a system in place to inject limestone into the boiler as required by current state and federal air permits. This system achieves an approximate 70% SO2 emissions reduction capture efficiency at a permitted emission rate of 0.4 lbs/MMBtu limit. Increased SO2 capture efficiency (85%) with the existing limestone injection as an effective system upgrade, by use of more limestone (termed "limestone injection improvements") was evaluated and determined to not be feasible under certain operating conditions. The system cannot be 'run harder' with more limestone to achieve a more stringent SO2 emission limit; the system would have to be reconstructed or redesigned with attendant issues, or possibly require a new or different SO2 system, to meet an 85% capture efficiency.

Based upon its consideration of the five factors summarized herein, the state has determined that the existing permitted SO_2 emission rate for Unit 4 satisfies RP:

Nucla Unit 4: 0.4 lb/MMBtu (30-day rolling average)

The state assumes that the emission limit can be achieved through the operation of the existing limestone injection system.

b. Filterable Particulate Matter (PM) & Particulate Matter (PM_{10})

Nucla Unit 4 is currently equipped with a four baghouse system to control PM/PM_{10} emissions from the boiler. 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 micron in diameter. Additionally, fabric filters are the best PM control for western coals, due to the higher electrical resistivity.

The baghouses performed over the 2006 – 2008 baseline period with PM and PM_{10} emissions of 0.013 lb/MMBtu and 0.009 lb/MMBtu, respectively. During the CCTDP test project, the unit demonstrated particulate emissions ranging between 0.0072 to 0.0125 lb/MMBtu, corresponding to a removal efficiency of 99.9%[24]. This boiler is subject to 40 CFR Part 60, Subpart Da, which requires 99% reduction (for facilities commencing construction after September 18, 1978) of the potential combustion concentration when burning solid fuel.

[24] U.S. Department of Energy, Page 5.

A Division review of the PM/PM_{10} emission limits in the current Title V permit revealed that these limits are for filterable PM/PM_{10} emissions only.

Table 10 shows the most recent *verified* stack test data (2002). Another stack test was conducted in August 2010, but is not yet available for release due to ongoing analysis by the Division and Tri-State. Real-time data demonstrates that these baghouses are meeting >95% control. The Operating Permit (96OPMO168) limit is 0.03 lb/MMBtu for PM/PM_{10} emissions (Conditions 1.1.1, 1.1.2). 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 10: Nucla Unit 4 Stack Test Results (August 2002)

Pollutant	Unit 4 (lb/MMBtu)
Filterable PM_{10}	0.014
PM_{10} Control efficiency	98.3%

A Division review of EPA's RBLC revealed recent BACT PM/PM_{10} determinations range from 0.010 – 0.10 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 limit of 0.03 lb/MMBtu is in the range of recent BACT determinations. Please refer to "Division RBLC Analysis" for more details about recent BACT determinations.

The State has determined that the existing regulatory emissions limit of 0.03 lb/MMBtu represents the most stringent control option. The unit is exceeding a PM control efficiency of 95%, and the control technology and emission limit is RP for PM/PM_{10}. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouse. Therefore, a full 4-factor analysis is not needed to evaluate PM/PM_{10} for the Unit 4 boiler.

c. *Nitrogen Oxides (NO_x)*

Step 1: Identify All Available Technologies

Fuel Switching – Natural Gas or Alternate Coal Source
Selective Non-Catalytic Reduction (SNCR) system upgrades
Selective Catalytic Reduction (SCR) with flue gas reheat

Step 2: Eliminate Technically Infeasible Options

Tri-State provided an analysis of the requirements and costs associated with increasing the size of the existing SNCR system to allow for more frequent operation, and the Division has relied on this information (with some exceptions) in order to evaluate a full-time SNCR option. Due to lack of any specific feasibility or cost information related to SCR controls at Nucla Station, the Division relied on recent control evaluations performed for other CFB boilers in the western part of the country (the Spiritwood and Bonanza evaluations, noted in Section III.a. above).

Every BACT determination listed in the RACT/BACT/LAER Clearinghouse for CFB Boilers specifies SNCR; no SCR determinations or installations have been identified. This is likely due to the significantly high incremental costs of SCR systems, as discussed below.

As described above for SO_2 controls, fuel switching to natural gas or an alternative coal source is not considered technically feasible.

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. SNCR is considered a technically feasible alternative is Nucla Unit 4.

SCR: SCR systems are the most widely used post-combustion NO_x control technology for PC-fired boilers. SCR control involves injecting ammonia into the flue gas stream in the presence of a catalyst, and requires a temperature range of 500°F – 800°F. SCR systems are not considered feasible for CFB boilers because the particles present in the boiler exhaust act as catalyst poisons. However, the recent BACT analyses for the Spiritwood and Bonanza Units have considered the application of SCR technology following the particulate control device on CFB boilers in order to achieve 90% NO_x reduction. Since baghouse exhaust temperatures are too low to satisfy SCR requirements, reheating of the flue gas is required. NO_x control efficiencies of 90% are expected. The Division considers SCR a technically feasible alternative for Nucla Unit 4. Please see the cost section for more details regarding SCR.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

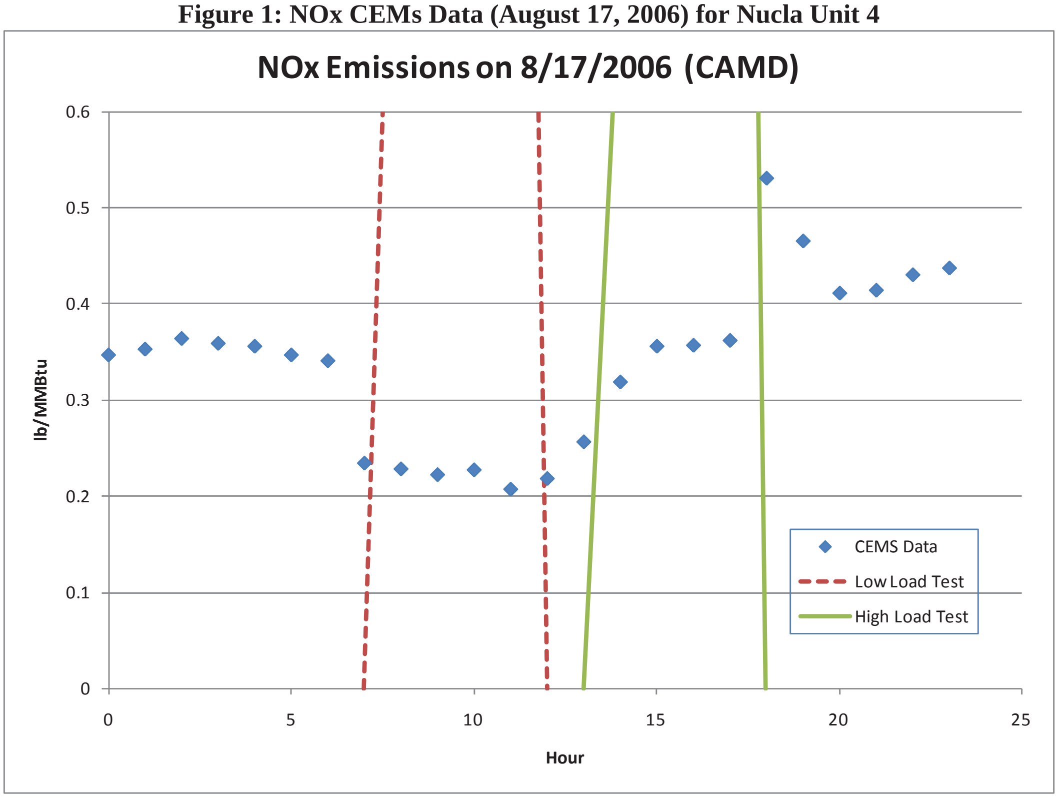
SNCR: The current SNCR system associated with Unit 4 is a small system using anhydrous ammonia injection for NO_x trim during period when emissions approach 0.4 lb/MMBtu (the permit limit is 0.5 lb/MMBtu). NO_x trim is required to ensure that the facility is able to meet the 1,987.9 ton per year permit limit on a rolling 12-month total. Tri-State notes that the unit is not in service the majority of the time. The system was designed with a 2,000 gallon tank and a flow rate during operation of around 10 gallons per hour, allowing only 8 days of continuous service. Tri-State also notes that there is such a wide variability in the effectiveness of SNCR for controlling NO_x emissions that only 10% control should be assumed, but provided no data to support this value. Note that 10% control over a baseline of 0.39 lb/MMBtu is 0.35 lb/MMBtu.

On August 17, 2006, Tri-State performed a stack test in order to ensure that ammonia slip emissions resulting from the newly installed SNCR system would not result in a significant emission increase (for PM_{10}) and trigger PSD review for the project. The test was completed at maximum and minimum boiler loads, and maximum ammonia injection rate (15.4 – 15.5 gallons per hour)[25]. The test runs occurred during the following timeframes:

Low Load (80.4 MW)	High Load (109.2 MW)
Run 1: 7:28 – 8:28	Run 1: 13:51 – 14:51
Run 2: 9:14 – 10:14	Run 2: 15:25 – 16:25
Run 3: 10:44 – 11:44	Run 3: 16:52 – 17:52

The NO_x CEMS data from CAMD for August 17, 2006 in Figure 1 shows an hourly NO_x rate during the low load test of 0.22 lb/MMBtu (corresponding to 43.6% control over the baseline), and an hourly NO_x rate during the high load test of 0.35 lb/MMBtu (corresponding to 10.3% control).

Figure 1: NOx CEMs Data (August 17, 2006) for Nucla Unit 4



The low load rate of control is more in line with estimates for the SNCR systems in the Spiritwood and Bonanza BACT analyses (58%[26] and 47%[27], respectively).

[25] Colorado Department of Public Health & Environment, November 2, 2006. "Stack Testing Report, Nucla Station"
[26] Barr, Appendix E, Page 56.
[27] EPA, Deseret Power Electric Cooperative…Page 49.

The Division conducted an analysis to determine the typical load for Nucla Unit 4 using baseline data (2006 – 2008). From 2006 – 2008, Nucla ran at 97.6% load. This high load data indicates that 10.3% control is more reasonable. However, the Division and Tri-State both note that the existing small scale SNCR system is not designed for full-scale operation and would last about 8 days in continuous service and has never operated for an extended period of time. Tri-State further notes that given the design purpose of the existing system for injection to trim emissions as needed, the system is not engineered to achieve a specific percent reduction. The Division concludes that there is a significant amount of uncertainty surrounding the application of SNCR on CFB boilers due to lack of information at this time.

Table 11 summarizes each available technology and technical feasibility for NO_x control.

Table 11: Nucla Unit 4 NO_x Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Fuel switching – Natural gas or alternate coal source	Natural gas: 20 – 70% Alternate coal: minimal	Natural gas – N Alternate coal – Y – will not provide further NOx control
Low NO_x Burners (LNB)	~10%	N – CFB boiler
Overfire air (OFA)	10 – 25% (alone)	N – CFB boiler
Selective non-catalytic reduction (SNCR)	20 – 40%	Y – small scale system already installed
Selective catalytic reduction (SCR)	70 – 90%	Y

Step 4: Evaluate Factors and Present Determination

Tri-State provided the Division annual average control estimates. In the Division's experience and other state BART proposals,[28] 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 Nucla Unit 4 to determine control efficiencies and annual reductions.

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

Factor 1: Cost of Compliance

SCR: Although SCR systems provide significantly higher levels of NO_x removal over SNCR systems, their incremental cost is likely the reason that they are not identified as BACT controls on any CFB boilers. The incremental cost of using SCR versus SNCR on a CFB Boiler is identified as $25,315/ton in the Spiritwood BACT analysis[29], and $40,297 per ton in the Bonanza BACT analysis[30]. A SCR system at the Nucla Station should be expected to have even higher costs than these examples due to a retrofit factor and small size. Therefore, the Division considers that costs for SCR will be excessive. Additionally, site-specific costs for SCR on Nucla are not available at this time.

SNCR: The cost associated with installation of an upgraded SNCR system is shown below. Costs are based on values submitted by Tri-State on May 14, 2010.[31] Refer to "Nucla APCD Cost Analysis" for more details. The Division used two discrete control efficiencies to demonstrate the significant uncertainty of the application of SNCR and the variation in resultant cost effectiveness.

Table 12 and Table 13 depict controlled NO_x emissions and control cost comparisons.

Table 12: Nucla Unit 4 Control Resultant NO_x Emissions

Alternative	Control Efficiency (%)	Resultant Emissions		
		Annual Emissions (tons/year)	Annual Average (lb/MMBtu)	30-day Rolling Average (lb/MMBtu)
Baseline	---	1,675	0.387	
SNCR	10.3	1,503	0.347	0.399
SNCR	43.6	945	0.218	0.251

Table 13: Nucla Unit 4 NO_x Cost Comparisons

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---
SNCR	173	$2,238,592	$12,974	$12,974
SNCR	730	$2,238,592	$3,065	---

[29] Barr, Appendix E, Page 57.
[30] EPA, Deseret Power Electric Cooperative…Page 51.
[31] Tri-State, Page 3.

Factor 2: Time Necessary for Compliance

Tri-State states that the SNCR project could be implemented in a two to three year time frame, but also notes that[32]:

> "Projects of this size entailing a significant outage lasting eight weeks or more must be integrated into the long term schedule in order to coordinate with the management of the grid and for power replacement commitments. The date on which EPA SIP approval occurs is necessarily the starting point for any schedule including significant investments for engineering and design, procurement of equipment and contract commitments. In addition, the schedule would have to be integrated into the electric supply planning process."

Tri-State has also described significant constructability challenges and balance-of-plant changes that will likely affect the timeframe for reconstruction of the SNCR project[33]. Nucla station is located approximately 70 miles from the nearest interstate highway. The facility does not have rail service and is located 40 miles from the nearest commercial air terminal. Below freezing temperatures are expected seven months of the year, which affects soil excavation, structure foundations and concrete placement.

Based on other Colorado facility submittals, the Division anticipates that the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval, it would take Tri-State approximately 3 - 5 years to implement any of the above control options. This timeframe may vary somewhat due to regional demand for natural gas and to schedule the necessary major maintenance outage with other regionally affected utilities.

Factor 3: Energy and Non-Air Quality Impacts

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. The cost associated with increased power needs was addressed in the cost effectiveness study provided by Tri-State and is reflected in the costs shown in the tables above.

Installing SNCR 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.

[32] Ibid., Page 24.
[33] Ibid., Page 10.

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; Tri-State has indicated that the larger quantity of on-site anhydrous ammonia storage required by the scale-up of the SNCR system will require the review and approval of new Risk Management Plans and Process Safety Management Plans. The larger tank may also trigger other state and local ordinances and requirements.

Factor 4: Remaining Useful Life

Tri-State asserts that there are no near-term limitations on the useful of this boiler, 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.

Factor 5 (optional): Evaluate Visibility Results

Due to time and domain constraints, projected visibility improvements were not modeled by the state for this analysis. Nucla has a limited, small-scale SNCR system for emissions trimming purposes already installed.

Step 6: Select RP Determination

Based upon its consideration of the five factors summarized herein, the State has determined that NOx RP for Nucla Unit 4 is the following NOx emission rate:

Nucla Unit 4: 0.5 lb/MMBtu (30-day rolling average)

Additional Analyses of SO2 and NOx Controls for Nucla

As state-only requirements of this Reasonable Progress determination, the Commission requires, and Tri-State agrees, that Tri-State conduct a comprehensive four factor analysis of all SO2 control options for Nucla using site-specific studies and cost information and provide to the state a draft analysis by July 1, 2012. A protocol for the four-factor analysis and studies will be approved by the Division in advance. The analysis will include enhancements or upgrades to the existing limestone injection system for increased SO2 reduction performance, and other relevant technologies such as lime spray dryers and flue gas desulfurization. A final analysis that addresses the state's comments shall be submitted to the state by January 1, 2013. By January 1, 2013, Tri-State shall also conduct appropriate cost analyses, study and testing, as approved by the Division, to inform what performance would be achieved by a full-scale SNCR system at Nucla to determine potential circulating fluidized bed (CFB) boiler-specific NOx control efficiencies. By January 1, 2013, Tri-State shall conduct CALPUFF modeling in compliance with the Division's approved BART-modeling protocol to determine potential visibility impacts the different SO2 and NOx control scenarios for Nucla.

Finally, Tri-State shall propose to the state any preferred SO2 and NOx emission control strategies for Nucla by January 1, 2013. On December 26, 2012, Tri-State submitted an updated four-factor analysis and visibility modeling to the Division, with the conclusion that limestone for SO2 control and existing SNCR for NOx reduction remained the preferred strategy.

Requirements for Nucla Station

On December 31, 2012, EPA approved Colorado's Regional Haze SIP, including Colorado's Reasonable Progress determination for Nucla Unit 4 (0.5 lb/MMBtu (30-day rolling average)). In 2016, based on new information provided from an agreement amongst Tri-State, WildEarth Guardians, the National Parks Conservation Association, EPA, and the state, the state conducted a Reasonable Progress review of Nucla. This review adds a requirement of a closure date on or before December 31, 2022 for Nucla Station. Additionally, an annual NO_x limit of 952 tons per year will be effective January 1, 2020 on a calendar year basis beginning in 2020.

These requirements are the result of an agreement. The 2022 closure achieves further NOx reductions and other environmental co-benefits than the 2011 RP determination. Consistent with the agreement and in lieu of being subject to stringent requirements as part of the long term strategy for the second implementation period of Regional Haze, Nucla Station will close by December 31, 2022. Additionally, an annual NOx limit of 952 tons per year will be effective on January 1, 2020 on a calendar year basis beginning in 2020. Nucla Unit 4 will still comply with the 2011 RP determination of 0.5 lb/MMBtu (30-day rolling average) until closure.