Reasonable Progress (RP) Four-Factor Analysis of Control Options For Platte River Power Authority – Rawhide Energy Station

I. Source Description

Owner/Operator:	Platte River Power Authority
Source Type:	Electric Utility Steam Generating Unit
SCC (EGU):	1010026
Boiler Type:	Pulverized Coal Dry-Bottom Tangentially-Fired

The Platte River Power Authority (PRPA) Rawhide Energy Station is located in Larimer County approximately 10 miles north of the town of Wellington, Colorado. The Rawhide Energy Station consists of one coal fired steam driven electric generating unit (Unit 101), with a rated electric generating capacity of 305 MW (gross), and was placed into service in 1984. The boiler is equipped with a fabric filter (baghouse) system for controlling particulate matter (PM) emissions, and a lime spray dry absorber controls sulfur dioxide (SO_2). The boiler is equipped with low nitrogen oxide (NO_x) concentric firing system (LNCFS) burners with separated overfire air (SOFA) configuration for minimization of NO_x emissions, installed in 2005.

The Rawhide Station also has five natural-gas fired combustion turbines, designed to operate in a simple cycle mode, four rated at a heat input of 831.1 MMBtu/hour (approximately 82 MW) and one rated at a heat input of 1,400 MMBtu/hour (about 150 MW). Each turbine is equipped with integral dry low NO_x combustion systems and inlet air fog cooling systems and startup and shutdown duration average NO_x and CO emission limits determined to be Best Available Control Technology (BACT)[1] since each turbine is subject to Prevention of Significant Deterioration (PSD) provisions. These turbines were placed into service starting in May 2002, with the last turbine (150 MW) started up in June 2008. The primary use of these units is to meet Platte River's energy reliability and peak load requirements. The turbines operate on limited, intermittent, and unpredictable schedules as peak loading units. Additionally, the facility includes a number of fugitive dust sources. PRPA has prepared a Reasonable Progress (RP) analysis as well as supplemental information which can be found in "PRPA RP Submittals".

For this analysis, the Division also relied on the existing Title V permit, historical information regarding the Rawhide facility, and information about similar facilities to determine RP for PM_{10} and SO_2 (available in the TSD). 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 considered in making BART and RP determinations are largely the same.

For the purposes of evaluating RP, the Division has elected to set *de minimis* thresholds for any emission unit at a subject-to-RP source with actual baseline emissions of SO_2, NO_x, or PM_{10} equal

[1] Colorado Air Pollution Control Division, 2004. Colorado Operating Permit 03OPLR261: Rawhide Energy Station. Section II: Condition 1.7, pages 10 – 13.

to or exceeding the federal Prevention of Significant Deterioration (PSD) significance levels. The Division has established *de minimis* thresholds for SO_2, NO_x and PM_{10} to focus the technical emission control analysis on significant emission sources where potential controls could provide a meaningful improvement in visibility if emission controls are determined to be cost effective.

The *de minimis* levels are applicable to individual emission units at a stationary source. The Division defines "emissions unit" as "any part or activity of a stationary source that emits or has the potential to emit any air pollutant regulated under the state or Federal Acts. This term is not meant to alter or affect the definition of the term "unit" for purposes of Title IV (acid deposition control) of the federal act, or of the term "source" for purposes of the Air Pollutant Emission Notice requirements of Regulation Number 3, Part A, Section II.B.3. [2] ." 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

Emissions Unit P301 serves as a detailed example of evaluating one "unit" in Table 1. As the PM10 emissions from emissions unit P301 are below the *de minimis* level of 15 tons per year, it is exempted from any further analysis under RP.

Table 1: Unit Detail Example for *de minimis* Threshold

Unit P301 Breakdown	2006 – 2008 Average PM_{10} Emissions (Baseline Actual Emissions)
Solid Wastes Silo Rotary Unloader Discharge	0.41
Solid Wastes Hauling to Landfill	1.64
Solid Wastes Haul Truck Unloading	0.02
Active/Exposed Landfill Area	0.21
Waste Landfilling/Reclamation	0.39
Bottom Ash Excavation and Loading	0.02
Solid Wastes Silo Filling	0.00
Solids Vacuum Conveying System and Silo Filling	0.17
Fly Ash and Solid Waste Silo Dry Unloading and Haul Truck Loading	0.02
Unit P301 Baseline PM_{10} Emissions	3.01 << 15 (PSD threshold)

Rawhide Unit 101 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. PRPA submitted a "Rawhide NOx Reduction Study" on January 22, 2009 as well as additional relevant information on May 5 and 6, 2010. Table 2 depicts technical information for Rawhide Unit 101.

[2] 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.

Table 2: Rawhide Unit 101 RP-eligible Emission Controls and Reduction (%)

	Rawhide Unit 101
Placed in Service	1984
Boiler Rating, MMBtu/Hr for coal	3,000
Electrical Power Rating, Gross Megawatts	305
Description	Combustion Engineering tangentially fired, dry bottom steam generator/boiler firing pulverized coal.
Air Pollution Control Equipment	Fabric Filter (baghouse) for PM/PM_{10} control Spray Dryer Removal System for SO_2 control
Special Features	Low NO_x Concentric Firing System (LNCFS) with separated overfire air (SOFA) installed in 2005
Emissions Reduction (%)[1]	NO_x – 49.6% SO_2 – 83.1% PM/PM_{10} – 99.2/96.7%

[1]Emissions Reduction estimated by comparing uncontrolled AP-42 factor to actual average emission factor for PM/PM_{10}. For SO_2 estimates, CAMD data (average of 2006 – 2008) was used to calculate reduction %. The NO_x reduction is based on actual data from pre-2005 actual emissions. See "Rawhide APCD Technical Analysis" for further details. Not based on actual testing.

For the boiler, the Voluntary Emissions Reduction Agreement (VERA) permit limit for NO_x is 0.180 lbs/MMBtu on an annual average effective July 15, 2006. The Acid Rain permit limit for NO_x is currently 0.40 lbs/MMBtu on an annual average and the PSD/NSPS limit is 0.50 lbs/MMBtu on a 30-day rolling average.

In October of 2005, PRPA installed a low NO_x Concentric Firing System (LNCFS) with separated overfire air (SOFA) on Unit 101 that resulted in an approximate 50% reduction of NO_x emissions (from pre-2005 actual emissions) in accordance with the Voluntary Emissions Reduction Agreement entered into with the State of Colorado in 2002[3].

Rawhide Unit 101 was initially installed in 1984 with a baghouse for particulate emission (PM/PM_{10}) control, with control efficiency exceeding 99.9%. This system was BACT at the time of initial startup and is still considered BACT currently.

The "Spray Dryer Removal System" for Unit 101 was considered a new control technology at the time of installation in 1984 and started up at the same time as Rawhide Unit 101. This system originally reduced SO_2 emissions by approximately 80% and 0.13 lbs/MMBtu (30-day rolling average) (from AP-42 emission calculations) according to Federal PSD emission standards at that time (0.2 lbs/MMBtu annually). In 2003, PRPA entered into a Voluntary Emissions Reduction Agreement with the State of Colorado to reduce SO_2 emissions to 0.09 lbs/MMBtu (annual

[3] Colorado Air Pollution Control Division, 1992. Exhibit A: Division Evaluation of Nitrogen Oxides Emission Limitation and Regulatory Assurance Periods.

average) by upgrading the lime spray dryer system[4]. This upgraded system resulted in an approximate 30% emission rate reduction of SO_2 emissions from pre-VERA emission rates.

II. Source Emissions

Table 3 summarizes the NO_x, SO_2, and PM_{10} actual emissions averaged over the 2006 – 2008 baseline timeframe from EPA's CAMD Database for the facility. Table 4 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 APEN's submitted by the facility and as applicable, EPA's CAMD Database (primarily for the Unit 101 boiler and the turbines).

Table 3. Summary of 2006 - 2008 Averaged Emissions - PRPA Rawhide Facility

NO_x (tons/year)	SO_2 (tons/year)	PM_{10} (tons/year)
1,885	914	125

Table 4. Summary of 2006 - 2008 Averaged Emissions by Unit - PRPA Rawhide Facility

Unit	Pollutant	2006	2007	2008	2006 - 2008 average*
Unit 101 Boiler	SO_2 (tons)	943	928	869	913
	SO_2 (lb/ MMBtu)	0.078	0.081	0.078	0.081
	NO_x (tons)	1,990	1,863	1,745	1,866
	NO_x (lb/ MMBtu)	0.163	0.162	0.173	0.166
	PM_{10} (tons)	109	113	101	108
	PM_{10} (lb/ MMBtu)	0.018	0.017	0.018	0.018
Turbine Unit A (82 MW)	*SO_2 (tons)*	*0.10*	*0.12*	*0.12*	*0.11*
	NO_x (tons)	*1.17*	*5.45*	*0.75*	*2.46*
	PM_{10} (tons)	*0.20*	*1.12*	*0.13*	*0.48*
Turbine Unit B (82 MW)	*SO_2 (tons)*	*0.09*	*0.06*	*0.11*	*0.09*
	NO_x (tons)	*3.87*	*3.17*	*5.07*	*4.04*
	PM_{10} (tons)	*0.77*	*0.58*	*0.99*	*0.78*
Turbine Unit C (82 MW)	*SO_2 (tons)*	*0.04*	*0.09*	*0.03*	*0.05*
	NO_x (tons)	*2.03*	*4.45*	*1.65*	*2.71*
	PM_{10} (tons)	*0.33*	*0.80*	*0.30*	*0.48*
Turbine Unit D (82 MW)	*SO_2 (tons)*	*0.05*	*0.10*	*0.03*	*0.06*
	NO_x (tons)	*2.53*	*4.95*	*1.50*	*2.99*
	PM_{10} (tons)	*0.45*	*0.85*	*0.26*	*0.52*
*Turbine Unit F (150 MW)***	*SO_2 (tons)*			*0.38*	*0.38*
	NO_x (tons)			*20.45*	*20.45*
	PM_{10} (tons)			*3.75*	*3.75*
P201 Train Unloading Facility	*PM_{10} (tons)*	*0.60*	*0.01*	*0.01*	*0.20*
P201 Active Coal Pile Reclaim	*PM_{10} (tons)*	*0.03*	*0.02*	*0.00*	*0.02*
P201 Coal Silo Filling and Conveyor Belt Transfer	*PM_{10} (tons)*	*0.30*	*0.00*	*0.00*	*0.10*
P201 Coal Silo Discharge to Conveyor Belt	*PM_{10} (tons)*	*0.28*	*0.00*	*0.00*	*0.10*
P201 Coal Crushing and	*PM_{10} (tons)*	*0.33*	*0.02*	*0.02*	*0.12*

[4] Colorado Air Pollution Control Division, 1992. Exhibit B: Division Evaluation of Sulfur Dioxides Emission Limitation and Regulatory Assurance Periods.

Conveying					
P201 Coal Conveyor Belt Transfer	*PM_{10} (tons)*	*0.30*	*0.00*	*0.00*	*0.10*
P201 In-Plant Silo Filling Conveyor Belt Transfer	*PM_{10} (tons)*	*0.30*	*0.00*	*0.00*	*0.10*
P201 Coal Pile Stockout	*PM_{10} (tons)*	*1.18*	*0.01*	*0.02*	*0.40*
P201 Active Coal Storage Area	*PM_{10} (tons)*	*0.93*	*1.91*	*1.96*	*1.60*
P201 Active Coal Pile Storage Area	*PM_{10} (tons)*	*0.95*	*2.56*	*2.56*	*2.02*
P201 Coal Crusher Stockout	*PM_{10} (tons)*	*0*	*0*	*0*	*0.00*
P201 Coal Conveying	*PM_{10} (tons)*	*1.81*	*1.23*	*1.09*	*1.38*
P301 Solid Wastes Silo Rotary Unloader Discharge	*PM_{10} (tons)*	*0.70*	*0.28*	*0.25*	*0.41*
P301 Solid Wastes Hauling to Landfill	*PM_{10} (tons)*	*1.82*	*1.67*	*1.44*	*1.64*
P301 Solid Wastes Haul Truck Unloading	*PM_{10} (tons)*	*0.04*	*0.02*	*0.01*	*0.02*
P301 Active/Exposed Landfill Area	*PM_{10} (tons)*	*0.19*	*0.24*	*0.19*	*0.21*
P301 Waste Landfilling/Reclamation	*PM_{10} (tons)*	*0.13*	*0.57*	*0.46*	*0.39*
P301 Bottom Ash Excavation and Loading	*PM_{10} (tons)*	*0.03*	*0.02*	*0.02*	*0.02*
P301 Solid Wastes Silo Filling	*PM_{10} (tons)*	*0.02*	*0.20*	*0.17*	*0.13*
P301 Solids Vacuum Conveying System and Silo Filling	*PM_{10} (tons)*	*0.17*	*0.18*	*0.16*	*0.17*
P301 Fly Ash and Solid Waste Silo Dry Unloading and Haul Truck Loading	*PM_{10} (tons)*	*0.02*	*0.02*	*0.01*	*0.02*
P401 Scrubber Lime Storage Silo Filling	*PM_{10} (tons)*	*0*	*0.01*	*0.01*	*0.00*
P401 Recycle Ash Storage Silo Filling	*PM_{10} (tons)*	*0.11*	*0.89*	*0.81*	*0.60*
P501 Unpaved Site Roadways and Parking Lots	*PM_{10} (tons)*	*3.14*	*3.92*	*4.23*	*3.76*
P501 PRS Soda Ash Storage Silo Filling	*PM_{10} (tons)*	*0*	*0*	*0*	*0.00*

*The above emissions are for the most recent three years (2006 – 2008). These emissions are an **annual** average. 30-day rolling averages for the Unit 101 Boiler are estimated to be 5-15% higher than the annual average emission rate (i.e. the maximum 30-day NO_x rolling average is likely about 0.190 lbs/MMBtu).
**Note that Unit F did not start up until June of 2008; therefore it was not operated in 2006 or 2007 and for only half of 2008.

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

Each of the five turbines at Rawhide Station was installed with an advanced dry low-NO_x combustion system that controls NO_x emissions to less than 9 ppm @ 15% O_2 as well as a gas turbine inlet air fog cooling system designed for optimal power augmentation during hot weather operations. . Each turbine is subject to BACT under the PSD provisions. The turbines are also

required to use pipeline quality natural gas as defined by the Acid Rain Provisions 40 CFR Part 72. The Title V permit enforces a compliance SO_2 emission factor of 0.0006 lb/MMBtu for each turbine. These combustion turbines are further evaluated within the source category "Combustion Turbines" in Section 8.2.3 of the Regional Haze SIP.

III. Units Evaluated for Control

As documented by PRPA, Rawhide Unit 101 fires low sulfur, high heating value Power River Basin sub-bituminous coal. The specifications for the coal are listed below in Table 5.

Table 5: Coal Specifications (2006 - 2008 Averaged APEN data)

	Specifications		
Emission Unit	Fuel Heating Value (Btu/lb)	Sulfur (% by weight)	Ash (% by weight)
Rawhide Unit 101	8,853	0.24	5.42

Table 4 lists the units at Rawhide that the Division examined for control to meet reasonable progress requirements. Controlled and uncontrolled emission factors and APEN data were used to evaluate the control effectiveness of the current emission controls. Uncontrolled emission factors are outlined in Table 6.

Table 6: Uncontrolled emission factors for Rawhide Unit 101

Emission Unit	Pollutant	Fuel
		Coal (sub-bituminous) (lb/ton)
Rawhide Unit 101[5]	NO_x	7.2
	SO_2	35 x %S = 8.5*
	PM/PM_{10}	PM – 54.2** PM_{10} – 12.5

*%S = % of sulfur present in coal supply. For example, 35 x 0.24 = 8.5
**%A = % of ash present in coal supply. For example, 10 x 5.42 = 54.2

IV. Reasonable Progress Evaluation of Unit 101

a. Sulfur Dioxide

Step 1: Identify All Available Technologies

PRPA identified one SO_2 control option:

Fuel Switching – Natural Gas or Colorado Coal

The Division requested that PRPA evaluate the option below, and received relevant information for this request on May 5, 2010:

Dry FGD upgrades

As discussed in EPA's BART Guidelines[6], 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.

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

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

However, upgrades need to be considered for the scrubber 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

Step 2: Eliminate Technically Infeasible Options

Fuel Switching – Natural Gas or Colorado Coal: The Division and PRPA both assert that the Unit 101 boiler at Rawhide could convert fuels from coal to natural gas with boiler modifications and natural gas pipeline construction. Conversion from coal to natural gas would reduce SO_2 emissions by about 906 tons per year, or approximately 99% (using 2006 - 2008 CAMD data average)[7]. SO_2 emissions from coal combustion are affected by the chemical and physical properties of the feed coal. Feed coal characteristics significantly affect the design and operation of combustion controls, such as the existing LNB+SOFA system. With the dry FGD – lime spray dryer system in place, Unit 101 currently achieves an emission rate of 0.07 lb/MMBtu (annual average).

PRPA notes that Unit 101 is designed to burn PRB coal and the boiler is additionally optimized through a technologically complex process to burn this coal at very tightly controlled rate. PRPA has indicated that it is infeasible as well as economically impractical to change coal supplies. The sulfur content of the Rawhide Unit 101 PRB coal supply is between 0.8 – 1.4 lb/MMBtu with most of the supply containing less than 1.2 lbs/MMBtu (based on northern Wyoming PRB coal mine reports). The average sulfur content in the coal is 0.29%. PRPA obtains coal for Rawhide Unit 101 from the Antelope Mine in Converse County, Wyoming, which has one of the lowest sulfur content of any mine in the county. PRPA additionally pays a premium to ensure higher Btu/lower sulfur coal. A review by the Colorado Geological Survey found that on average, Wyoming coal had similar sulfur content to Colorado coal[8]. Virtually all Colorado coal contains less than 1 percent sulfur and most of it contains less than half of that amount (0.5% or less)[9]. Therefore, the sulfur content of the Antelope Mine coal is similar, if not lower, than Colorado coal.

The Division has determined that fuel switching to natural gas is technically feasible for Rawhide Unit 101. However, fuel switching to Colorado coal will not further reduce SO_2 emissions from Unit 101 and will not be considered further in this analysis.

Dry Flue Gas Desulfurization (FGD) Upgrades: Dry FGD systems are commonly known as spray dry absorbers (SDA), and currently make up about 12% of FGD systems at U.S. power

[7] Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D of the SIP for detailed calculations.
[8] Colorado Geological Survey: RockTalk. Volume One, Number Three. July 1998. http://geosurvey.state.co.us/pubs/rocktalk/rtv1n3.pdf
[9] Colorado Geological Survey: RockTalk. Volume One, Number Three. July 1998. http://geosurvey.state.co.us/pubs/rocktalk/rtv1n3.pdf

plants[10]. SDA systems are typically utilized at smaller units that burn lower-sulfur in the western U.S., where water resources are limited. A SDA system captures SO_2 by using a slaked lime containing slurry that is sprayed into the flue gas and reacts with the SO_2 to form calcium sulfate, and then is subsequently dried by the heat of the flue gas, and collected in a particulate control device.

Rawhide Unit 101 was installed in 1984 with a "Spray Dryer Removal System" in connection with the aforementioned baghouse for control of the resultant SDA materials. At the time, the system was a new control technology for SO_2 removal from the gaseous emission stream of a utility boiler. PRPA has since upgraded this system (in 2002) and currently achieves greater than 80% SO_2 removal, with an actual annual average of 0.07 lb/MMBtu and a permit limit of 0.09 lb/MMBtu on an annual average basis, 0.13 lb/MMBtu on a 30-day average, and 0.19 lbs/MMBtu on a 3-hour rolling average. This system exceeds EPA's presumptive limits stated in 40 CFR part 51 Appendix Y of 0.15 lb/MMBtu[11]. Lime spray dryers have been determined to be Best Available Control Technology (BACT) for new Electric Generating Unit (EGU) sources proposed in the West according to EPA's RBLC (RACT/BACT/LAER Clearinghouse) database. The RBLC database lists recent BACT determinations ranging from 0.06 – 0.167 lb/MMBtu, with an average of 0.11 lb/MMBtu on a 30-day rolling average. Refer to Appendix D for more details regarding recent RBLC BACT determinations. Additionally, an EPA Report regarding the control of SO_2 emissions found that lime spray drying processes have a range of design efficiencies from 70 – 96% and a median design efficiency of 90%; however, application conditions may differ (e.g. coal sulfur percent)[12] .

PRPA submitted a SO_2 upgrade analysis to the Division on May 6, 2010 upon request regarding potential upgrades for the dry FGD scrubber system. PRPA asserts that operating the SO2 scrubber at the 0.09 lbs/MMBtu VERA limit pushes many of the scrubber's material handling and slurry preparation sub-systems to the limits of their design capacity. As part of the VERA scrubber improvements, the recycle ash pressure feeders were upgraded and the recycle ash conveying line was replaced with larger diameter piping to increase the recycle ash conveying capacity between the solids waste silo and recycle ash storage bin/silo. Moving beyond current levels of scrubber operation would require additional equipment upgrades and would reduce the existing redundancy in some critical scrubber sub-systems. Specifically, the recycle ash blowers, bin vent filter on recycle ash silo, feed slurry preparation pumps, and feed slurry tanks are all operating at maximum throughput levels or at the margin and would need to be replaced with larger capacity equipment. While there is usually available redundancy within the lime slaking sub-system, a lower SO_2 limit would diminish this available capacity and likely also require an upgrade to ensure adequate margin.

PRPA notes that the SO_2 scrubber has three atomizer reaction compartments that provide critical operating flexibility. The scrubber generally operates with all three compartments in-service,

[10] 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.
[11] Colorado Operating Permit 96OPLR142 pg. 5 – SO_2 30-day rolling average limit is 0.13 lb/MMBtu.
[12] EPA, 2000. "Controlling SO_2 Emissions: A Review of Technologies." Prepared by Ravi K. Srivastava for Office of Research and Development, Washington, D.C. 20460. Pg. 33.

which provides maximum reaction/residence time, eases SO_2 removal equipment demands, and minimize pressure drop. Though not a desirable operating mode, the scrubber is currently capable of operating at full load with only two atomizer compartments in-service. In addition to the improved scrubber performance, the current atomizer compartment redundancy provides critical atomizer operational and maintenance flexibility, ensuring environmental compliance, and providing for high SO_2 scrubber and unit availability. Achieving a lower SO_2 limit may compromise atomizer compartment redundancy, which will significantly diminish scrubber operational and maintenance flexibility. This loss of redundancy and flexibility will likely result in increase malfunctions and could also affect unit availability if load reduction is triggered.

Even with the potential scrubber equipment upgrades, additional SO_2 reductions will still present unacceptable operational challenges. SO_2 scrubbing is limited by scrubber outlet temperatures which must remain above the fluegas dew point with an adequate margin to prevent condensation and catastrophic damage to the baghouse. Over-spraying below minimum SDA outlet temperatures also results in higher moisture ash in the baghouse that is difficult to convey from the collection hoppers.

Given existing spray-down temperature constraints, reducing SO_2 emissions below 0.09 lbs/MMBtu requires additional lime to increase feed slurry reactivity. At higher SO_2 removal rates, the lime/SO_2 stoichiometry increases and more unreacted lime is carried-over with the flyash and scrubber waste to the baghouse. The higher lime content in the flyash and scrubber waste affects the fluidity of the material making it harder to pneumatically convey out of and between the baghouse hoppers, solid waste silo, and recycle ash storage bin/silo. Hopper bridging and conveying piping pluggage are significant operational and maintenance issues impacting SO_2 scrubber reliability. Lowering the SO_2 emissions below the VERA limit will increase the potential for scrubber and baghouse malfunctions.

PRPA examined BART-guideline dry scrubbing potential upgrades, with the following results:

-*Use of performance additives*: Performance additives are typically used with dry-sorbent injection systems, not semi-dry SDA scrubbers that spray slurry products. PRPA and the Division are not aware of SO_2 scrubber performance additives applicable to the Unit 101 SDA system. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

-*Use of more reactive sorbent*: Lime quality is critical to achieving the VERA emission limit. PRPA utilizes premium lime at higher cost to ensure compliance with the VERA limit. The lime contract requires >92% reactivity (available calcium oxide) lime to ensure adequate scrubber performance. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

-*Increase the pulverization level of sorbent*: The fineness of sorbents used in dry-sorbent injection systems is a consideration and may improve performance for these types of scrubbers. Again, the Unit 101 SO_2 scrubber is a semi-dry SDA type scrubber that utilizes feed slurry that is primarily recycle-ash slurry with added lime slurry. PRPA recently completed SDA lime slaking sub-system improvements are designed to improve the reactivity of the slaked lime-milk slurry. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

-*Engineering redesign of atomizer or slurry injection system*: The Unit 101 SDA scrubber utilizes atomizers for slurry injection. The scrubber utilizes three reactor compartments, each with a single atomizer. PRPA maintains a spare atomizer to ensure high scrubber availability. The atomizers utilize the most current wheel-nozzle design. Therefore, this upgrade is not technically feasible for the dry scrubbing system.

The Division concludes that upgrades are not technically feasible for the Unit 101 Boiler.

Fuel switching to Colorado coal will not provide further SO_2 emission reductions. Rawhide Unit 101 has a SDA system for which the State has determined that no upgrades are feasible. Therefore, the Division has conducted a four-factor analysis for reasonable progress for fuel switching to natural gas regarding SO_2 reductions.

Step 3: Evaluate Control Effectiveness of Each Remaining Technology

Fuel Switching – Natural Gas: Conversion from coal to natural gas would reduce SO_2 emissions by almost 100% from the boiler using EPA's AP-42 emission factors[13] and concurs with PRPA's submittal.

Table 7 summarizes each available technology options and technical feasibility for SO_2 control on Rawhide Unit 101.

Table 7: Rawhide Unit 101 SO2 Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
Wet FGD	52-98%, median 90%[14]	Y – not evaluated
Dry FGD	70 – 90%	Y - installed
DSI (Trona)	60-65%	Y – not evaluated, will not provide further SO2 control
Fuel switching – different coal type	None	Y – will not provide further SO2 control
Use of performance additives	None	N
Use of more reactive sorbent	None	N
Increase the pulverization level of sorbent	None	N
Engineering redesign of atomizer or slurry injection system	None	N
Fuel switching – natural gas	99% (EPA AP-42)	Y

Step 4: Evaluate Factors and Present Determination

[13] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

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

Factor 1: Cost of Compliance

In 2008, Platte River performed a Unit 101 Natural Gas Conversion Study. The primary objective of the study was to determine required unit modifications and associated capital costs to co-fire the unit up to 100% using natural gas. The direct capital cost of converting to 100% natural gas was estimated to be about $50 million by PRPA[15]. This results in an initial control cost, using EPA's Cost Control Manual[16] to estimate annual operating costs, of about $262,000 per ton of SO_2 removed annually[17]. Changing to natural gas would dramatically raise fuel costs given that natural gas prices are approximately nine (9) times the cost of PRB coal and are subject to significant cost variability, which was not taken into account in the 2008 study[18].

To determine annualized costs of switching to natural gas, the annual electricity cost differentials between coal and natural gas were analyzed. PRPA notes that when using natural gas, fuel use will increase 17% annually due to anticipated efficiency drops, increased heat input requirements, and drop in generation. The annual electricity cost of coal is $25.5 million compared to natural gas at about $240 million when using 2008 commercial natural gas prices reported by the U.S. Energy Information Administration[19]. Therefore, this results in a significant annualized cost increase of $233 million. Refer to Appendix D for details.

Table 8 and Table 9 illustrate the resultant emissions and costs of switching fuel to natural gas, based on the difference between costs of coal and natural gas in 2008 and AP-42 emission factors.[20]

Table 8: Unit 101 Control Resultant SO_2 Emissions

Alternative	Control Efficiency (%)*	Resultant Emissions**	
		(tons/year)	(lb/MMBtu)
Baseline	---	913	0.08
Fuel Switching - NG	99%	7.7	0.0006

* Control efficiency calculated by the Division based on PRPA submittal of projected natural gas NO_x lb/MMBtu estimate.
** Division calculated from average baseline years (2006 – 2008). This is an **annual** average.

Table 9: Unit 101 SO_2 Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)*	Cost Effectiveness ($/ton)*	Incremental Cost ($/ton)
Baseline	0	$0	$0	n/a

[15] PRPA, February 18, 2010. "Re: Rawhide Unit 101 NOx Emissions Control Cost and Technical Feasibility Information Request – Additional Details and Explanation." Contained in Appendix D.
[16] EPA, 2002. EPA Air Pollution Control Cost Manual, Sixth Edition. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina, 27711.
[17] Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D for detailed calculations.
[18] PRPA, February 18, 2010. "Re: Rawhide Unit 101 NOx Emissions Control Cost and Technical Feasibility Information Request – Additional Details and Explanation." Contained in Appendix D.
[19] U.S. Energy Information Administration, 2010. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm
[20] AP-42, Fifth Edition, Volume I, Chapter 1, Section 1.4, Table 1.4-2. http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s01.pdf

Fuel Switching - NG	906	$237,424,331	$262,169	$262,169

* Division estimate based on PRPA submittal estimating direct capital cost at $50,000,000, current delivered coal costs at ~$20/ton, EPA Cost Control Manual, and EPA AP-42 emission factors for natural gas.

Platte River noted that the Division natural gas cost analysis does not account for replacement power for the lost generation. The Rawhide Natural Gas Conversion Study performed by B&V estimated that a 100% fuel switch would result in a loss of approximately 30 MW, in addition to the increased heat rate which was considered.

Platte River asserts that replacement power cost and associated emissions would depend on the specific source. Replacement with coal-fired sources would run in the $20 - $25/MWh range ($5.3 - $6.6 million/year), while natural gas-fired sources would run in the $60 - $125/MWh range ($15.8 – 32.8 million/year). Unaccounted NO_x emissions from the replacement power sources would likely be around 1.5 lbs/MWh (197 tons/year) for well combustion controlled coal-fired sources, and 0.36 lbs/MWh (47 tons/year) for natural gas-fired sources. The replacement power prices reflect current conditions and will need to be escalated over the 20-year 4-factor evaluation period. SO_2 emissions would likely be in the 0.7 lbs/MWh (92 tons/year) for well controlled coal-fired sources and 0.007 lbs/MWH (1 ton/year) for natural gas-fired sources. Table 7 below summarizes these costs and emissions.

Table 10: Unaccounted for Replacement Power Cost & Emissions Estimates (30 MW)

Power Source	Lower Cost ($/MWh)	Lower Cost ($ million/year)	Higher Cost ($/MWh)	Higher Cost ($ million/year)
Coal	$20	$5.26	$25	$6.57
Natural Gas	$60	$15.77	$125	$32.85
Power Source	NO_x (lbs/MWh)	NO_x (ton/year)	SO_2 (lb/MWh)	SO_2 (ton/year)
Coal	1.5	197	0.7	92
Natural Gas	0.36	47	0.007	1

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals[21], the Division anticipates that, taking into account the time necessary for completing design, permitting, procurement, pipeline installation, and system startup and shutdown, after SIP approval it would take PRPA approximately 2 – 3 years to convert the boiler from coal to natural gas. 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.

[21]Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. "Black Hills Clark Station NOx Reduction Feasibility Study." Pgs. 3-13 and 3-14.

Factor 3: Energy and Non-Air Quality Impacts

The Division has determined that there are not any negative energy or non-air quality related impacts related to fuel switching to natural gas for the Unit 101 boiler. Thus, this factor does not influence the selection of controls.

Factor 4: Remaining Useful Life

PRPA asserts that since Rawhide Unit 101 is one of the newest units in Colorado, it 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

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. **Error! Reference source not found.** depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

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

SO_2 Control Scenario	Unit(s)	SO2 Emission Rate (lb/MMBtu)	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hr SO_2 rates	101	0.11	RMNP	20	---	---	6	---	---
dry FGD	101	0.09		n/a					
dry FGD	101	0.07		20	19	1	6	4	2
Fuel Switching - NG	101	0.001		n/a					

Table 12: Visibility Results - SO2 Control Scenarios

SO2 Control Scenario	Unit(s)	SO2 Emission Rate	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum
		(lb/MMBtu)	(deciviews)	(deciviews)	(%)
Max 24-hr SO_2 rates	101	0.11	0.871		
dry FGD	101	0.09*	0.87	0.01	1%
dry FGD	101	0.07	0.84	0.03	3%
Fuel Switching - NG	101	0.001	0.00	0.87	100%

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

Determination

The Division evaluated emission limit tightening based on current operations through the four-factor analysis. PRPA's average 30-day rolling emission rate during the baseline period (2006 – 2008) was 0.09 lb/MMBtu. The maximum 30-day rolling emission rate during this period was 0.13 lb/MMBtu. Please refer to "Rawhide Cost Analysis" for more detail. The Division and PRPA agree that Rawhide can meet an emission limit of 0.11 lb/MMBtu (30-day rolling average).

Based upon its consideration of the five factors summarized herein, the state has determined that SO2 RP is the following SO2 emission rate:

Rawhide Unit 1: 0.11 lb/MMBtu (30-day rolling average)

The state has determined that these emissions rates are achievable without additional capital investment. Upgrades to the existing SO2 control system were evaluated, and the state determines that meaningful upgrades to the system are not available. Lower SO2 limits would not result in significant visibility improvement (less than 0.02 delta deciview) and would likely result in frequent non-compliance events and, thus, are not reasonable.

b. Filterable Particulate Matter (PM_{10})

PRPA Unit 101 is currently equipped with two twelve-compartment fabric filter baghouses 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.

PRPA states that the baghouses are able to control PM/PM_{10} emissions to 0.03 lb/MMBtu and further notes that that the baghouses meet a 99.9+% control efficiency. The source was tested on November 18, 2009 and ran at 0.0023 lb/MMBtu, 92% lower than the permit limit (Method 5 – filterable portion). 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. 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.

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 well within the range of recent BACT determinations.

The State has determined that the existing Unit 101 regulatory emissions limits of 0.03 lb/MMBtu (PM/PM10) represents the most stringent control option. The state assumes that the emission limit can be achieved through the operation of the existing fabric filter baghouses. The unit is exceeding a PM control efficiency of 95%, and the control technology and emission limit is RP for PM/PM_{10}. Thus, as described in EPA's BART Guidelines, a full four-factor analysis for PM/PM_{10} is not needed for Rawhide Unit 101.

c. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies
PRPA identified eight NO_x control options:
Fuel Switching – Natural Gas
Selective non-catalytic reduction (SCNR)
Selective catalytic reduction (SCR)
Separated overfire Air (SOFA)
Low NO_x Burners (LNB)
LNB + SOFA
ECC – Enhanced Combustion Control

The Division also identified and examined the following additional control options:
Electro-Catalytic Oxidation (ECO)®
Rich Reagent Injection (RRI)
Coal reburn +SNCR

Rotating overfire air (ROFA) was not considered in this analysis because ROFA® technology has been reported as achieving NO_x emission reductions from 45 to 65 % based on fuel load[22]. While ROFA is considered superior to SOFA alone, ROFA alone is not superior to LNB+OFA and cannot achieve the greater than 70% NO_x reduction already being achieved at Unit 101. Since ROFA® technology would not be expected to provide better emissions performance than the LNB+OFA baseline for this unit, ROFA® technology is not considered further in this analysis.

Step 2: Eliminate Technically Infeasible Options

Fuel Switching – Natural Gas: The Unit 101 boiler at Rawhide could convert fuels from coal to natural gas with boiler modifications. NO_x emissions from coal combustion are affected by the chemical and physical properties of the feed coal. Feed coal characteristics significantly affect the design and operation of combustion controls, such as the existing LNB+SOFA system. With the LNB+SOFA system in place, Unit 101 currently achieves an emission rate of 0.17 lb/MMBtu (annual average).

PRPA notes that Unit 101 is designed to burn PRB coal and the boiler is additionally optimized through a technologically complex process to burn this coal at very tightly controlled rate. PRPA has indicated that it is infeasible and economically impractical to change coal supplies. With fuel switching to natural gas, NO_x emissions were projected to drop from the current 0.17

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

lbs/MMBtu to a rate of 0.1 lbs/MMBtu[23]. However, this reduction would be diminished by the accompanying loss in boiler efficiency, increased boiler heat input requirement, and significant loss of generation resulting from natural gas firing.

The Division has determined that fuel switching to natural gas is technically feasible for Rawhide Unit 101.

LNB/ROFA®/SOFA/LNB+SOFA: The boiler is already equipped with a tangentially-fired LNB+SOFA system that was installed in 2005. This system achieves an approximate 50% NO_x reduction (based on actual emissions).

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. 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. The optimum temperature window for Rawhide Unit 101 will most likely occur somewhere at the top of the furnace and in the backpass of the boiler if SNCR is applied. SCNR is considered a technically feasible alternative for Unit 101.

SCR: SCR systems are the most widely used post-combustion NO_x control technology. In retrofit SCR systems, vaporized ammonia (NH_3) injected into the flue gas stream acts as a reducing agent, achieving NO_x emission reductions as low as 0.07 lb/MMBtu when passed over an appropriate amount of catalyst as demonstrated by recent determinations found in the EPA's RBLC database. The NO_x and ammonia reagent form nitrogen and water vapor. The reaction mechanisms are very efficient with a reagent stoichiometry of approximately 1.0 (on a NO_x reduction basis) with very low ammonia slip.

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 and would likely be the arrangement for Unit 101 if applicable. For high- and low-dust arrangements, the catalyst, because of its location directly downstream of the boiler and upstream of the air heater, can impact the boiler through its effect on the air heater. The magnitude of this effect is dependent on the power plant configuration, air quality control components, type of fuel, and overall emission control requirements. For retrofit applications, adequate space between the economizer outlet and the air heater inlet to allow boiler outlet and air heater return duct is a prerequisite for the installation of a high-dust system and is the case at the Rawhide Station. Therefore, high-dust SCR is a technically feasible alternative for Rawhide Unit 101.

[23] PRPA, February 18, 2010. "Re: Rawhide Unit 101 NOx Emissions Control Cost and Technical Feasibility Information Request – Additional Details and Explanation." Contained in Appendix D.

ECC: The enhanced combustion control system option for Rawhide Unit 101, submitted by PRPA, consists of a neural-net based combustion optimization subsystem (software and hardware) and companion real-time boiler combustion constituents and temperature measurement system. These system components are interfaced with the boiler's standard coordinated combustion control system (CCS). The ECC system continuously measures and monitors the dynamic boiler combustion constituents, temperatures and other process parameters. The ECC system then commands the CCS to manipulate variables such as combustion air damper positions, burner tilts, coal feeder speeds, and other process parameters to optimize fuel combustion and boiler efficiency, while controlling NO_x and CO emissions within targeted ranges. Optimizing the ECC requires periodic combustion testing and CCS tuning. ECC is a technically feasible option for Rawhide Unit 101.

ECO®: The Powerspan ECO® system is installed downstream of a coal-fired power plants' existing baghouse. The ECO® Reactor then oxidizes pollutants, which are removed downstream in an absorber vessel during cooling and saturation of the flue gas. This technology has not been demonstrated on a full-size pulverized coal-fired boiler[24] and thus, is considered technically infeasible.

RRI: Rich reagent injection is the process of adding NO_x reducing agents in a staged lower furnace to reduce the formation of NO_x, accomplished by injecting urea into the fuel-rich region of a furnace, where the reducing conditions in the lower furnace make RRI ideal for NO_x reductions. The combustion process is then completed with the use of overfire air. Rich reagent injection was developed for cyclone boilers[25] and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Unit 101.

Coal Reburn + SNCR: Several research and development efforts in the United States evaluated using a combination of technologies to reduce NO_x emissions, including combining coal reburn and SNCR. A novel injection procedure into the fuel-rich, post-combustion zone with staged, fuel-rich primary combustion and SNCR injection was found to reduce NO_x emissions by 93% or well below 0.1 lb/MMBtu[26]. 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

Fuel Switching – Natural Gas: The Unit 101 boiler at Rawhide could convert fuels from coal to natural gas with boiler modifications. Conversion from coal to natural gas would reduce NO_x emissions by about 545 tons per year, or approximately 29% (using 2006 - 2008 CAMD data average)[27].

[24] Powerspan ECO®: Overview and Advantages, 2000 – 2010. http://www.powerspan.com/ECO_overview.aspx
[25] Fuel Tech: Air Pollution Control – Rich Reagent Injection (RRI), 1998 – 2009. http://www.ftek.com/apcRRI.php
[26] Coal Tech. Corp, 2002. "Tests on Combined Staged Combustion, SNCR & Reburning for NOx Control and Combined NOx/SO2 Control on an Industrial & Utility Boilers." http://www.netl.doe.gov/publications/proceedings/04/NOx/summary/h11.50zauderer-summary.pdf
[27] Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D for detailed calculations.

SNCR: Other Colorado facilities have noted a variety of control ranges for SNCR. The Division used a variety of information, including a similar Colorado facility estimates, EPA's SNCR Air Pollution Control Fact Sheet and a recent AWMA study[28] to conservatively approximate that Rawhide Unit 101 can achieve up to 30% control when SNCR is applied. PRPA asserts that NO_x reductions of up to 60% have been achieved, although 20-40% is more realistic for most applications. However, if ammonia slip is controlled closer to 2 ppm then achievable NO_x reduction efficiencies will be closer to 20 percent.

*SCR:*PRPA approximates that SCR can achieve an approximate 64% NO_x reduction from the current low 0.17 lb/MMBtu baseline emission rate. PRPA asserts that while a lower controlled NO_x emission values have been demonstrated by SCR system applications in new coal units, for PRPA, a retrofit SCR, the 0.07 lb/MMBtu controlled NO_x value is more expected. This control efficiency is slightly lower than EPA's AP-42 emission factor discussion, which estimates SCR as achieving 75 – 85% NO_x emission reductions and also with a recent AWMA study citing SCR as achieving 80 – 90% reduction from an assumed baseline emission rate of 0.5 lb/MMBtu.[29,30] However, in the Division's experience and national CAMD emissions data (2009) reflect that an emission limit of no lower than 0.07 lb/MMBtu is realistically achievable for a retrofit SCR.

Table 13 summarizes each available technology and technical feasibility for NO_x control.

Table 13: Rawhide Unit 101 NOx Technology Options and Technical Feasibility

Technology	Emission Reduction Potential (%)	Technically Feasible? (Y = yes, N = no)
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%	Y – will not increase current NO_x reductions
SCNR	20 – 40%	Y
SCR – HTSCR	Up to 90%	Y-high-dust arrangement
SCR – LTSCR		
SCR – RSCR		
Fuel switching – Natural gas	20-70%	Y
Electro-Catalytic Oxidation (ECO)®	n/a	N
Rich Reagent Injection (RRI)	n/a	N
Coal reburn+SNCR	n/a	N
ECC	15-25%	Y

[28] Srivastava et. al, 2005. Nitrogen Oxides Emission Control Options for Coal-Fired Electric Utility Boilers. Journal of Air & Waste Management Association 55:1367 – 1388.
[29] 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
[30] 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 Factors and Present Determination

Factor 1: Cost of Compliance

SNCR: A typical breakdown of annual for industrial boilers will be 15 – 35% for capital recovery and 65 – 85% for operating expense.[31] The PRPA-estimated SNCR costs for operating expenses is 44% for Unit 1. Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. The cost effectiveness for SNCR on Unit 1 is $3,168 per ton NO_x reduced. Recent NESCAUM studies estimate SNCR retrofits achieving NO_x emission rates of 0.30 – 0.40 lb/MMBtu and emission reductions of 30 – 50% as costing $630 - $1,300 per ton of NO_x reduced, depending on initial capital costs and capacity factor.[32,33] EPA's SNCR Fact Sheet cites SNCR as costing from $400 - $2,500 per ton of NO_x reduced.[34]

Platte River relies on Black and Veatch's (B&V) expertise and cost estimates on major projects. Platte River contracted with B&V to perform a detailed study to provide capital costs for NOx emissions reduction alternatives for the Rawhide Unit 101. The *Rawhide NOx Reduction Study, January 2009* noted that the SNCR costs were based on actual B&V engineering, procurement, and contracting projects. Rawhide specific SNCR project cost considerations were:

-
- Rawhide's geographic location, economies of scale and small size of Rawhide Unit 101
- Three levels of automatic injection lances with retract system to accommodate SNCR reaction temperature and boiler turndown requirements.
- Computer flow/temperature modeling to establish optimum ammonia injection locations and flow patterns,
- Boiler waterwall modifications for injector lances and steam piping modifications for performance optimization,
- Electrical Motor Control Center switch gear upgrades and modifications to support urea system and ammonia delivery system,
- Reagent storage tank,
- Digital Control System (DCS) computer system hardware and control logic upgrades,
- Fluegas temperature and NOx and ammonia continuous emission monitoring, data acquisition, alarming and reporting system,
- Interest costs during construction, and
- Use of a more expensive urea reagent system rather than anhydrous ammonia due to safety and transport concerns.

[31] ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions." Washington, D.C. 2000.
[32] Neuffer, Bill – ESD/OAQPS, 2003. "NO_x Controls for Existing Utility Boilers." http://www.epa.gov/ttn/nsr/gen/u3-26.pdf
[33] Amar, Praveen, 2000. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines: Technologies & Cost Effectiveness." Northeast States for Coordinated Air Use Management, 129 Portland Street, Boston, MA 02114.
[34] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf

Platte River notes that the SNCR cost effectiveness ($/ton removed) remains comparatively high due to Rawhide's low baseline NO_x emission rates for the above reasons.

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.[35] Although PRPA's estimates are greater than these ranges, the reasons above lead the Division to the conclusion that PRPA's cost estimates for SNCR are reasonable.

SCR: SCR reagent materials, such as urea and/or ammonia, primarily use a limited resource, natural gas. Therefore, future costs for these materials may fluctuate widely. These costs are not included in the overall $/ton projections.

EPA's regulations recommend using the EPA's Office of Air Quality Planning and Standards' Air Pollution Cost Control Manual (Sixth Edition, January 2002) for estimating costs of compliance. This Manual provides guidance and methodologies for developing accurate and consistent estimates of cost for air pollution control devices. The costs that may be estimated include capital costs, operation and maintenance (O&M) expenses, and other annual costs.

In reviewing PRPA's estimate, the Division found that the ratio of annual costs to the total capital costs for all control technologies projected by PRPA to be slightly lower than those projected by other facilities that were amortized over the same 20 year time frame. For example, the annualized costs for SCR for Unit 101 are 10.5% of the total capital investment. The EPA found that other facilities in Arizona, New Mexico, and Oregon presented annual costs that ranged from 12 – 15% of total capital investments[36]. Therefore, the Division concurs that PRPA's estimate is consistent with annual costs estimated by other facilities.

Platte River relies on Black and Veatch's (B&V) expertise and cost estimates on major projects. Platte River contracted with B&V to perform a detailed study to provide capital costs for NOx emissions reduction alternatives for the Rawhide Unit 101. The *Rawhide NOx Reduction Study, January 2009* noted that the SCR costs were based on actual B&V engineering, procurement, and contracting projects. Rawhide specific SCR project cost considerations were:

- Vertical oriented high-dust SCR reactor configuration,
- Construction crane access constraints due to north-side coal conveyor and ACI silo, and south-side underground 84 inch circulating water line,
- Preliminary design and layout analyses including foundations, structural columns, cantilevered support steel, and main trusses support structures,
- Modification to existing structures including demolition of ductwork between the economizer and the air heater inlet,
- Rawhide's geographic location, economies of scale and small size of Rawhide Unit 101,

[35] EPA, 2003. "SNCR Air Pollution Control Technology Fact Sheet." http://www.epa.gov/ttn/catc/dir1/fsncr.pdf
[36] 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.

- Induced draft (ID) fan higher hp motor replacement and retrofit issues,
- Auxiliary power and switch gear upgrades and modifications to support two new ID fan motors,
- Digital Control System (DCS) computer system hardware and control logic upgrades including new electrical and controls building located adjacent to SCR,
- NOx and ammonia continuous emission monitoring, data acquisition, alarming and reporting system,
- Three layer (two catalyst and one initial spare) reactor sizing for maximizing catalyst utilization,
- Reactor design to accommodate both ceramic honeycomb and plate type catalyst products to insure future procurement flexibility,
- Rerouted underground utilities (bottom-ash sluice trench and drain piping) due to SCR foundation requirements,
- Added superstructure costs due to fully enclosed plant, including boiler and air heater areas for cold-weather concerns requiring roof and wall penetrations and modifications,
- Higher structural costs due to high wind loading ,
- High gas temperature design issues (>800°F economizer gas temperature results in higher grade catalyst and steel issues), and
- Use of a more expensive urea reagent system rather than anhydrous ammonia due to safety and transport concerns,
- Interest costs during construction, and
- Lost generation revenue costs during outage.

Platte River notes that the SCR cost effectiveness ($/ton removed) remains comparatively high due to Rawhide's low baseline NO_x emission rates for the above reasons. The Division asserts that $/KW is not an appropriate metric when a detailed cost estimate has be developed. $/KW is rough estimate of controls for back of the envelope discussions and should not serve as cost estimate in light of more refined estimates. Therefore, the Division did not adjust PRPA's estimates for capital costs.

Fuel Switching – Natural Gas: In 2008, Platte River performed a Unit 101 Natural Gas Conversion Study. The primary objective of the study was to determine required unit modifications and associated capital costs to co-fire the unit up to 100% using natural gas. The direct capital cost of converting to 100% natural gas was estimated to be about $50 million. Conversion from coal to natural gas would reduce NO_x emissions by about 545 tons per year (using 2006 - 2008 CAMD data average). This results in an initial control cost, using EPA's Cost Control Manual to estimate annual operating costs, of about $436,000 per ton of NO_x removed annually[37]. Changing to natural gas would dramatically raise fuel costs given that natural gas prices are approximately nine (9) times the cost of PRB coal and are subject to significant cost variability. Tables 9 and 10 illustrate the resultant emissions and costs of switching fuel to natural gas, based on the difference between costs of coal and natural gas in 2008 and AP-42 emission factors. The annual cost to control was determined using a capital

[37] Colorado Air Pollution Control Division Technical Analysis – Rawhide Unit 101 Boiler – Natural Gas Switching, 2010. See Appendix D SIP for detailed calculations.

recovery factor based on an approximate 8% interest rate. Refer to "Rawhide Cost Analysis" for more details.

To determine annualized costs of switching to natural gas, the annual electricity cost differentials between coal and natural gas were analyzed. PRPA notes that when using natural gas, fuel use will increase 17% annually due to anticipated efficiency drops, increased heat input requirements, and drop in generation. The annual electricity cost of coal is $25.5 million compared to natural gas at about $240 million when using 2008 commercial natural gas prices reported by the U.S. Energy Information Administration[38]. Therefore, this results in a significant annualized cost increase of $233 million. Refer to Appendix D for details.

ECC: PRPA worked with three different vendors on an enhanced combustion control pilot system. The cost estimates provided are from this pilot project. The annualized cost of approximately $288,500 is much lower than SNCR, which achieves about the same amount of control. This is little available cost information regarding this type of boiler modification. Since the costs are comparable or lower than other pre-combustion technologies, the Division concurs that PRPA's cost estimate is reasonable.

Table 14 and Table 15 depict controlled NO_x emissions and control cost comparisons.

Table 14: Unit 101 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	---	1,866	0.166	
ECC	24.0	1,418	0.126	0.145
SNCR	27	1,362	0.121	0.140
Fuel Switching - NG	29.2**	1,321	0.118	0.135
SCR	63.5	681	0.061	0.070

* Control efficiency calculated by the Division based on PRPA submittal of projected natural gas NO_x lb/MMBtu estimate.
** Control efficiency provided in PRPA's analysis based on 0.17 lb/MMBtu NO_x input, equivalent to 2006 – 2008 baseline conditions. Refer to "Rawhide Cost Analysis" for more information.

Table 15: Unit 101 NO_x Cost Comparison

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baseline	0	$0	$0	---

[38] U.S. Energy Information Administration, 2010. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_a.htm

ECC	448	$ 288,450	$644	$644
SNCR	504	$1,596,000	$3,168	$23,357
Fuel Switching - NG	545	$237,424,331	$435,681	$5,735,260
SCR	1,185	$12,103,000	$10,214	($352,073)

Factor 2: Time Necessary for Compliance

Based on other Colorado facility submittals[39], 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 PRPA approximately 2 – 3 years to convert the boiler from coal to natural gas. 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.

PRPA anticipates that the time necessary for completing design, permitting, procurement, control equipment installation, and system startup and shakedown, after SIP approval, would be approximately 2-3 years for SNCR and 3-4 years for SCR. These timeframes may also vary somewhat to schedule the necessary major maintenance outage with other regionally affected utilities. The ECC option timeframe is much shorter due to the fact that PRPA has already been working with independent vendors on this system. Therefore, this system could be functional within 6 months of SIP approval.

Factor 3: Energy and Non-Air Quality Impacts

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 and SNCR reagent injection system have minimal power requirements.

Post-combustion add-on control technologies like SCR and 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. In particular, 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. 100 – 300 kW is less than 0.5% of the power generated by the Unit 101 boiler annually, or enough energy to power about 10 homes for a year. These energy requirements are minimal.

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

[39] Prepared for Black Hills Colorado Electric by CH2M Hill, December 2009. "Black Hills Clark Station NOx Reduction Feasibility Study." Pgs. 3-13 and 3-14.

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. PRPA has indicated to the Division that they would prefer to use urea instead if applicable to ensure personnel and surrounding community safety, and based the capital and operating costs of a SCR system on a urea reagent versus an ammonia reagent. Refer to Appendix D for more information.

Factor 4: Remaining Useful Life

PRPA asserts that since Rawhide Unit 101 is one of the newest units in Colorado, it will remain in service for the 20-year amortization period. Thus, this factor doesn't influence the selection of controls.

Factor 5 (optional): 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 16 shows the number of days pre- and post-control. Table 17 depicts the visibility results (98th percentile impact and improvements) as well as cost effectiveness in $/deciview and the calculation methodology utilized by the Division.

The state performed modeling using the maximum 24-hour rate during the baseline period, and compared resultant annual average control estimates. In the state's experience and other state BART proposals, 30-day NOx rolling average emission rates are expected to be approximately 5-15% higher than the annual average emission rate. The state projected a 30-day rolling average emission rate increased by 15% for all NOx emission rates to determine control efficiencies and annual reductions.

Table 16: Visibility Results - Change in Days >0.5 dv and >1.0 dv at highest affected Class I Area

NOx Control Scenario	Boiler	NOx Emission Rate (lb/MMBtu)*	Class I Area Affected	3-year totals			3-year totals		
				Pre-Control Days >0.5 dv	Post-Control Days >0.5 dv	Δdays	Pre-Control Days >1.0 dv	Post-Control Days >1.0 dv	Δdays
Max 24-hr NOx rate	101	0.302	Rocky Mountain National Park	20	---	---	6	---	---
ECC	101	0.126		20	6	14	6	1	5
SNCR	101	0.121*		n/a					
Fuel Switching - NG	101	0.118*		n/a					
SCR	101	0.061		20	1	19	6	0	6

Table 17: Visibility Results - NOx Control Scenarios

NOx Control Scenario	Boiler	NOx Emission Rate (lb/MMBtu)*	Output (@ 98th Percentile Impact)	98th Percentile Impact Improvement	98th Percentile Improvement from Maximum	Cost Effectiveness
			(dv)	(Δ dv)	(%)	($/dv)
Max 24-hr NOx rate	101	0.302	0.87	---	---	---
ECC	101	0.126	0.42	0.45	52%	$642,428
SNCR	101	0.121*	0.41	0.46	53%	$3,469,565
Fuel Switching - NG	101	0.118*	0.41	0.47	54%	$509,494,272
SCR	101	0.061	0.28	0.59	68%	$20,548,387

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

Determination

Based upon its consideration of the five factors summarized herein, the State has determined that NOx RP for Rawhide Unit 101 is the following NOx emission rate:

Rawhide Unit 1: 0.145 lb/MMBtu (30-day rolling average)

The state assumes that the RP emission limits can be achieved through the operation of enhanced combustion control. The dollars per ton control cost, coupled with notable visibility improvements, leads the state to this determination. Although SCR achieves better emission reductions, the expense of SCR was determined to be excessive and above the guidance cost criteria discussed in section 8.4 above. SNCR would achieve similar emissions reductions to enhanced combustion controls and would afford a minimal additional visibility benefit (0.01 delta deciview), but at a significantly higher dollar per ton control cost compared to the selected enhanced combustion controls, so SNCR was not determined to be reasonable by the state.