James M Parker, PE, Manager ECS
6640 Southridge Road, Billings, MT 59101,
james.parker@talenenergy.com, 406 281 2999

VIA E-MAIL: CHenrikson@mt.gov

September 30, 2019

Mr. Craig Henrikson, P.E.
Environmental Engineer, Permitting Services Section
Air Quality Bureau, Montana Department of Environmental Quality
1520 E. 6th Avenue
Helena, MT 59601

Re: Regional Haze Reasonable Progress Analysis – Talen Montana, LLC, Colstrip Steam Electric Station

Dear Mr. Henrikson:

Please find attached the Talen Montana, LLC (Talen) Colstrip Steam Electric Station (Colstrip Plant) reasonable progress four factor analysis and report. This report is being submitted in response to the April 19, 2019 letter from the Montana Department of Environmental Quality, Air Quality Bureau (AQB) requesting information for the AQB's reasonable progress analysis. We hope you find the report informative to your process.

Talen believes that, based on the four factor analysis completed in the attached report, there are no controls that should be installed at Colstrip Units 3 and 4 for reasonable progress purposes.

If you have any questions or comments about the information presented in this letter, please do not hesitate to call me at (406) 281-2999 or Ashley Jones, Trinity Consultants, at (720) 638-7647 ext.103.
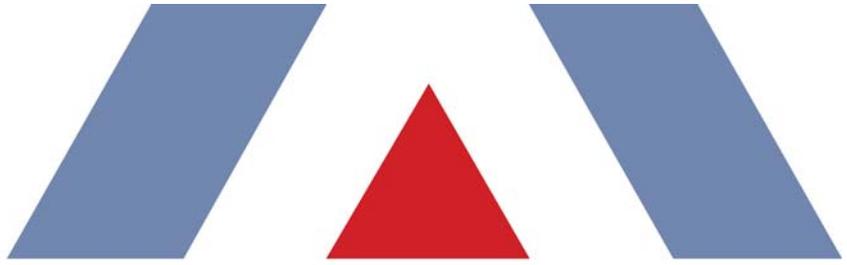
Sincerely,

James M Parker, PE
Manager, ECS

Attachments

cc: Mr. Gordon Criswell, Talen Montana, LLC
     Mr. Brian Sullivan, Talen Montana, LLC
     Ms. Ashley Jones, Trinity Consultants

PROJECT REPORT

Talen Montana, LLC > Colstrip, MT

TALEN MONTANA

REASONABLE PROGRESS FOUR FACTOR ANALYSIS

Prepared By:

TALEN MONTANA, LLC
580 Willow Avenue
Colstrip, MT 59323
(406) 740-0211

TRINITY CONSULTANTS
1391 N Speer Blvd
Suite 350
Denver, CO 80204
(720) 638-7647

September 2019

Trinity Consultants

Environmental solutions delivered uncommonly well

TABLE OF CONTENTS

This report documents the results of a four factor control analysis at the Talen Montana, LLC (Talen) Colstrip Steam Electric Station (Colstrip Power Plant). The Colstrip facility has four (4) tangential coal-fired boilers and associated equipment for generation of electricity. This report is provided in response to the Montana Department of Environmental Quality (DEQ) request letter dated April 19, 2019.

Talen previously submitted a best available retrofit technology (BART) assessment for Colstrip Units 1 and 2 in 2007, and a four factor analysis for the first regional haze planning period for Colstrip Units 1 – 4 in 2011. This analysis will focus on Units 3 and 4, as Units 1 and 2 are required to shut down by July 1, 2022[1], and, as of this submittal there is potential that Units 1 and 2 could shut down as early as the end of 2019. This analysis of Units 3 and 4 serves as an update to the previous analysis done in 2011, accounting for the latest advances in control technology and control costs.

The U.S. Environmental Protection Agency's (EPA's) guidelines in 40 CFR 51.308 were used to evaluate control options for Units 3 and 4. In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A).

The purpose of this report is to provide information to DEQ regarding potential sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emission reductions for Colstrip Units 3 and 4 for the purpose of establishing reasonable progress goals at mandatory Class I areas set as a result of the regional haze rule (RHR) to meet the uniform rate of progress (URP) glide path for each mandatory Class I area. Talen believes that, based on the four factor analysis, there are no controls that should be installed at Colstrip Units 3 and 4 for reasonable progress purposes.

Currently, Units 3 and 4 use low NO_X burners, separate overfire air (SOFA), and Smartburn® technology to lower NO_X emissions, and use low sulfur coal (<1% sulfur) and wet scrubbers with additional lime injection to reduce SO_2 emissions. Colstrip's wet scrubbers can achieve 95% reduction, as needed, to meet current emission limits. Furthermore, Talen has no provisions for scrubber bypass, and a spare scrubber vessel per unit is available for service. We should also note that Units 3 and 4 were both permitted under EPA's prevention of significant deterioration (PSD) program and were determined to meet best available control technology (BACT) for both NO_X and SO_2 at the time the permit was issued and the sources constructed.

The report identifies the following potential control technologies for Colstrip Units 3 and 4 to be evaluated further:

NO_X Emission Controls
> Selective Noncatalytic Reduction (SNCR): Initial capital investment for the installation of the SNCR would be approximately $17.8 million, with a cost effectiveness of approximately $10,234/ton of NO_X removed. As such, this technology is deemed economically infeasible.

---

[1] Title V Operating Permit OP0513-14, Permit Condition B.4.d and Montana Board of Environmental Review Board Order make the July 1, 2022 permanent shutdown of Colstrip Units 1 and 2 federally enforceable. https://deq.mt.gov/Portals/112/Public/Air/BoardOrder_Exhibit%20A_Talen.pdf

- > <u>Selective Catalytic Reduction (SCR):</u> Initial capital investment for the installation of the SCR would be approximately \$310.9 million, with a cost effectiveness of approximately \$12,858/ton of NO_X removed. As such, this technology is deemed economically infeasible.

SO_2 Emission Controls
- > No new add-on controls were identified.

.

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final RHR. The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as federal Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977. These 156 areas are also known as mandatory Class I areas.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each mandatory Class I area in their state[2]. In establishing a reasonable progress goal for a mandatory Class I area, the state must:

> (A) *consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal. 40 CFR 51. 308(d)(1)(i)(A).*

> (B) *Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction. 40 CFR 51. 308(d)(1)(i)(B).*

With the second planning period under way for regional haze, there are a few key distinctions from the processes that took place during the first planning period. Most notably, the planning period 2 analysis will distinguish between "natural" and "anthropogenic" sources. Using a Photochemical Grid Model (PGM), the EPA will establish what are, in essence, background concentrations both episodic and routine in nature and will compare manmade source contributions against these natural background concentrations.

On April 19, 2019, Montana DEQ sent a letter to Talen requesting that they assist in "developing information for the reasonable progress analysis" for Talen's Colstrip facility.[3] Talen understands that the information provided in a four factor review of control options will be used by DEQ in their evaluation of reasonable progress goals for Montana. Talen assumes that EPA and DEQ will only move forward with requiring additional emission reductions from the Colstrip Units 3 and 4 if the emission reductions can be demonstrated to be needed to show further reasonable progress towards the goals established. The purpose of this report is to analyze potential SO_2 and NO_X emission controls for Colstrip Units 3 and 4 based on the four reasonable progress factors.

---

[2] After initially withdrawing efforts to adopt a state implementation plan (SIP) in 2006, the Montana DEQ operated under a Federal Implementation Plan (FIP) developed by the EPA through 2018. Montana DEQ is now transitioning back to an SIP for addressing the requirements for regional haze under 40 CFR 51.308.

[3] Refer to letter from Montana DEQ to Talen dated April 19, 2019.

The information presented in this report considers the following four factors for the emission reductions:

> Factor 1. Costs of compliance;
> Factor 2. Time necessary for compliance;
> Factor 3. Energy and non-air quality environmental impacts of compliance; and
> Factor 4. Remaining useful life of Units 3 and 4.

Factors 1 and 3 of the four factors that are listed above were considered by conducting a step-wise review of emission reduction options in a top-down fashion similar to the top-down approach that is included in the EPA RHR guidelines[4] for conducting a review of BART for a unit[5]. These steps are as follows:

> Step 1. Identify all available retrofit control technologies;
> Step 2. Eliminate technically infeasible control technologies;
> Step 3. Evaluate the control effectiveness of remaining control technologies; and
> Step 4. Evaluate impacts and document the results.

Factor 4 is also addressed in the step-wise review of the emission reduction options, primarily in the context of the cost of emission reduction options and whether any capitalization of expenses would be impacted by limited equipment life. Once the step-wise review of control options was completed, a review of the timing of the emission reductions was done to satisfy Factor 2 of the four factors.

A review of the four factors for NO_X and limited review for SO_2 can be found in Sections 5 and 6 of this report, respectively. Section 4 of this report includes information on the Talen Colstrip Units 1 – 4 existing/baseline emissions.

---

[4] The BART provisions were published as amendments to the EPA's RHR in 40 CFR 51.308 on July 5, 2005.

[5]References to BART and BART requirements in this Analysis should not be construed as an indication that BART is applicable to the Talen Colstrip Facility Units 3 and 4.

The Talen Colstrip Power Plant is located in Rosebud County near Colstrip, Montana. The nearest mandatory Class I area to the plant is the UL Bend National Wildlife Refuge, approximately 200 kilometers (km) northwest of the Colstrip Power Plant. In addition, four other mandatory Class I areas are within 300 km of the Colstrip Power plant: the North Absaroka Wilderness (254 km to the west), the Theodore Roosevelt National Park (260 km to the northeast), the Washakie Wilderness (278 km to the southwest), and Yellowstone National Park (281 km to the west).

The facility operates four (4) tangential coal-fired boilers. Each boiler operates with a wet venturi scrubber, low NO_X burner firing system and digital controls, and Units 2, 3, and 4 operate Smartburn® low NO_X combustion systems.

Units 1 and 2 commenced operations in 1975 and 1976, respectively. Units 3 and 4 commenced operations in 1984 and 1986, respectively and were subject to PSD permitting and SO_2 and NO_X BACT.

Units 1 and 2 were subject to review under the BART program, and all four units completed review under Reasonable Progress for the Regional Haze Program. Under the RHR, Unit 2 has installed Smartburn® technology. Talen has completed additional projects outside of the regional haze program, such as adding Smartburn® technology on Units 3 and 4 to reduce NO_X emissions.

Since Units 1 and 2 are required to shut down by July 1, 2022, per Title V Operating Permit OP0513-14, Permit Condition B.4.d and Montana Board of Environmental Review Board Order, the baseline emissions are considered in Section 4 in the discussion of emission reductions at the facility, but the units are not considered further in the four factor analysis given that any requirement to install controls likely would not be effective until after the units' shutdown date.[6] Only Units 3 and 4 are considered in the four factor analysis.

---

[6] Under 40 CFR 51.308(f), states must submit their second planning period regional haze SIPs to EPA by July 31, 2021, and Section 110 of the Clean Air Act grants EPA one year to take action on the SIP submittal. Therefore, unless DEQ were to submit its SIP early to EPA, any requirements for Colstrip Units 1 and 2 would not become effective until at least July 31, 2022. *See also* US EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* (August 20, 2019) (explaining that states may exclude sources from the four factor analysis if they will shut down by the end of the second planning period).

This section summarizes emission rates that were used as baseline rates in the four factor analyses presented in Sections 5 and 6 of this report.

Baseline annual emissions for NO_X and SO_2 were calculated based on annual reported data to DEQ derived from continuous emission monitoring system (CEMS) data. The baseline annual emission rates are summarized in Table 4-1, Table 4-2, Table 4-3, and Table 4-4.

Table 4-1. NO_X Annual Baseline Emission Rates

Unit/Year	2014 (ton/yr)	2015 (ton/yr)	2016 (ton/yr)	2017 (ton/yr)	2018 (ton/yr)	2016 – 2018 Average (ton/yr)
Unit 1	3,834	3,717	3,308	3,084	3,412	3,268
Unit 2	3,788	2,090	1,691	1,830	1,557	1,693
Unit 3	3,679	4,611	4,241	3,402	3,815	3,820
Unit 4	4,286	4,725	3,509	4,077	3,780	3,789

Units 1 and 2 are required to shut down by July 1, 2022, and will result in 4,961 tpy[7] reduction of NO_X from these units. This represents 39% of the Colstrip facility's NO_X emissions.

Smartburn® technology was installed on Unit 3 in late 2017, so 2018 is the only full year with the technology implemented and representative of current emissions. Smartburn® technology was installed on Unit 4 in late 2016, so 2017-2018 is representative of the current actual emissions for the unit.

Annual heat input rates (MMBtu/yr) and corresponding NO_X emission rates (lb/MMBtu) using representative data years are provided below in Table 4-2. The current permitted NO_X emission rate for Units 3 and 4 is 0.18 lb/MMBtu (30-day rolling average) when the unit is operating at > 400 MW, and 0.3 lb/MMBtu (30-day rolling average) if the unit is operating at ≤ 400 MW (30-day rolling average).

Table 4-2. Calculated Unit 3 and Unit 4 Baseline NO_X Emission Rates

Unit	Parameter	2017	2018	Baseline Value
Unit 3	Heat Input Generation (MMBtu/yr)	--	52,438,449	52,438,449
	NO_X Rate (lb/MMBtu)	--	0.15	0.15
Unit 4	Heat Input Generation (MMBtu/yr)	55,952,971	49,078,872	52,515,921
	NO_X Rate (lb/MMBtu)	0.15	0.15	0.15

---

[7] Based on NO_X 2016-2018 annual average for both the Units 1 and 2 total emissions.

Table 4-3. SO$_2$ Annual Baseline Emission Rates

Unit/Year	2014 (ton/yr)	2015 (ton/yr)	2016 (ton/yr)	2017 (ton/yr)	2018 (ton/yr)	2016-2018 Average (ton/yr)
Unit 1	2,423	2,013	1,631	1,731	1,777	1,731
Unit 2	3,401	1,745	1,907	2,397	1,789	2,031
Unit 3	1,994	2,543	2,434	2,052	2,133	2,206
Unit 4	2,292	2,623	2,086	2,310	1,959	2,118

Units 1 and 2 are required to shut down by July 1, 2022, and will result in an average of 3,762 tpy[8] reduction of SO$_2$ from these units. This represents approximately 47% of the facility's SO$_2$ emissions.

Of the multiple SO$_2$ limits applicable to Units 3 and 4, the most stringent is 761 lb/hour which is equivalent to 0.10 lb/MMBtu, 30-day rolling average[9]. The SO$_2$ emissions monthly average across the 2016-2018 baseline period is 0.08 lb/MMBtu for both units as shown in Table 4-4.

Table 4-4. Calculated Unit 3 and Unit 4 Baseline SO$_2$ Emission Rates

Unit	Parameter	2016	2017	2018	(2016-2018) Baseline Value
Unit 3	Heat Input Generation (MMBtu/yr)	54,667,327	48,710,426	52,438,449	51,938,734
	SO$_2$ Rate (lb/MMBtu)	0.09	0.08	0.08	0.08
Unit 4	Heat Input Generation (MMBtu/yr)	50,278,162	55,952,971	49,078,872	51,770,002
	SO$_2$ Rate (lb/MMBtu)	0.08	0.08	0.08	0.08

By 2028, the end of the 2nd implementation period, Colstrip Units 1 and 2 will have zero emissions. Units 3 and 4 projected NO$_X$ emissions are expected to remain similar to the 2016-2018 average due to the recent installation of Smartburn® technology. SO$_2$ emission rates are expected to remain steady; however, 2018 had a lower

---

[8] Based on SO$_2$ 2016-2018 annual average for both the Units 1 and 2 total emissions.

[9] Colstrip Units 3 and 4 are also required to meet the SO$_2$ emissions limit of 0.2 lb/MMBtu per 40 CFR Part 63, Subpart UUUUU – National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, also known as the Mercury Air Toxics Standards (MATS). This limit is noted in US EPA's *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period* from August 20, 2019, stating that it may be reasonable for a state not to select an effectively controlled source, such as an EGU that has add-on flue gas desulfurization (FGD) and that meets the applicable alternative SO$_2$ emission limit of the 2012 Mercury Air Toxics Standards (MATS) rule for power plants (0.2 lb/MMBtu for coal-fired EGUs). "[The] limits are low enough that it is unlikely that an analysis of control measures for a source already equipped with a scrubber and meeting one of these limits would conclude that even more stringent control of SO$_2$ is necessary to make reasonable progress."

capacity factor than other years so the projected SO_2 emission rates are expected to be more similar to the 2015-2017 average emission rate based on current emission controls. Projected 2028 emissions for Units 1-2 and 3-4 are provided in Table 4-5.

Table 4-5. NO_X and SO_2 2028 Projected Emission Rates

Unit	2028 Projected NO_X (tpy)	2028 Projected SO_2 (tpy)
Unit 1	0	0
Unit 2		
Unit 3	7,700	4,700
Unit 4		

As described in Section 2, Factors 1 and 3 of the four factor analysis were considered by conducting a step-wise review of emission reduction options in a top-down fashion. The steps are as follows:

Step 1. Identify all available retrofit control technologies
Step 2. Eliminate technically infeasible control technologies
Step 3. Evaluate the control effectiveness of remaining control technologies
Step 4. Evaluate impacts and document the results

Factor 4 is also addressed in the step-wise review of the emission reduction options, primarily in the context of the cost of emission reduction options. This section presents the step-wise review of control options for NO$_X$. Following the step-wise review of the control options for NO$_X$ is a review of the timing of the emission reductions to satisfy Factor 2 of the four factors.

The baseline NO$_X$ emission rates that were used in the NO$_X$ four factor analysis are summarized in Table 4-3. The basis of the emission rates is provided in Section 4 of this report. Units 3 and 4 are each currently equipped with digital boiler controls, low NO$_X$ burners (LNB), Separated Over-Fire Air (SOFA), and Smartburn® low NO$_X$ combustion systems. Talen most recently implemented Smartburn® technology on Unit 3 in the fourth quarter of 2017, and on Unit 4 in the fourth quarter of 2016, to further reduce NO$_X$ emissions.

5.1. STEP 1: IDENTIFICATION OF AVAILABLE NO$_X$ CONTROL TECHNOLOGIES

In combustion processes, NO$_X$ is formed by three different mechanisms: fuel NO$_X$, thermal NO$_X$ and prompt NO$_X$.

"Fuel NO$_X$" forms when fuels containing nitrogen (such as coal) are burned. Oxidation of the already-ionized nitrogen in the fuel results in fuel NO$_X$.

"Thermal NO$_X$" is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and react to form NO$_X$ at high combustion temperatures.

"Prompt NO$_X$" forms in fuel-rich environments, in a fast reaction involving nitrogen, oxygen and hydrocarbon radicals.

Step 1 of the top-down control review is to identify available control options for NO$_X$.

NO$_X$ emissions controls can be categorized as combustion or post-combustion controls. The controls currently installed on Units 3 and 4 are combustion controls, which minimizes NO$_X$ formation. Post-combustion controls, such as SCR and SNCR, convert NO$_X$ in the flue gas to molecular nitrogen and water. These controls are not currently installed on Units 3 and 4, and are therefore identified as potential add-on NO$_X$ control options. The RBLC search results[10] showing SCR and SNCR (in addition to the combustion controls that are already installed on Units 3 and 4) as the available controls are included in Appendix B.

---

[10] Note that the RBLC search goes back 15 years for coal-fired boilers > 250 MMBtu/hr. No facilities were removed from the RBLC search result, including facilities that are listed in the RBLC database, but were not built.

5.1.1. Selective Non-Catalytic Reduction

In SNCR systems, a reagent is injected into the combustion zone of the boiler where the temperature is in a range of 1600 °F to 2000 °F. The NO_X and reagent (ammonia or urea) react to form atmospheric nitrogen and water (and carbon dioxide if urea serves as the source of ammonia).

In coal-fired boilers without any existing controls, NO_X reduction resulting from SNCR installation can range from 38 – 83% if ammonia is used as the reagent, and 20 – 66% if urea is the reagent.[11] As indicated in Section 4, baseline emissions for Units 3 and 4 are 0.15 lb NO_X/MMBtu, which is approximately a 63% reduction when compared to the boiler emissions prior to combustion controls (LNB and SOFA).[12] Based on a similar analysis performed recently for Entergy's White Bluff Units 1 and 2, for a unit that would achieve a NO_X rate of 0.15 lb/MMBtu with LNB and SOFA only, the expected controlled NO_X emission rate when SNCR is combined with LNB and SOFA is 0.13 lb/MMBtu.[13] This represents a 13% control of NO_X emissions as compared to current NO_X emissions.

Often times, in order to overcome inherent natural system limitations of a SNCR system and achieve the desired level of NO_X reduction, it is necessary to inject excess reagent.[14] This results in what is referred to as "ammonia slip". In sulfur-containing fuel, this unreacted ammonia can result in the formation of ammonium bisulfate and ammonium sulfate. These ammonia-sulfur salts can plug, foul, and corrode downstream equipment such as air heaters, ducts, and fans, which requires additional equipment maintenance, and the facility would likely see an increase in forced outages.

5.1.2. Selective Catalytic Reduction

Similarly, SCR is an exhaust gas treatment process in which reagent (ammonia or urea) is injected into the exhaust gas. However, in SCR, the reagent is injected upstream of a catalyst bed, which allows the reaction to occur at lower temperatures. On the catalyst surface, ammonia and nitric oxide (NO) or nitrogen dioxide (NO_2) react to form diatomic nitrogen and water.

Outlet NO_X concentrations from SCR on a utility boiler are rarely less than 0.04 lb/MMBtu.[15] Consistent with the analysis conducted for Units 3 and 4 in 2011, the lowest NO_X emission rate attainable at either Unit 3 or 4 is expected to be 0.06 lb/MMBtu, and this would likely only be achievable for higher load operations. This represents a 60% control of NO_X emissions as compared to current NO_X emissions.

While ammonia slip from SCR is expected to be lower than with SNCR, similar downstream fouling may still occur.

---

[11] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NO_X Controls, EPA/452/B-02-001.

[12] Per the analysis conducted in 2011, baseline emissions for the boilers prior to combustion controls were 0.4 lb/MMBtu.

[13] Federal Register 2015, 80 FR 18943 Promulgation of Air Quality Implementation Plans; State of Arkansas; Regional Haze and Interstate Visibility Transport Federal Implementation Plan.

[14] Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NO_X Controls, EPA/452/B-02-001.

[15] Ibid.

5.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE NO$_X$ CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible NO$_X$ control technologies that were identified in Step 1. Despite known potential for fouling caused by ammonia slip, both SCR and SNCR have been demonstrated at numerous coal-fired power plants in the United States. As such, these control technologies are considered technically feasible, and a cost analysis is conducted in Section 5.4.

5.3. STEP 3: RANK OF TECHNICALLY FEASIBLE NO$_X$ CONTROL OPTIONS BY EFFECTIVENESS

Step 3 of the top-down control review is to rank the technically feasible options by effectiveness. Table 5-1 presents potential NO$_X$ control technologies for the boilers and their associated controlled emission rates.

Table 5-1. Ranking of NO$_X$ Control Technologies by Effectiveness

Pollutant	Control Technology	Controlled Emission Rate
NO$_x$	SCR + LNB and SOFA	0.06 lb/MMBtu
	SNCR + LNB and SOFA	0.13 lb/MMBtu
	LNB and SOFA	0.15 lb/MMBtu (Base case)

5.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE NO$_X$ CONTROLS

Step 4 of the top-down control review is the impact analysis. The impact analysis considers the:

> Cost of compliance
> Energy impacts
> Non-air quality impacts; and
> The remaining useful life of the source

5.4.1. Cost of Compliance

In order to assess the cost of compliance for the installation of SCR and SNCR, the EPA Control Cost Manual was used. The EPA cost spreadsheets were released in June 2019 and include updates to the equations and calculation approach from prior EPA analyses for coal-fired boilers evaluating the cost effectiveness for SNCR and SCR add-on controls. Consistent with Control Cost Manual recommendations, capital costs for the installation of the SNCR assumed a 20-year life span for depreciation and capital costs for the installation of the SCR assumed a 30-year life span. The current bank prime rate of 5.5% was used for interest calculations, as determined using the Federal Reserve's Selected Interest Rates table.[16] The total capital investment includes the capital cost for the control technology itself, reagent preparation costs, and the balance of the plant (i.e., supporting components and auxiliary systems) costs. Annual costs include both direct costs such as maintenance, reagent, electricity, water, fuel, and waste disposal cost, as well as indirect costs for administrative charges and the annuitized capital costs as a capital recovery value. The total costs and cost effectiveness of control in 2018 dollars for each Unit are summarized in Table 5-2, below. Note that Colstrip Units 3 and 4 NO$_X$ inlet rates have decreased from 0.168 lb/MMBtu as evaluated in the 2011 reasonable progress analysis to 0.15

---

[16] Federal Reserve, H.15 Selected Interest Rates (Daily). https://www.federalreserve.gov/releases/h15/, accessed on July 31, 2019.

lb/MMBtu (based on average of 2016-2018) used in this analysis. The decrease in inlet emissions and changes to the EPA cost spreadsheets have increased the cost per ton of the add-on controls in this updated analysis.

Table 5-2. SNCR Cost Calculation Summary Per Unit

	SCR	SNCR
Capital Cost	$310,946,279	$17,750,899
Direct Annual Costs	$6,347,422	$2,937,728
Indirect Annual Costs	$21,414,389	$1,493,738
Total Annual Costs	$27,761,811	$4,431,466
NO_X in (lb/MMBtu)	0.15	0.15
NO_X out (lb/MMBtu)	0.06	0.13
NO_X Reduction (tons)	2,159	433
Cost Effectiveness ($/ton)	$12,858	$10,234

The full cost analysis performed using U.S. EPA's Air Pollution Control Cost Manual spreadsheet[17] is provided in Appendix A. Where site-specific data was not available, default values provided in the Control Cost Manual were used.

The equations used in the Control Cost Manual include a "retrofit factor" to account for retrofits that are expected to be more or less complicated than average. The installation of SCR and SNCR systems requires a significant footprint due to the need for reagent preparation equipment and reagent receipt and unloading operations. Space at the Colstrip facility is already limited by the presence of the particulate matter and SO_2 scrubbers. As such, Talen has used a retrofit factor of 1.3, rather than the 1.0 that would characterize a more open site plan than that available at Colstrip. This retrofit factor is in alignment with past Reasonable Progress control analyses for SCR add-on control.

5.4.2. Energy Impacts and Non-Air Quality Impacts

As previously stated, the cost of energy and water required for successful operation of the SCR or SNCR are included in the calculations, which can be found in detail in Appendix A.

Ammonia slip from the SCR or SNCR can also impact plume visibility.

5.4.3. Remaining Useful Life

Talen has assumed this control equipment will last for the entirety of the 20-year (SNCR) and 30-year (SCR) amortization period, which is reflected in the cost calculations. While these assumptions are used for conservatism as the default in EPA's cost control spreadsheets, it is uncertain that the Units would operate this long. A shorter equipment lifetime would further increase the estimated cost per ton of NO_X removed.

---

[17] Air Pollution Control Cost Estimation Spreadsheet. US EPA, Air Economics Group, Health and Environmental Impacts Division, Office of Air Quality Planning and Standards, June 2019.

5.5. NO$_X$ REVIEW

Units 3 and 4 are each currently equipped with digital boiler controls, low NO$_X$ burners (LNB), Separated Over-Fire Air (SOFA), and Smartburn® low NO$_X$ combustion systems. The addition of SCR or SNCR controls would not represent a cost effective control technology given the limited expected improvements to NO$_X$ emission rates, high capital investment, and high cost per ton NO$_X$ removed. Furthermore, anticipated fouling caused by ammonia slip could cause an increase in forced maintenance outages (unit downtime) and related maintenance costs, which are not accounted for in the cost analysis.

5.6. TIMING FOR COMPLIANCE

For purposes of completing the cost analysis, 2018 dollars (most recent full year of available cost data) were used, and an assumption that if additional controls were required that they could be installed during the second period of the regional haze program.

5.7. NO$_X$ CONCLUSION

The shutdown of Units 1 and 2 will result in 4,961 tpy reduction of NO$_X$ from these units. This represents 39% of the Colstrip facility's NOx emissions. Units 3 and 4 employ all cost effective NO$_X$ controls for the regional haze program, and no additional controls could be cost effectively installed at the Colstrip Power Plant.

For SO$_2$, an abbreviated four factor analysis was considered. SO$_2$ is generated during coal combustion from the oxidation of sulfur contained in the fuel. SO$_2$ emissions are dependent on the sulfur content of the fuel and are generally not affected by boiler size or burner design. Units 3 and 4 use low sulfur coal and wet scrubbers with lime injection to reduce SO$_2$ emissions to low levels. As such, Talen believes that no further controls for reasonable progress purposes are necessary.

6.1. SO$_2$ CONTROL TECHNOLOGIES

Talen's air permit[18] limits sulfur content of coal to 1% (as received), and the most stringent SO$_2$ emission limit of 761 lb/hr (equivalent to 0.10 lb SO$_2$/MMBtu), 30-day rolling average. From 2016-2018, Units 3 and 4 annual average sulfur content was 0.7% (as received), and SO$_2$ emission rates were 0.08 lb SO$_2$/MMBtu (monthly average). The Colstrip boilers are equipped with CEMS for SO$_2$, which were used to determine baseline emission rates. The baseline SO$_2$ emission rates are also summarized in Table 4-1.

In addition to using low sulfur coal, Units 3 and 4 use eight (8) wet venturi scrubbers per unit to reduce SO$_2$ and meet their permit limits. Per the Units 3 and 4 PSD permit[19] the SO$_2$ control systems are a two-staged venturi scrubber/spray tower absorbers module, utilizing the lime addition and the alkalinity of the collected fly ash for SO$_2$ removal. The scrubbing system includes the past use of hydrated dolomitic lime (containing a mixture of calcium and magnesium hydroxides) and current use of calcium-only lime as the scrubbing reagent. The scrubber system was designed and certified in its Montana Facility Siting Certificate to achieve 95% control. Colstrip Units 3 and 4 have maintained compliance with the SO$_2$ emission standards with the low sulfur coal and use of the scrubber system.

It is important to note that in addition to SO$_2$ controls noted above, Talen has no provisions for scrubber bypass, and Talen has a spare scrubber vessel per unit available for service. These best management practices ensure the SO$_2$ controls are maintained and operating at all times. Furthermore, per the 2011 analysis and still valid, no enhancement techniques/improvements to the current scrubbers are available for Units 3 and 4 because they are already incorporated into the current design, or have been shown to not be effective on scrubbers of this type. Such additional technologies include Elimination of Bypass Reheat (incorporated), Installation of Liquid Distribution Rings (incorporated), Installation of Perforated Trays (incorporated), Use of Organic Acid Additives (ineffective), Improve or Upgrade Scrubber Auxiliary System Equipment (incorporated) and Redesign Spray Header or Nozzle Configuration (ineffective).

With the current design of Colstrip Units 3 and 4 tangential coal-fired boilers, all known SO$_2$ add-on controls are being used, as shown in Appendix C – SO$_2$ RBLC search results[20]. Controls or fuel switching which would change the nature or design of the boilers were not considered in this analysis.

---

[18] Title V Operating Permit Reference OP0513-14 Conditions C.

[19] Units 3 and 4 PSD Permit - BACT Evaluation for SO2 and Particulate Controls for Colstrip Units 3 and 4 Prepared by PEDCo Environmental, Inc. for EPA Region VIII, May 1979.

[20] Note that the RBLC search goes back 15 years for coal-fired boilers > 250 MMBtu/hr. No facilities were removed from the RBLC search result, including facilities that are listed in the RBLC database, but were not built.

6.2. SO₂ CONCLUSION

During the 2016-2018 baseline period, Colstrip Units 3 and 4 achieved a low SO_2 emission rate in alignment with their current permit limit of 761 lb/hr (equivalent to 0.10 lb/MMBtu rolling 30-day average) and complied with the 2012 MATS SO_2 emissions limit of 0.20 lb/MMBtu. Based on the current high level of demonstrated and design control capability, further SO_2 reductions are not reasonably available for Colstrip Units 3 and 4.

Colstrip Units 1 and 2 will be shut down by July 1, 2022 and will result in a reduction of 3,762 tpy of SO_2, which is approximately 47% of the Colstrip facility's SO_2 annual average emissions. Talen does not anticipate any further SO_2 reductions from the Colstrip Power Plant should be required for the second planning period.

SNCR Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler?　　[Utility ▼]

What type of fuel does the unit burn?　　[Coal ▼]

Is the SNCR for a new boiler or retrofit of an existing boiler?　　[Retrofit ▼]

Please enter a retrofit factor equal to or greater than 0.84 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.　　[1.3]　　* NOTE: You must document why a retrofit factor of 1.3 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)?	805 MW
What is the higher heating value (HHV) of the fuel?	8,451 Btu/lb
What is the estimated actual annual MWh output?	5,262,954 MWh
Is the boiler a fluid-bed boiler?	No
Enter the net plant heat input rate (NPHR)	9.371 MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Provide the following information for coal-fired boilers:

Type of coal burned:　　[Sub-Bituminous ▼]

Enter the sulfur content (%S) =　　0.95 percent by weight

or

Select the appropriate SO_2 emission rate:　　[Not Applicable ▼]

Ash content (%Ash):　　10.17 percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV, %S, %Ash and cost. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

	Fraction in Coal Blend	%S	%Ash	HHV (Btu/lb)	Fuel Cost ($/MMBtu)
Bituminous	0	1.84	9.23	11,841	2.4
Sub-Bituminous	0	0.41	5.84	8,826	1.89
Lignite	0	0.82	13.6	6,626	1.74

Please click the calculate button to calculate weighted values based on the data in the table above.

Enter the following design parameters for the proposed SNCR:

Number of days the SNCR operates (t_{SNCR})	365	days
Inlet NO_x Emissions (NOx_{in}) to SNCR	0.15	lb/MMBtu
Oulet NO_x Emissions (NOx_{out}) from SNCR	0.13	lb/MMBtu
Estimated Normalized Stoichiometric Ratio (NSR)	0.803	

Plant Elevation	3250 Feet above sea level

0.63110004

*The NSR for a urea system may be calculated using equation 1.17 in Section 4, Chapter 1 of the Air Pollution Control Cost Manual (as updated March 2019).

Concentration of reagent as stored (C_{stored})	50	Percent
Density of reagent as stored (ρ_{stored})	71	lb/ft^3
Concentration of reagent injected (C_{inj})	50	percent
Number of days reagent is stored ($t_{storage}$)	14	days
Estimated equipment life	20	Years

Densities of typical SNCR reagents:	
50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Select the reagent used	Urea ▼

Enter the cost data for the proposed SNCR:

Desired dollar-year	2018	
CEPCI for 2018	603.1 Enter the CEPCI value for 2018	541.7 2016 CEPCI

CEPCI = Chemical Engineering Plant Cost Index

* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)

Annual Interest Rate (i)	5.5	Percent*
Fuel ($Cost_{fuel}$)	1.89	$/MMBtu*
Reagent ($Cost_{reag}$)	1.66	$/gallon for a 50 percent solution of urea*
Water ($Cost_{water}$)	0.0042	$/gallon*
Electricity ($Cost_{elect}$)	0.0361	$/kWh*
Ash Disposal (for coal-fired boilers only) ($Cost_{ash}$)	48.80	$/ton*

* The values marked are default values. See the table below for the default values used and their references. Enter actual values, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.015
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon of 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6, Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SNCR Cost Development Methodology, Chapter 5, Attachment 5-4, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-4_sncr_cost_development_methodology.pdf.	
Water Cost ($/gallon)	0.00417	Average water rates for industrial facilities in 2013 compiled by Black & Veatch. (see 2012/2013 "50 Largest Cities Water/Wastewater Rate Survey." Available at http://www.saws.org/who_we_are/community/RAC/docs/2014/50-largest-cities-brochure-water-wastewater-rate-survey.pdf.	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Fuel Cost ($/MMBtu)	1.89	U.S. Energy Information Administration. Electric Power Annual 2016. Table 7.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Ash Disposal Cost ($/ton)	48.8	Waste Business Journal. The Cost to Landfill MSW Continues to Rise Despite Soft Demand. July 11, 2017. Available at: http://www.wastebusinessjournal.com/news/wbj20170711A.htm.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Percent ash content for Coal (% weight)	5.84	Average ash content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Interest Rate (%)	5.5	Default bank prime rate	

SNCR Design Parameters

The following design parameters for the SNCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	7,544	MMBtu/hour
Maximum Annual MWh Output =	Bmw x 8760 =	7,051,800	MWh
Estimated Actual Annual MWh Output (Boutput) =		5,262,954	MWh
Heat Rate Factor (HRF) =	NPHR/10 =	0.94	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tsncr/365) =	0.75	fraction
Total operating time for the SNCR (t_{op}) =	CF_{total} x 8760 =	6538	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	12	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	132.47	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	433.02	tons/year
Coal Factor ($Coal_F$) =	1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*(1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.13	
Atmospheric pressure at 3250 feet above sea level (P) =	$2116 \times [(59-(0.00356 \times h)+459.7)/518.6]^{5.256} \times (1/144)$* =	13.1	psia
Retrofit Factor (RF) =	Retrofit to existing boiler	1.30	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Reagent Data:

Type of reagent used	Urea		Molecular Weight of Reagent (MW) =	60.06 g/mole
			Density =	71 lb/gallon

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	$(NOx_{in} \times Q_B \times NSR \times MW_R)/(MW_{NOx} \times SR) =$ (whre SR = 1 for NH_3; 2 for Urea)	583	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}/C_{sol} =$	1,166	lb/hour
	$(m_{sol} \times 7.4805)/$Reagent Density =	122.9	gal/hour
Estimated tank volume for reagent storage =	$(m_{sol} \times 7.4805 \times t_{storage} \times 24$ hours/day$)/$Reagent Density =	41,300	gallons (storage needed to store a 14 day reagent supply rounded up to the nearest 100 gallons)

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	$i (1+ i)^n/(1+ i)^n - 1 =$ Where n = Equipment Life and i= Interest Rate	0.0837

Parameter	Equation	Calculated Value	Units
Electricity Usage: Electricity Consumption (P) =	$(0.47 \times NOx_{in} \times NSR \times Q_B)/NPHR =$	44.8	kW/hour
Water Usage: Water consumption (q_w) =	$(m_{sol}/$Density of water$) \times ((C_{stored}/C_{inj}) - 1) =$	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	$Hv \times m_{reagent} \times ((1/C_{inj})-1) =$	0.52	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	$(\Delta fuel \times \%Ash \times 1 \times 10^6)/HHV =$	6.3	lb/hour

SNCR Cost Estimate

Total Capital Investment (TCI)

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + APH_{cost} + BOP_{cost})$$

For Fuel Oil and Natural Gas-Fired Boilers:

$$TCI = 1.3 \times (SNCR_{cost} + BOP_{cost})$$

Capital costs for the SNCR (SNCR$_{cost}$) =	$6,081,168 in 2018 dollars
Air Pre-Heater Costs (APH$_{cost}$)* =	$0 in 2018 dollars
Balance of Plant Costs (BOP$_{cost}$) =	$7,573,370 in 2018 dollars
Total Capital Investment (TCI) =	$17,750,899 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

SNCR Capital Costs (SNCR$_{cost}$)

For Coal-Fired Utility Boilers:

$$SNCR_{cost} = 220,000 \times (B_{MW} \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$SNCR_{cost} = 147,000 \times (B_{MW} \times HRF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers:

$$SNCR_{cost} = 220,000 \times (0.1 \times Q_B \times HRF)^{0.42} \times CoalF \times BTF \times ELEVF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$SNCR_{cost} = 147,000 \times ((Q_B/NPHR) \times HRF)^{0.42} \times ELEVF \times RF$$

SNCR Capital Costs (SNCR$_{cost}$) =	$6,081,168 in 2018 dollars

Air Pre-Heater Costs (APH$_{cost}$)*

For Coal-Fired Utility Boilers:

$$APH_{cost} = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers:

$$APH_{cost} = 69,000 \times (0.1 \times Q_B \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH$_{cost}$) =	$0 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BOP$_{cost}$)

For Coal-Fired Utility Boilers:

$$BOP_{cost} = 320,000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Utility Boilers:

$$BOP_{cost} = 213,000 \times (B_{MW})^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

For Coal-Fired Industrial Boilers:

$$BOP_{cost} = 320,000 \times (0.1 \times Q_B)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times BTF \times RF$$

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

$$BOP_{cost} = 213,000 \times (Q_B/NPHR)^{0.33} \times (NO_xRemoved/hr)^{0.12} \times RF$$

Balance of Plant Costs (BOP$_{cost}$) =	$7,573,370 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$2,937,728 in 2018 dollars
Indirect Annual Costs (IDAC) =	$1,493,738 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$4,431,466 in 2018 dollars

Direct Annual Costs (DAC)
DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Water Cost) + (Annual Fuel Cost) + (Annual Ash Cost)

Annual Maintenance Cost =	$0.015 \times TCI$ =	$266,263 in 2018 dollars
Annual Reagent Cost =	$q_{sol} \times Cost_{reag} \times t_{op}$ =	$1,333,398 in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op}$ =	$10,575 in 2018 dollars
Annual Water Cost =	$q_{water} \times Cost_{water} \times t_{op}$ =	$0 in 2018 dollars
Additional Fuel Cost =	$\Delta Fuel \times Cost_{fuel} \times t_{op}$ =	$6,484 in 2018 dollars
Additional Ash Cost =	$\Delta Ash \times Cost_{ash} \times t_{op} \times (1/2000)$ =	$1,007 in 2018 dollars
Maintenance Cleanings* =	$4 \times \$330,000$ =	$1,320,000 in 2018 dollars
Direct Annual Cost =		$2,937,728 in 2018 dollars

* Consistent with the 2011 analysis, direct annual costs will include four cleanings per year at $330,000 each. These cleanings are necessary due to fouling of the air preheater caused by SNCR technology.

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	$0.03 \times$ Annual Maintenance Cost =	$7,988 in 2018 dollars
Capital Recovery Costs (CR)=	$CRF \times TCI$ =	$1,485,750 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$1,493,738 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$4,431,466 per year in 2018 dollars
NOx Removed =	433 tons/year
Cost Effectiveness =	$10,234 per ton of NOx removed in 2018 dollars

SCR Data Inputs

Enter the following data for your combustion unit:

Is the combustion unit a utility or industrial boiler? **Utility ▼**

Is the SCR for a new boiler or retrofit of an existing boiler? **Retrofit ▼**

What type of fuel does the unit burn? **Coal ▼**

Please enter a retrofit factor between 0.8 and 1.5 based on the level of difficulty. Enter 1 for projects of average retrofit difficulty.

1.3

* NOTE: You must document why a retrofit factor of 1.3 is appropriate for the proposed project.

Complete all of the highlighted data fields:

What is the MW rating at full load capacity (Bmw)? | **805** MW

What is the higher heating value (HHV) of the fuel? | **8,451** Btu/lb

What is the estimated actual annual MWhs output? | **5,262,954** MWhs

Enter the net plant heat input rate (NPHR) | **9.371** MMBtu/MW

If the NPHR is not known, use the default NPHR value:

Fuel Type	Default NPHR
Coal	10 MMBtu/MW
Fuel Oil	11 MMBtu/MW
Natural Gas	8.2 MMBtu/MW

Plant Elevation | **3250** Feet above sea level

Provide the following information for coal-fired boilers:

Type of coal burned: **Sub-Bituminous ▼**

Enter the sulfur content (%S) = **0.95** percent by weight

For units burning coal blends:

Note: The table below is pre-populated with default values for HHV and %S. Please enter the actual values for these parameters in the table below. If the actual value for any parameter is not known, you may use the default values provided.

Coal Type	Fraction in Coal Blend	%S	HHV (Btu/lb)
Bituminous	0	1.84	11,841
Sub-Bituminous	0	0.41	8,826
Lignite	0	0.82	6,685

Please click the calculate button to calculate weighted average values based on the data in the table above.

For coal-fired boilers, you may use either Method 1 or Method 2 to calculate the catalyst replacement cost. The equations for both methods are shown on rows 85 and 86 on the *Cost Estimate* tab. Please select your preferred method:

○ Method 1
◉ Method 2
○ Not applicable

Enter the following design parameters for the proposed SCR:

Number of days the SCR operates (t_{SCR}) — 365 days

Number of days the boiler operates (t_{plant}) — 365 days

Inlet NO_x Emissions (NOx_{in}) to SCR — 0.15 lb/MMBtu

Outlet NO_x Emissions (NOx_{out}) from SCR — 0.06 lb/MMBtu

Stoichiometric Ratio Factor (SRF) — 0.525

*The SRF value of 0.525 is a default value. User should enter actual value, if known.

Estimated operating life of the catalyst ($H_{catalyst}$) — 24,000 hours

Estimated SCR equipment life — 30 Years*

* For utility boilers, the typical equipment life of an SCR is at least 30 years.

Concentration of reagent as stored (C_{stored}) — 50 percent*

Density of reagent as stored (ρ_{stored}) — 71 lb/cubic feet*

Number of days reagent is stored ($t_{storage}$) — 14 days

Select the reagent used — Urea

Number of SCR reactor chambers (n_{scr}) — 1

Number of catalyst layers (R_{layer}) — 3

Number of empty catalyst layers (R_{empty}) — 1

Ammonia Slip (Slip) provided by vendor — 2 ppm

Volume of the catalyst layers ($Vol_{catalyst}$)
(Enter "UNK" if value is not known) — UNK Cubic feet

Flue gas flow rate ($Q_{fluegas}$)
(Enter "UNK" if value is not known) — UNK acfm

Gas temperature at the SCR inlet (T) — 650 °F

Base case fuel gas volumetric flow rate factor (Q_{fuel}) — 516 ft^3/min-MMBtu/hour

*The reagent concentration of 50% and density of 71 lbs/cft are default values for urea reagent. User should enter actual values for reagent, if different from the default values provided.

Densities of typical SCR reagents:

50% urea solution	71 lbs/ft^3
29.4% aqueous NH_3	56 lbs/ft^3

Enter the cost data for the proposed SCR:

Desired dollar-year	2018		
CEPCI for 2018	603.1 Enter the CEPCI value for 2018	541.7 2016 CEPCI	CEPCI = Chemical Engineering Plant Cost Index
Annual Interest Rate (i)	5.5 Percent*		* 5.5 percent is the default bank prime rate. User should enter current bank prime rate (available at https://www.federalreserve.gov/releases/h15/.)
Reagent (Cost$_{reag}$)	2.136 $/gallon for 50% urea		
Electricity (Cost$_{elect}$)	0.0361 $/kWh		* $0.0361/kWh is a default value for electicity cost. User should enter actual value, if known.
Catalyst cost (CC $_{replace}$)	227.00 $/cubic foot (includes removal and disposal/regeneration of existing catalyst and installation of new catalyst		* $227/cf is a default value for the catalyst cost based on 2016 prices. User should enter actual value, if known.
Operator Labor Rate	60.00 $/hour (including benefits)*		* $60/hour is a default value for the operator labor rate. User should enter actual value, if known.
Operator Hours/Day	4.00 hours/day*		* 4 hours/day is a default value for the operator labor. User should enter actual value, if known.

Note: The use of CEPCI in this spreadsheet is not an endorsement of the index, but is there merely to allow for availability of a well-known cost index to spreadsheet users. Use of other well-known cost indexes (e.g., M&S) is acceptable.

Maintenance and Administrative Charges Cost Factors:

Maintenance Cost Factor (MCF) =	0.005
Administrative Charges Factor (ACF) =	0.03

Data Sources for Default Values Used in Calculations:

Data Element	Default Value	Sources for Default Value	If you used your own site-specific values, please enter the value used and the reference source . . .
Reagent Cost ($/gallon)	$1.66/gallon 50% urea solution	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model, Updates to the Cost and Performance for APC Technologies, SCR Cost Development Methodology, Chapter 5, Attachment 5-3, January 2017. Available at: https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-	
Electricity Cost ($/kWh)	0.0361	U.S. Energy Information Administration. Electric Power Annual 2016. Table 8.4. Published December 2017. Available at: https://www.eia.gov/electricity/annual/pdf/epa.pdf.	
Percent sulfur content for Coal (% weight)	0.41	Average sulfur content based on U.S. coal data for 2016 compiled by the U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Higher Heating Value (HHV) (Btu/lb)	8,826	2016 coal data compiled by the Office of Oil, Gas, and Coal Supply Statistics, U.S. Energy Information Administration (EIA) from data reported on EIA Form EIA-923, Power Plant Operations Report. Available at http://www.eia.gov/electricity/data/eia923/.	
Catalyst Cost ($/cubic foot)	227	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Operator Labor Rate ($/hour)	$60.00	U.S. Environmental Protection Agency (EPA). Documentation for EPA's Power Sector Modeling Platform v6 Using the Integrated Planning Model. Office of Air and Radiation. May 2018. Available at: https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6.	
Interest Rate (Percent)	5.5	Default bank prime rate	

SCR Design Parameters

The following design parameters for the SCR were calculated based on the values entered on the *Data Inputs* tab. These values were used to prepare the costs shown on the *Cost Estimate* tab.

Parameter	Equation	Calculated Value	Units
Maximum Annual Heat Input Rate (Q_B) =	Bmw x NPHR =	7,544	MMBtu/hour
Maximum Annual MW Output (Bmw) =	Bmw x 8760 =	7,051,800	MWhs
Estimated Actual Annual MWhs Output (Boutput) =		5,262,954	MWhs
Heat Rate Factor (HRF) =	NPHR/10 =	0.94	
Total System Capacity Factor (CF_{total}) =	(Boutput/Bmw)*(tscr/tplant) =	0.746	fraction
Total operating time for the SCR (t_{op}) =	CF_{total} x 8760 =	6538	hours
NOx Removal Efficiency (EF) =	(NOx_{in} - NOx_{out})/NOx_{in} =	59.3	percent
NOx removed per hour =	NOx_{in} x EF x Q_B =	660.52	lb/hour
Total NO_x removed per year =	(NOx_{in} x EF x Q_B x t_{op})/2000 =	2,159.19	tons/year
NO_x removal factor (NRF) =	EF/80 =	0.74	
Volumetric flue gas flow rate ($q_{flue\ gas}$) =	Q_{fuel} x QB x (460 + T)/(460 + 700)n_{scr} =	3,724,745	acfm
Space velocity (V_{space}) =	$q_{flue\ gas}$/$Vol_{catalyst}$ =	158.14	/hour
Residence Time	1/V_{space}	0.01	hour
Coal Factor (CoalF) =	1 for oil and natural gas; 1 for bituminous; 1.05 for sub-bituminous; 1.07 for lignite (weighted average is used for coal blends)	1.05	
SO_2 Emission rate =	(%S/100)x(64/32)*1x10^6)/HHV =	< 3	lbs/MMBtu
Elevation Factor (ELEVF) =	14.7 psia/P =	1.13	
Atmospheric pressure at sea level (P) =	2116 x [(59-(0.00356xh)+459.7)/518.6]$^{5.256}$ x (1/144)* =	13.1	psia
Retrofit Factor (RF)	Retrofit to existing boiler	1.30	

* Equation is from the National Aeronautics and Space Administration (NASA), Earth Atmosphere Model. Available at https://spaceflightsystems.grc.nasa.gov/education/rocket/atmos.html.

Catalyst Data:

Parameter	Equation	Calculated Value	Units
Future worth factor (FWF) =	(interest rate)(1/((1+ interest rate)^Y -1) , where Y = $H_{catalyts}$/(t_{SCR} x 24 hours) rounded to the nearest integer	0.3157	Fraction
Catalyst volume ($Vol_{catalyst}$) =	2.81 x Q_B x EF_{adj} x $Slip_{adj}$ x NOx_{adj} x S_{adj} x (T_{adj}/N_{scr})	23,553.25	Cubic feet
Cross sectional area of the catalyst ($A_{catalyst}$) =	$q_{flue\ gas}$ /(16ft/sec x 60 sec/min)	3,880	ft^2
Height of each catalyst layer (H_{layer}) =	($Vol_{catalyst}$/(R_{layer} x $A_{catalyst}$)) + 1 (rounded to next highest integer)	3	feet

SCR Reactor Data:

Parameter	Equation	Calculated Value	Units
Cross sectional area of the reactor (A_{SCR}) =	1.15 x $A_{catalyst}$	4,462	ft^2
Reactor length and width dimensions for a square reactor =	(A_{SCR})$^{0.5}$	66.8	feet
Reactor height =	(R_{layer} + R_{empty}) x (7ft + h_{layer}) + 9ft	49	feet

Reagent Data:

Type of reagent used	Urea		Molecular Weight of Reagent (MW) =	60.06 g/mole
			Density =	71 lb/ft^3

Parameter	Equation	Calculated Value	Units
Reagent consumption rate ($m_{reagent}$) =	(NOx_{in} x Q_B x EF x SRF x MW_R)/MW_{NOx} =	453	lb/hour
Reagent Usage Rate (m_{sol}) =	$m_{reagent}$/C_{sol} =	905	lb/hour
	(m_{sol} x 7.4805)/Reagent Density	95	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 24)/Reagent Density =	32,100	gallons (storage needed to store a 14 day reagent supply rounded to t

Capital Recovery Factor:

Parameter	Equation	Calculated Value
Capital Recovery Factor (CRF) =	i (1+ i)^n/(1+ i)^n - 1 = Where n = Equipment Life and i= Interest Rate	0.0688

Other parameters	Equation	Calculated Value	Units
Electricity Usage:			
Electricity Consumption (P) =	A x 1,000 x 0.0056 x (CoalF x HRF)$^{0.43}$ = where A = Bmw for utility boilers	4476.75	kW

SCR Cost Estimate

Total Capital Investment (TCI)

TCI for Coal-Fired Boilers

For Coal-Fired Boilers:

$$TCI = 1.3 \times (SCR_{cost} + RPC + APHC + BPC)$$

Capital costs for the SCR (SCR$_{cost}$) =	$220,836,664	in 2018 dollars
Reagent Preparation Cost (RPC) =	$4,138,327	in 2018 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2018 dollars
Balance of Plant Costs (BPC) =	$14,214,454	in 2018 dollars
Total Capital Investment (TCI) =	$310,946,279	in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emits equal to or greater than 3lb/MMBtu of sulfur dioxide.

SCR Capital Costs (SCR$_{cost}$)

For Coal-Fired Utility Boilers >25 MW:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (B_{MW} \times HRF \times CoalF)^{0.92} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$SCR_{cost} = 310,000 \times (NRF)^{0.2} \times (0.1 \times Q_B \times CoalF)^{0.92} \times ELEVF \times RF$$

SCR Capital Costs (SCR$_{cost}$) =	$220,836,664 in 2018 dollars

Reagent Preparation Costs (RPC)

For Coal-Fired Utility Boilers >25 MW:

$$RPC = 564,000 \times (NOx_{in} \times B_{MW} \times NPHR \times EF)^{0.25} \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$RPC = 564,000 \times (NOx_{in} \times Q_B \times EF)^{0.25} \times RF$$

Reagent Preparation Costs (RPC) =	$4,138,327 in 2018 dollars

Air Pre-Heater Costs (APHC)*

For Coal-Fired Utility Boilers >25MW:

$$APHC = 69,000 \times (B_{MW} \times HRF \times CoalF)^{0.78} \times AHF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$APHC = 69,000 \times (0.1 \times Q_B \times CoalF)^{0.78} \times AHF \times RF$$

Air Pre-Heater Costs (APH$_{cost}$) =	$0 in 2018 dollars

* Not applicable - This factor applies only to coal-fired boilers that burn bituminous coal and emit equal to or greater than 3lb/MMBtu of sulfur dioxide.

Balance of Plant Costs (BPC)

For Coal-Fired Utility Boilers >25MW:

$$BPC = 529,000 \times (B_{MW} \times HRF \times CoalF)^{0.42} \times ELEVF \times RF$$

For Coal-Fired Industrial Boilers >250 MMBtu/hour:

$$BPC = 529,000 \times (0.1 \times Q_B \times CoalF)^{0.42}\ ELEVF \times RF$$

Balance of Plant Costs (BOP$_{cost}$) =	$14,214,454 in 2018 dollars

Annual Costs

Total Annual Cost (TAC)
TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$6,347,422 in 2018 dollars
Indirect Annual Costs (IDAC) =	$21,414,389 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	$27,761,811 in 2018 dollars

Direct Annual Costs (DAC)

DAC = (Annual Maintenance Cost) + (Annual Reagent Cost) + (Annual Electricity Cost) + (Annual Catalyst Cost)

Annual Maintenance Cost =	$0.005 \times TCI =$	$1,554,731 in 2018 dollars
Annual Reagent Cost =	$m_{sol} \times Cost_{reag} \times t_{op} =$	$1,331,849 in 2018 dollars
Annual Electricity Cost =	$P \times Cost_{elect} \times t_{op} =$	$1,056,584 in 2018 dollars
Annual Catalyst Replacement Cost =		$2,404,257 in 2018 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	$n_{scr} \times Vol_{cat} \times (CC_{replace}/R_{layer}) \times FWF$	* Calculation Method 2 selected.
Method 2 (for coal-fired utility boilers):	$B_{MW} \times 0.4 \times (CoalF)^{2.9} \times (NRF)^{0.71} \times (CC_{replace}) \times 35.3$	
Direct Annual Cost =		$6,347,422 in 2018 dollars

Indirect Annual Cost (IDAC)
IDAC = Administrative Charges + Capital Recovery Costs

Administrative Charges (AC) =	$0.03 \times$ (Operator Cost + $0.4 \times$ Annual Maintenance Cost) =	$21,285 in 2018 dollars
Capital Recovery Costs (CR)=	$CRF \times TCI =$	$21,393,104 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$21,414,389 in 2018 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$27,761,811 per year in 2018 dollars
NOx Removed =	2,159 tons/year
Cost Effectiveness =	$12,858 per ton of NOx removed in 2018 dollars

Table B-1. RBLC Search Results for NO$_X$ Controls for Coal-Fired Utility- and Large Industrial-Size Boilers/Furnaces (> 250 MMBtu/hr)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT NUMBER	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION
AR-0094	JOHN W. TURK JR. POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY	2123-AOP-R0	11/5/2008	PC BOILER	PRB SUB-BIT COAL	6000	MMBTU/H	SELECTIVE CATALYTIC REDUCTION (SCR)
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ 08-01	2/6/2012	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ 08-01	2/6/2012	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ 08-01	2/6/2012	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	LOW NOX BURNER (LNB), SEPARATED OVERFIRE AIR (SOFA) SYSTEM
CA-1206	STOCKTON COGEN COMPANY	APMC STOCKTON COGEN	SJ 85-04	9/16/2011	CIRCULATING FLUIDIZED BED BOILER	COAL	730	MMBTU/H	LOW BED TEMPERATUR STAGED COMBUSTION; SELECTIVE NON-CATALYTIC REDUCTION (SNCR)
KY-0100	J.K. SMITH GENERATING STATION	EAST KENTUCKY POWER COOPERATIVE, INC	V-05-070 R3	4/9/2010	CIRCULATING FLUIDIZED BED BOILER CFB1 AND CFB2	COAL	3000	MMBTU/H	SNCR
LA-0148	ACTIVATED CARBON FACILITY	RED RIVER ENVIRONMENTAL PRODUCTS LLC	PSD-LA-727	5/28/2008	MULTIPLE HEARTH FURNACES / AFTERBURNERS	COAL	7.78	LB/YR E +08	COMBUSTION CONTROLS (INCLUDING LOW-NOX BURNERS) AND SNCR
LA-0176	BIG CAJUN II POWER PLANT	LOUISIANA GENERATING, LLC	PSD-LA-677	8/22/2005	NEW 675 MW PULVERIZED COAL BOILER (UNIT 4)	SUBBITUMINOUS COAL	3518791	T/YR	LOW NOX BURNERS AND SELECTIVE CATALYTIC REDUCTION
MI-0389	KARN WEADOCK GENERATING COMPLEX	CONSUMERS ENERGY	341-07	12/29/2009	BOILER	PRB COAL OR 50/50 BLEND	8190	MMBTU/H	LOW NOX BURNER, OVER-FIRED AIR, SELECTIVE CATALYTIC REDUCTION.
MI-0399	DETROIT EDISON-- MONROE	DETROIT EDISON	93-09A	12/21/2010	Boiler Units 1, 2, 3 and 4	Coal	7624	MMBTU/H	Staged combustion, low-NOx burners, overfire air, and SCR.
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	317-07	6/29/2011	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2)	Petcoke/coal	3030	MMBTU/H EACH	SNCR (Selective Non-Catalytic Reduction)
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	317-07	6/29/2011	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2) - EXCLUDING Startup & Shutdown	Petcoke/coal	3030	MMBTU/H each	SNCR (Selective Non-Catalytic Reduction)
MO-0060	CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	CITY UTILITIES OF SPRINGFIELD	122004-007	12/15/2004	PULVERIZED COAL FIRED BOILER	COAL	2724	MMBTU/H	IT WAS DETERMINED THAT THE BACT FOR NOX FROM THE PULVERIZED COAL FIRED BOILER IS GOOD COMBUSTION PRACTICES ALONG WITH SCR HAVING A NOX EMISSION LIMIT OF 0.08 LB/MMBTU ON A 30-DAY ROOLING AVERAGE.

Table B-1 (cont.). RBLC Search Results for NO$_X$ Controls for Coal-Fired Utility- and Large Industrial-Size Boilers/Furnaces (> 250 MMBtu/hr)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT NUMBER	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	GREAT PLAINS ENERGY	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 2	PULVERIZED COAL	4000	T/H	KCPL SHALL INSTALL SCR UNIT FOR THE UNIT 2 BOILER TO REDUCE NOX EMISSIONS AND ALSO SHALL INSTALL WET SCRUBBER TO REDUCE SOX EMISSIONS. BOTH CONTROLS ARE NOT BACT FOR NOX AND SOX
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	GREAT PLAINS ENERGY	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 1	COAL	4000	T/H	
MO-0077	NORBORNE POWER PLANT	ASSOCIATED ELECTRIC COOPERATIVE, INC	022008-010	2/22/2008	MAIN BOILER	COAL	3762420	T/YR	SCR - SELECTIVE CATALYTIC REDUCTION LNB - LOW NOX BURNERS OFA - OVERFIRE AIR
ND-0021	GASCOYNE GENERATING STATION	MONTANA DAKOTA UTILITIES / WESTMORELAND POWER	PTC 05005	6/3/2005	BOILER, COAL-FIRED	LIGNITE	2116	MMBTU/H	FLUIDIZED BED COMBUSTION AND SELECTIVE NON-CATALYTIC REDUCTION (SNCR).
ND-0024	SPIRITWOOD STATION	GREAT RIVER ENERGY	PTC07026	9/14/2007	ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	LIGNITE	1280	MMBTU/H	FLUIDIZED BED COMBUSTION AND SELECTIVE NON-CATALYTIC REDUCTION
ND-0026	M.R. YOUNG STATION	MINNKOTA POWER COOPERATIVE	PTC12003	3/8/2012	Cyclone Boilers, Unit 1	Lignite	3200	MMBTU/H	SNCR plus separated over fire air
ND-0026	M.R. YOUNG STATION	MINNKOTA POWER COOPERATIVE	PTC12003	3/8/2012	Cyclone Boilers, Unit 2	Lignite	6300	MMBTU/H	SNCR plus separated over fire air
NE-0018	WHELAN ENERGY CENTER	HASTINGS UTILITIES	58048	3/30/2004	BOILER, UNIT 2 UTILITY	SUBBITUMINOUS COAL	2210	MMBTU/H	SELECTIVE CATALYTIC REDUCTION
NE-0031	OPPD - NEBRASKA CITY STATION	OMAHA PUBLIC POWER DISTRICT	58343C01	3/9/2005	UNIT 2 BOILER	SUBBITUMINOUS COAL			SELECTIVE CATALYTIC REDUCTION (SCR)
NE-0049	OPPD NEBRASKA CITY STATION	OMAHA PUBLIC POWER DISTRICT	CP07-0049	2/26/2009	NCS UNIT 1	POWDER RIVER BASIN COAL	370	T/YR	LNB W/OVERFIRE AIR PORT SYSTEM
NV-0036	TS POWER PLANT	NEWMONT NEVADA ENERGY INVESTMENT, LLC	AP4911-1349	5/5/2005	200 MW PC COAL BOILER	POWDER RIVER BASIN COAL	2030	MMBTU/H	SCR & LOW NOX BURNERS
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	AMERICAN MUNICIPAL POWER	P0104461	10/8/2009	BOILER (2), PULVERIZED COAL FIRED	PULVERIZED COAL	5191	MMBTU/H	SELECTIVE CATALYTIC REDUCTION
OH-0314	SMART PAPERS HOLDINGS, LLC	SMART PAPERS HOLDINGS, LLC	14-05962	1/31/2008	PULVERIZED DRY BOTTOM BOILER	COAL	420	MMBTU/H	
OH-0314	SMART PAPERS HOLDINGS, LLC	SMART PAPERS HOLDINGS, LLC	14-05962	1/31/2008	SPREADER STOKER COAL-FIRED BOILER	COAL	249	MMBTU/H	
OK-0118	HUGO GENERATING STA	WESTERN FARMERS ELECTRIC COOP	97-058-C M-2 PSD	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)		750	MW	LOW NOX BURNERS (LNB) W/ OVERFIRE AIR (OFA) AND SELECTIVE CATALYTIC REDUCTION (SCR)
OK-0151	SOONER GENERATING STATION	O G AND E	2010-338-C(M-1)PSD	1/17/2013	COAL-FIRED BOILERS	COAL	550	MW	LOW-NOx BURNERS AND OVERFIRE AIR.
OK-0152	MUSKOGEE GENERATING STATION	O G AND E	2005-271-C(M-5)PSD	1/30/2013	COAL-FIRED BOILER	COAL	550	MW	LOW-NOx BURNERS AND OVERFIRE AIR

Table B-1 (cont.). RBLC Search Results for NO$_X$ Controls for Coal-Fired Utility- and Large Industrial-Size Boilers/Furnaces (> 250 MMBtu/hr)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT NUMBER	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION
PA-0247	BEECH HOLLOW POWER PROJECT	ROBINSON POWER COMPANY LLC	63-00922A	4/1/2005	COAL FIRED CFB	WASTE COAL			SNCR EMPLOYED TO MINIMIZE NOX EMISSIONS. FACILITY WILL BE EQUIPPED WITH NOX CEM TO MONITOR EXHAUST GAS STREAM.
PA-0248	GREENE ENERGY RESOURCE RECOVERY PROJECT	WELLINGTON DEV/GREENE ENERGY	30-00150A	7/8/2005	2 CFB BOILERS	WASTE COAL	358	T/H (each)	SNCR, NOX CEM
PA-0249	RIVER HILL POWER COMPANY, LLC	RIVER HILL POWER COMPANY, LLC	17-00055A	7/21/2005	CFB BOILER	WASTE COAL			SNCR INSTALLED. NOX EMISSIONS MONITORED BY CEM
PA-0257	SUNNYSIDE ETHANOL,LLC	SUNNYSIDE ETHANOL,LLC	17-313-001	5/7/2007	CFB BOILER	COAL	496.8	MMBTU/H	SNCR
PA-0259	CAMBRIA COKE CO.	CAMBRIA COKE CO.	11-00332	8/25/2006	PYROPOWER UNIT A	COAL			COMBUSTION STAGING
PA-0259	CAMBRIA COKE CO.	CAMBRIA COKE CO.	11-00332	8/25/2006	PYROPOWER UNIT B	COAL			COMBUSTION STAGING
SC-0104	SANTEE COOPER CROSS GENERATING STATION	SANTEE COOPER	0420-0030-CI	2/5/2004	BOILER, NO. 3 AND NO. 4	BITUMINOUS COAL	5700	MMBTU/H	LOW NOX BURNERS AND SCR
TX-0489	SOUTHWESTERN PUBLIC SERVICE COMPANY-HARRINGTON STATION	SOUTHWESTERN PUBLIC SERVICE COMPANY	P017M1	10/17/2006	UNIT 3 BOILER	PBR COAL	3870	MMBtu/h	LOW NOX BURNERS, SEPARATED OVERFIRE AIR WINDBOX, WITH ADDITIONAL YAW CONTROL OF THE BURNERS FOR ADDITIONAL NOX CONTROL
TX-0491	MEADWESTVACO TEXAS LP PULP AND PAPER MILL	MEADWESTVACO TEXAS LP	P785M7	1/24/2007	NO. 6 POWER BOILER	SCRAP WOOD AND BARK			OVERFIRE AIR
TX-0499	SANDY CREEK ENERGY STATION	SANDY CREEK ENERGY ASSOCIATES	PSD-TX 1039 AND 70861	7/24/2006	PULVERIZED CAOL BOILER	COAL	8185	MMBTU/H	AT THIS POINT, THE FLUE GAS HAS BEEN COOLED TO THE APPROPRIATE TEMPERATURE FOR SCR, SO IT NEXT PASSES THROUGH THE SCR REACTOR, WHERE NOX IS REDUCED TO FORM NITROGEN.
TX-0518	VALERO HEAVY OIL CRACKER	VALERO REFINING	PSD-TX 324M12 AND 38754	11/16/2005	EMISSIONS				
TX-0554	COLETO CREEK UNIT 2	COLETO CREEK	PSDTX1118	5/3/2010	Coal-fired Boiler Unit 2	PRB coal	6670	MMBTU/H	low-NOx burners with OFA, Selective Catalytic Reduction
TX-0556	HARRINGTON STATION UNIT 1 BOILER	SOUTHWESTERN PUBLIC SERVICE COMPANY	PSDTX631M1	1/15/2010	Unit 1 Boiler	Coal	3630	MMBTU/H	Separated overfire air windbox system; low-NOx burner tips and additional ya control to the burners.
TX-0557	LIMESTONE ELECTRIC GENERATING STATION	NRG TEXAS POWER LLC	PSDTX371M4	2/1/2010	LMS Units 1 and 2	Coal	9061	MMBtu/H	Tuning of existing low-NOx firing system to induce deeper state combustion.
TX-0577	WHITE STALLION ENERGY CENTER	WHITE STALLION ENERGY CENTER, LLC	86088	12/16/2010	CFB BOILER	COAL & PET COKE	3300	MMBTU/H	CFB AND SNCR
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	TENASKA TRAILBLAZER PARTNERS LLC	PSDTX1123	12/30/2010	Coal-fired Boiler	Sub-bituminous coal	8307	MMBTU/H	Selective Catalytic Reduction

Table B-1 (cont.). RBLC Search Results for NO$_X$ Controls for Coal-Fired Utility- and Large Industrial-Size Boilers/Furnaces (> 250 MMBtu/hr)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT NUMBER	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION
TX-0593	TEXAS CLEAN ENERGY PROJECT	SUMMIT TEXAS CLEAN ENERGY	PSDTX1218	12/28/2010	Integrated Gasification Combined Cycle	PRB coal	400	MW	SCR
UT-0064	SEVIER POWER COMPANY	NEVCO - SEVIER POWER COMPANY	DAQE-AN2529001-04	10/12/2004	LOW-NOX BURNERS WITH SNCR (SELECTIVE NON-CATALYTIC REDUCTION)	WESTERN COAL	270	MW	LOW NOX BURNERS WITH SNCR WITH AMMONIA INJECTION
UT-0065	INTERMOUNTAIN POWER GENERATING STATION - UNIT #3	INTERMOUNTAIN POWER SERVICE CORPORATION	DAQE-AN0327010-04	10/15/2004	PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT	BITUMINOUS OR BLEND	950	MW-gross	LOW NOX BURNERS, OVER FIRE AIR, SCR
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	DESERET POWER ELECTRIC COOPERATIVE	PSD-OU-0002-04.00	8/30/2007	CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR WASTE COAL FIRED	WASTE COAL/ BITUMINOUS BLEND			SNCR
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	DESERET POWER ELECTRIC COOPERATIVE	PSD-OU-0002-04.00	8/30/2007	CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR WASTE COAL FIRED	WASTE COAL/ BITUMINOUS BLEND			SNCR
VA-0296	VIRGINIA TECH	VIRGINIA POLYTECHNIC INSTITUTE AND STATE UNIVERSIT	20124	9/15/2005	OPERATION OF BOILER 11	COAL	146.7	mmbtu	EMISSIONS CONTROLLED BY A MASS-FEED STOKER CONFIGURATION WITH LOW EXCESS AIR/STAGED COMBUSTION
VA-0309	GEORGIA PACIFIC WOOD PRODUCTS - JARRATT	GEORGIA PACIFIC WOOD PRODUCTS	50253	5/15/2008	KEELER BOILER	COAL	86.6	MMBTU/H	GOOD COMBUSTION PRACTICES AND CEM SYSTEM.
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	VIRGINIA ELECTRIC AND POWER CO	11526	6/30/2008	2 CIRCULATING FLUIDIZED BED BOILERS	COAL AND COAL REFUSE	3132	MMBTU/H	SELECTIVE NON-CATALYTIC REDUCTION AND GOOD COMBUSTION PRACTICES AND CEM SYSTEM
WI-0228	WPS - WESTON PLANT	WISCONSIN PUBLIC SERVICE	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	5173.07	MMBTU/H	LOW NOX BURNERS, GOOD COMBUSTION PRACTICES SELECTIVE CATALYTIC REDUCTION (SCR)
WV-0023	MAIDSVILLE	LONGVIEW POWER, LLC	R14-0024	3/2/2004	BOILER, PC	PULVERIZED COAL	6114	MMBTU/H	LOW-NOX BURNERS IN SERIES WITH SCR
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	WESTERN GREENBRIER CO-GENERATION, LLC	R14-0028	4/26/2006	CIRCULATING FLUIDIZED BED BOILER (CFB)	WASTE COAL	1070	mmbtu/h	SNCR
WY-0063	WYGEN 3	BLACK HILLS CORPORATION	CT-4517	2/5/2007	PC BOILER	SUBBITUMINOUS COAL	1300	MMBTU/H	SCR/LNB/OVERFIRE AIR
WY-0064	DRY FORK STATION	BASIN ELECTRIC POWER COOPERATIVE	CT-4631	10/15/2007	PC BOILER (ES1-01)	COAL			LOW NOX BURNERS AND SCR

Table C-1. RBLC Search Results for SO$_2$ Controls for Coal-Fired Utility- and Large Industrial-Size Boilers/Furnaces (> 250 MMBtu/hr)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT NUMBER	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION
AR-0094	JOHN W. TURK JR. POWER PLANT	SOUTHWEST ELECTRIC POWER COMPANY	2123-AOP-R0	11/5/2008	PC BOILER	PRB SUB-BIT COAL	6000	MMBTU/H	DRY FLUE GAS DESULFURIZATION (SPRAY DRY ADSORBER)
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ 08-01	2/6/2012	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	FLUE GAS DESULFURIZATION (FGD), SCRUBBER
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ 08-01	2/6/2012	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	FLUE GAS DESULFURIZATION (FGD), SCRUBBER
AZ-0055	NAVAJO GENERATING STATION	SALT RIVER PROJECT AGRICULTURAL AND POWER DISTRICT	AZ 08-01	2/6/2012	PULVERIZED COAL FIRED BOILER	COAL	7725	MMBTU/H	FLUE GAS DESULFURIZATION (FGD), SCRUBBER
CA-1206	STOCKTON COGEN COMPANY	APMC STOCKTON COGEN	SJ 85-04	9/16/2011	CIRCULATING FLUIDIZED BED BOILER	COAL	730	MMBTU/H	LIMESTONE INJECTION W/ A MINIMUM REMOVAL EFFICIENCY OF 70% (3-HR AVG) TO BE MAINTAINED AT ALL TIMES
KY-0100	J.K. SMITH GENERATING STATION	EAST KENTUCKY POWER COOPERATIVE, INC	V-05-070 R3	4/9/2010	CIRCULATING FLUIDIZED BED BOILER CFB1 AND CFB2	COAL	3000	MMBTU/H	LIMESTONE INJECTION (CFB)AND A FLASH DRYER ABSORBER WITH FRESH LIME INJECTION
LA-0148	ACTIVATED CARBON FACILITY	RED RIVER ENVIRONMENTAL PRODUCTS LLC	PSD-LA-727	5/28/2008	MULTIPLE HEARTH FURNACES / AFTERBURNERS	COAL	7.78	LB/YR E +08	SPRAY DRYER ABSORBER (SDA) SYSTEM
LA-0176	BIG CAJUN II POWER PLANT	LOUISIANA GENERATING, LLC	PSD-LA-677	8/22/2005	NEW 675 MW PULVERIZED COAL BOILER (UNIT 4)	SUBBITUMINOUS COAL	3518791	T/YR	OPTION 1: SEMI-DRY LIME SCRUBBER OPTION 2: WET FLUE GAS DESULFURIZATION SYSTEM
MI-0389	KARN WEADOCK GENERATING COMPLEX	CONSUMERS ENERGY	341-07	12/29/2009	BOILER	PRB COAL OR 50/50 BLEND	8190	MMBTU/H	LIMESTONE FORCED OXIDATION, WET FLUIDIZED GAS DESULFURIZATION (FGD) AND LOW SULFUR COAL.
MI-0399	DETROIT EDISON-- MONROE	DETROIT EDISON	93-09A	12/21/2010	Boiler Units 1, 2, 3 and 4	Coal	7624	MMBTU/H	Wet flue gas desulfurization.
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	317-07	6/29/2011	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2)	Petcoke/coal	3030	MMBTU/H EACH	Dry flue gas desulfurization (spray dry absorber or polishing scrubber).
MI-0400	WOLVERINE POWER	WOLVERINE POWER SUPPLY COOPERATIVE, INC.	317-07	6/29/2011	2 Circulating Fluidized Bed Boilers (CFB1 & CFB2) - EXCLUDING Startup & Shutdown	Petcoke/coal	3030	MMBTU/H each	Dry flue gas desulfurization (spray dry absorber or polishing scrubber).
MO-0060	CITY UTILITIES OF SPRINGFIELD - SOUTHWEST POWER STATION	CITY UTILITIES OF SPRINGFIELD	122004-007	12/15/2004	PULVERIZED COAL FIRED BOILER	COAL	2724	MMBTU/H	DRY FLUE GAS DESULFURIZATION > 90%

Table C-1 (cont.). RBLC Search Results for SO$_2$ Controls for Coal-Fired Utility- and Large Industrial-Size Boilers/Furnaces (> 250 MMBtu/hr)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT NUMBER	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	GREAT PLAINS ENERGY	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 2	PULVERIZED COAL	4000	T/H	KCPL SHALL INSTALL SCR UNIT FOR THE UNIT 2 BOILER TO REDUCE NOX EMISSIONS AND ALSO SHALL INSTALL WET SCRUBBER TO REDUCE SOX EMISSIONS. BOTH CONTROLS ARE NOT BACT FOR NOX AND SOX
MO-0071	KANSAS CITY POWER & LIGHT COMPANY - IATAN STATION	GREAT PLAINS ENERGY	012006-019	1/27/2006	PULVERIZED COAL BOILER - UNIT 1	COAL	4000	T/H	
MO-0077	NORBORNE POWER PLANT	ASSOCIATED ELECTRIC COOPERATIVE, INC	022008-010	2/22/2008	MAIN BOILER	COAL	3762420	T/YR	DRY FLUE GAS DESUL
ND-0021	GASCOYNE GENERATING STATION	MONTANA DAKOTA UTILITIES / WESTMORELAND POWER	PTC 05005	6/3/2005	BOILER, COAL-FIRED	LIGNITE	2116	MMBTU/H	LIMESTONE INJECTION WITH A SPRAY DRYER.
ND-0024	SPIRITWOOD STATION	GREAT RIVER ENERGY	PTC07026	9/14/2007	ATMOSPHERIC CIRCULATING FLUIDIZED BED BOILER	LIGNITE	1280	MMBTU/H	LIMESTONE INJECTION INTO THE UNIT WITH A SPRAY DRYER FOLLOWING.
NE-0018	WHELAN ENERGY CENTER	HASTINGS UTILITIES	58048	3/30/2004	BOILER, UNIT 2 UTILITY	SUBBITUMINOUS COAL	2210	MMBTU/H	SPRAY DRYER ABSORBER (SDA)
NE-0031	OPPD - NEBRASKA CITY STATION	OMAHA PUBLIC POWER DISTRICT	58343C01	3/9/2005	UNIT 2 BOILER	SUBBITUMINOUS COAL			DRY FLUE GAS DESULFURIZATION & FABRIC FILTER
NV-0036	TS POWER PLANT	NEWMONT NEVADA ENERGY INVESTMENT, LLC	AP4911-1349	5/5/2005	200 MW PC COAL BOILER	POWDER RIVER BASIN COAL	2030	MMBTU/H	LIME SPRAY SPRAY DRY SCRUBBER
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	AMERICAN MUNICIPAL POWER	P0104461	10/8/2009	BOILER (2), PULVERIZED COAL FIRED	PULVERIZED COAL	5191	MMBTU/H	WET FLUE GAS DESULFURIZATION (FGS) EITHER LIME OR AMMONIA-BASED
OH-0314	SMART PAPERS HOLDINGS, LLC	SMART PAPERS HOLDINGS, LLC	14-05962	1/31/2008	PULVERIZED DRY BOTTOM BOILER	COAL	420	MMBTU/H	
OH-0314	SMART PAPERS HOLDINGS, LLC	SMART PAPERS HOLDINGS, LLC	14-05962	1/31/2008	SPREADER STOKER COAL-FIRED BOILER	COAL	249	MMBTU/H	
OK-0118	HUGO GENERATING STA	WESTERN FARMERS ELECTRIC COOP	97-058-C M-2 PSD	2/9/2007	COAL-FIRED STEAM EGU BOILER (HU-UNIT 2)		750	MW	WET LIMESTONE FLUE GAS DESULFURIZATION
PA-0247	BEECH HOLLOW POWER PROJECT	ROBINSON POWER COMPANY LLC	63-00922A	4/1/2005	COAL FIRED CFB	WASTE COAL			LIMESTONE INJECTION WITH FLY ASH HYDRATION AND REINJECTION. LIMESTONE SORBENT WILL BE FED AT MAX. RATE OF APPROXIMATELY 79 TPH TO ACHIEVE CALCIUM-TO-SULFUR RATIO OF ABOUT 2.75:1 MONITORED BY CEM

Table C-1 (cont.). RBLC Search Results for SO$_2$ Controls for Coal-Fired Utility- and Large Industrial-Size Boilers/Furnaces (> 250 MMBtu/hr)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT NUMBER	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION
PA-0248	GREENE ENERGY RESOURCE RECOVERY PROJECT	WELLINGTON DEV/GREENE ENERGY	30-00150A	7/8/2005	2 CFB BOILERS	WASTE COAL	358	T/H (each)	EMISSION RESTRICTION, LIMESTONE INJECTION PLUS A DRY POLISHING SCRUBBER, EMISSION MONITORED BY CEM WHICH IS BASIS FOR EFFICIENCY CONTROL
PA-0249	RIVER HILL POWER COMPANY, LLC	RIVER HILL POWER COMPANY, LLC	17-00055A	7/21/2005	CFB BOILER	WASTE COAL			DRY FLUE GAS DESULFURIZATION SYSYTEM
PA-0257	SUNNYSIDE ETHANOL,LLC	SUNNYSIDE ETHANOL,LLC	17-313-001	5/7/2007	CFB BOILER	COAL	496.8	MMBTU/H	LIMESTONE INJECTION AND ADD ON DRY FLUE GAS DESULFEDRIZATION, CEM
PA-0259	CAMBRIA COKE CO.	CAMBRIA COKE CO.	11-00332	8/25/2006	PYROPOWER UNIT A	COAL			LIME INJECTION, SPRAY DRYER AND ADSORBER SYSTEM
PA-0259	CAMBRIA COKE CO.	CAMBRIA COKE CO.	11-00332	8/25/2006	PYROPOWER UNIT B	COAL			LIME INJECTION/SPRAY DRYER/ADSORBER SYSTEM
SC-0104	SANTEE COOPER CROSS GENERATING STATION	SANTEE COOPER	0420-0030-CI	2/5/2004	BOILER, NO. 3 AND NO. 4	BITUMINOUS COAL	5700	MMBTU/H	FLUE GAS DESULFURIZATION (WET SCRUBBING)
TX-0499	SANDY CREEK ENERGY STATION	SANDY CREEK ENERGY ASSOCIATES	PSD-TX 1039 AND 70861	7/24/2006	PULVERIZED CAOL BOILER	COAL	8185	MMBTU/H	
TX-0518	VALERO HEAVY OIL CRACKER	VALERO REFINING	PSD-TX 324M12 AND 38754	11/16/2005	EMISSIONS				
TX-0554	COLETO CREEK UNIT 2	COLETO CREEK	PSDTX1118	5/3/2010	Coal-fired Boiler Unit 2	PRB coal	6670	MMBTU/H	Spray Dry Adsorber/Fabric Filter
TX-0577	WHITE STALLION ENERGY CENTER	WHITE STALLION ENERGY CENTER, LLC	86088	12/16/2010	CFB BOILER	COAL & PET COKE	3300	MMBTU/H	LIMESTONE BED CFB AND LIME SPRAY DRYER PERMIT DESIGN SULFUR CONTENT OF ILL BASIN COAL IS 3.9 WT% AND OF PET COKE 4.3 AVG/6.0 MAX HI WEIGHTING OF LIMITS USED FOR FUEL BLENDING
TX-0585	TENASKA TRAILBLAZER ENERGY CENTER	TENASKA TRAILBLAZER PARTNERS LLC	PSDTX1123	12/30/2010	Coal-fired Boiler	Sub-bituminous coal	8307	MMBTU/H	Wet limestone scrubber
TX-0593	TEXAS CLEAN ENERGY PROJECT	SUMMIT TEXAS CLEAN ENERGY	PSDTX1218	12/28/2010	Integrated Gasification Combined Cycle	PRB coal	400	MW	gasification of coal and sulfur recovery in syngas before combustion in turbine and duct burners
UT-0064	SEVIER POWER COMPANY	NEVCO - SEVIER POWER COMPANY	DAQE-AN2529001-04	10/12/2004	CFB BOILER WITH DRY LIME SCRUBBER	WESTERN COAL	270	MW	LOW SULFUR COAL AND DRY LIME SCRUBBER
UT-0065	INTERMOUNTAIN POWER GENERATING STATION - UNIT #3	INTERMOUNTAIN POWER SERVICE CORPORATION	DAQE-AN0327010-04	10/15/2004	PULVERIZED COAL FIRED ELECTRIC GENERATING UNIT	BITUMINOUS OR BLEND	950	MW-gross	WET FLUE GAS DESULPHURIZATION, LOW SULFER COAL
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	DESERET POWER ELECTRIC COOPERATIVE	PSD-OU-0002-04.00	8/30/2007	CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR WASTE COAL FIRED	WASTE COAL/BITUMINO US BLEND			

Table C-1 (cont.). RBLC Search Results for SO$_2$ Controls for Coal-Fired Utility- and Large Industrial-Size Boilers/Furnaces (> 250 MMBtu/hr)

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	PERMIT NUMBER	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION
UT-0070	BONANZA POWER PLANT WASTE COAL FIRED UNIT	DESERET POWER ELECTRIC COOPERATIVE	PSD-OU-0002-04.00	8/30/2007	CIRCULATING FLUIDIZED BED BOILER, 1445 MMBTU/HR WASTE COAL FIRED	WASTE COAL/BITUMINOUS BLEND			LIMESTONE INJECTION SYSTEM DRY SO2 SCRUBBER (SPRAY DRY ABSORBER)
VA-0296	VIRGINIA TECH	VIRGINIA POLYTECHNIC INSTITUTE AND STATE UNIVERSIT	20124	9/15/2005	OPERATION OF BOILER 11	COAL	146.7	mmbtu	DRY SCRUBBER FLUE GAS DESULFURIZATION SYSTEM AND CEMS
VA-0309	GEORGIA PACIFIC WOOD PRODUCTS - JARRATT	GEORGIA PACIFIC WOOD PRODUCTS	50253	5/15/2008	KEELER BOILER	COAL	86.6	MMBTU/H	GOOD COMBUSTION PRACTICES LOW SULFUR CONTENT COAL AND CEM SYSTEM.
VA-0311	VIRGINIA CITY HYBRID ENERGY CENTER	VIRGINIA ELECTRIC AND POWER CO	11526	6/30/2008	2 CIRCULATING FLUIDIZED BED BOILERS	COAL AND COAL REFUSE	3132	MMBTU/H	LIMESTONE INJECTION AND FLUE GAS DESULFURIZATION AND CEM SYSTEM
WI-0228	WPS - WESTON PLANT	WISCONSIN PUBLIC SERVICE	04-RV-248	10/19/2004	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	5173.07	MMBTU/H	DRY FGD, LIMIT ON EMISSIONS ENTERING CONTROL SYSTEM: 1.23 LBS/MMBTU 30 DAY AVG.
WV-0023	MAIDSVILLE	LONGVIEW POWER, LLC	R14-0024	3/2/2004	BOILER, PC	PULVERIZED COAL	6114	MMBTU/H	WET LIMESTONE FORCED OXIDATION
WV-0024	WESTERN GREENBRIER CO-GENERATION, LLC	WESTERN GREENBRIER CO-GENERATION, LLC	R14-0028	4/26/2006	CIRCULATING FLUIDIZED BED BOILER (CFB)	WASTE COAL	1070	mmbtu/h	LIME INJECTION AND FLASH DRYER ABSORBER (FDA)
WY-0063	WYGEN 3	BLACK HILLS CORPORATION	CT-4517	2/5/2007	PC BOILER	SUBBITUMINOUS COAL	1300	MMBTU/H	DRY FGD
WY-0064	DRY FORK STATION	BASIN ELECTRIC POWER COOPERATIVE	CT-4631	10/15/2007	PC BOILER (ES1-01)	COAL			CIRCULATING DRY SCRUBBER