WUTC DOCKET: UE-200900 UG-200901 UE-200894
EXHIBIT: JRT-33X
ADMIT ☐ W/D ☐ REJECT ☑

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-20_____

EXH. JRT-10

JASON R. THACKSTON

REPRESENTING AVISTA CORPORATION

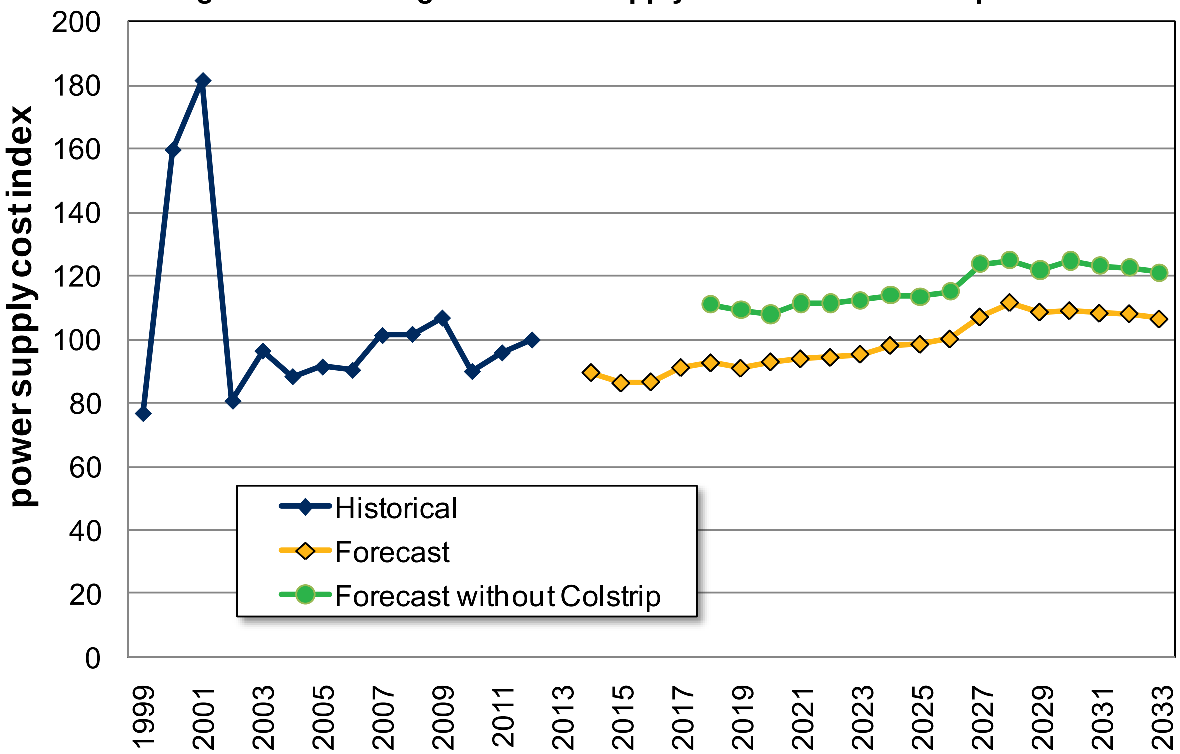
Exhibit JRT-10

Part 1: Avista Electric IRP Excerpts

Exhibit JRT-10

Part 1: 2013 Avista Electric IRP Excerpts

Figure 8.16: Change to Power Supply Cost without Colstrip



Environmental Control Review

There are potential costly regulations Colstrip Units 3 and 4 could face over the next 20 years of this resource plan if state or federal agencies promulgate new coal-fired generation environmental regulations. This section identifies anticipated regulations the EPA could establish over the time horizon of this plan based on information available during the development of this plan. The President's Climate Action Plan was released after the analysis for this IRP was completed, but details about the plan are in Chapter 4, Policy Considerations. Avista will monitor and review implications of the plan as they develop. This discussion is speculative unless otherwise noted and only pertain to Colstrip Units 3 and 4. The following section discusses four main areas of possible new environmental regulations.

Hazardous Air Pollutants

MATS is for the coal and oil-fired source category. For Colstrip Units 3 and 4, existing emission control systems should be sufficient to meet MATS limitations.

Coal Ash Management/Disposal

Avista does not anticipate a significant change in operation at Colstrip Units 3 and 4 due to coal ash management or disposal issues at this time.

Effluent Discharge Guidelines

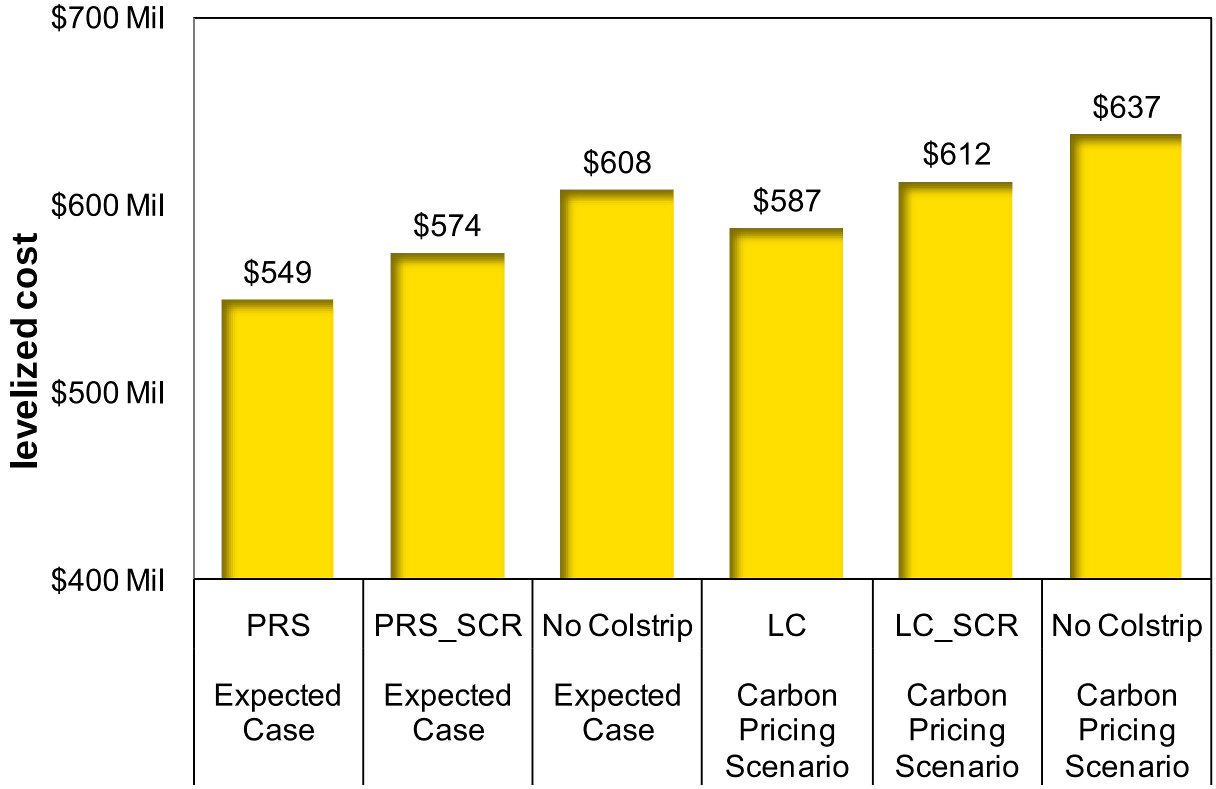
Avista does not anticipate a significant change in operation at Colstrip Units 3 and 4 due to coal ash management or disposal issues at this time because it is a zero discharge facility managing wastewater onsite.

Regional Haze Program

Colstrip Units 3 and 4 will be evaluated for reasonable progress on approximately 10-year intervals going forward. Avista anticipates Nitrous Oxides (NO_X) emission controls could be required in 2027. The cost to comply with this potential regulation is unknown due to technology changes potentially on the horizon to reduce NO_X emissions. In order to understand this regulation if imposed on Colstrip Units 3 and 4 using existing technology, a study was completed and submitted to EPA in 2010.

This study evaluates whether or not the cost of installing this existing technology would have an impact on the ongoing operations of the Colstrip Units 3 and 4. The study estimated the cost of a SCR NO_X control to be $280 million per unit (2011 dollars); Avista chose to increase these estimates by 25 percent to account for potential retrofit costs. Further, Avista believes these control costs are on the high end of the cost range. In this case, Avista's share of this cost for both units would be $105 million in capital, and about $560,000 in annual O&M (2014$). Over the life of this technology, the levelized cost of the controls is $8.39 per MWh (2014 dollars nominal). Further analysis is in Figure 8.17. This chart illustrates three scenarios for the two market price forecasts (Expected Case and Carbon Pricing Scenario). The results shown in the Expected Case's removal of Colstrip Units 3 and 4 from the portfolio adds $34 million or (6.1 percent) to power supply costs compared to installing the SCR controls scenario. In the Carbon Pricing Scenario, $25 million per year is added or 4.3 percent per year without Colstrip Units 3 and 4 compared to installing the SCR. Based on this study using high cost to comply with potential regional haze regulation costs, Colstrip Units 3 and 4 remain a viable and cost-effective resource for Avista's customers.

Figure 8.17: Annual Levelized Cost (2027-33) of Colstrip Scenarios



Other Portfolio Scenarios

Avista examined a number of possible policy outcomes affecting future resource selection. These scenarios review how Avista's resource strategy might change in response to new policies

Higher Washington RPS

Avista's current resource mix fully meets the EIA, but it is possible new legislation or a citizen's initiative could increase the renewable goals further. This scenario contemplates this change to understand the resulting cost, risk, and emissions impacts. The scenario assumes an additional step in the renewable goal of 25 percent of Washington retail sales to be from qualified renewables. Such a goal would require Avista to add 77 aMW of qualified renewables beyond the present plan. The PRiSM model found the most cost-effective method to meet this requirement, with a similar risk profile to the PRS would be Spokane River hydroelectric upgrades. Both Long Lake (68 MW) and Monroe Street (55 MW) second powerhouse additions would meet the renewable requirement if they were certified as EIA-qualifying resources. The addition of these upgrades would prevent the final natural gas peaking resource from being required in the PRS. While the 20-year levelized cost is slightly higher than the PRS, the costs between 2025 and 2033 are $18 million levelized higher, or 3.5 percent.

Colstrip Scenarios

- No Colstrip Resource Strategy Scenario
  - Colstrip is removed from portfolio beginning in 2018
  - No costs/benefits included due to its removal
- Regional Haze Program Scenario
  - Assumes Colstrip #3 & #4 must install SCR or shut down in 2027
  - SCR costs are expected to be $105 million (Avista share) plus $560k each year in O&M or $8.39/MWh total cost levelized

2027-33 Colstrip SCR Analysis

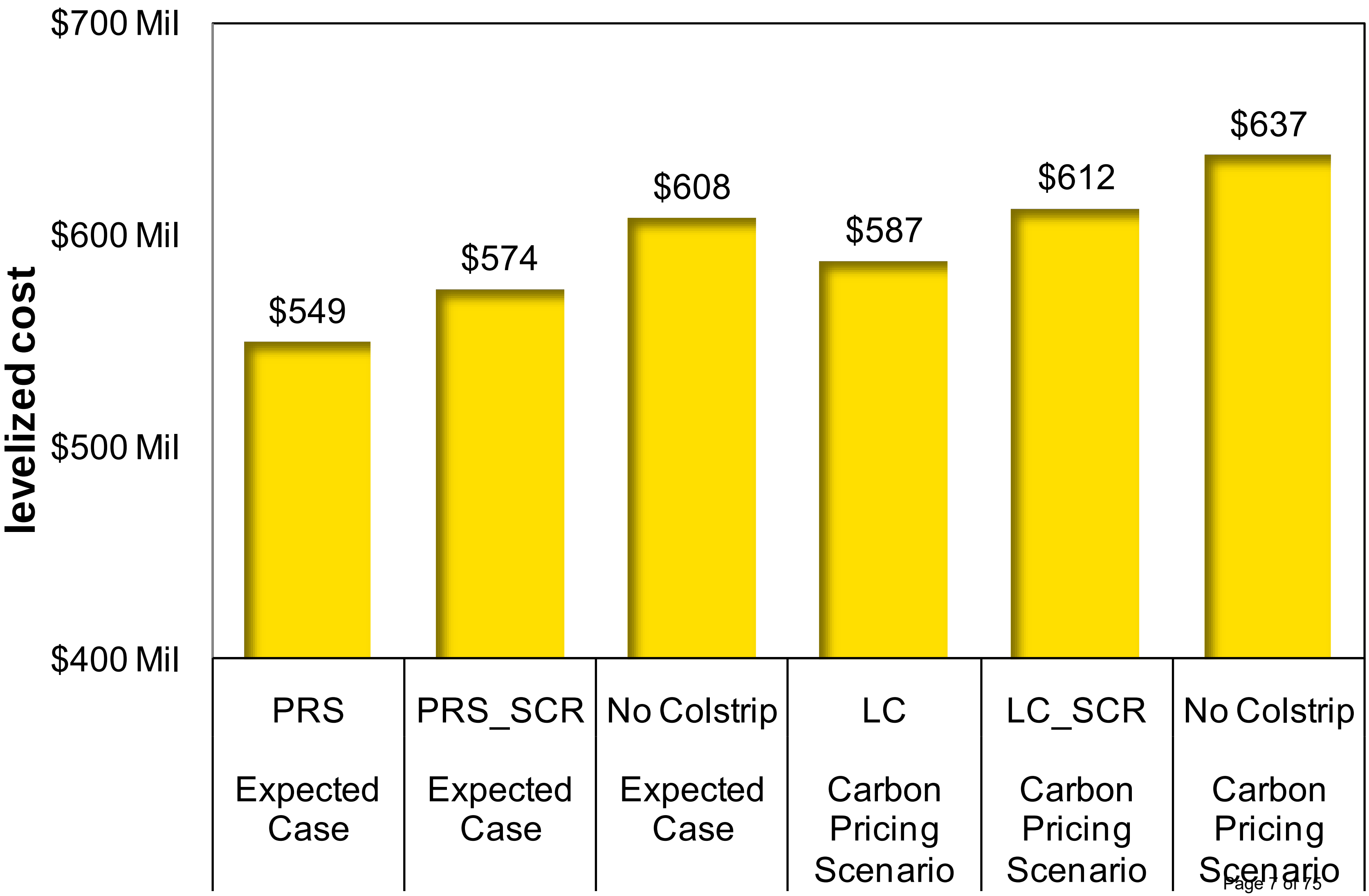


Exhibit JRT-10

Part 1: 2015 Avista Electric IRP Excerpts

Load forecast changes can also come in the form of new large loads or the loss of an existing large load. In both cases, the change will likely be short notice. Avista likely would meet these events by utilizing the energy market.

Colstrip Retirement Scenarios

The 2013 IRP acknowledgement letter from the Washington Commission (Docket UE-121421) requested Avista continue assessing the impacts of a hypothetical portfolio without Colstrip and provide the overall impacts on rates. TAC members requested another scenario to analyze higher operating costs and shorter EPA compliance timelines. Avista evaluated both continued operation and retirement of Colstrip under each of these scenarios.

Modeling results for Colstrip in the Expected Case indicate Avista ownership interests in the plant will remain cost effective for the next 20 years. The IRP assumes certain capital investments will satisfy future state and federal regulations over the IRP timeframe. The type, amount, and timing of capital expenditures are estimates used for modeling purposes because exact dates and costs are unknown at this time. Future IRPs will update assumptions as more and better information is available. The potential capital investments include emerging requirements related to coal combustion residuals (CCR) and Regional Haze-related controls. Other environmental regulations may drive future investment requirements, such as ash pond improvements and the installation of a system for NO_X control. IRP modeling assumes that a default control system of a selective catalytic reduction (SCR) will be required by the end of 2026, but the specific target date or control type is unknown at this time.

Colstrip Retires in 2026 Scenario

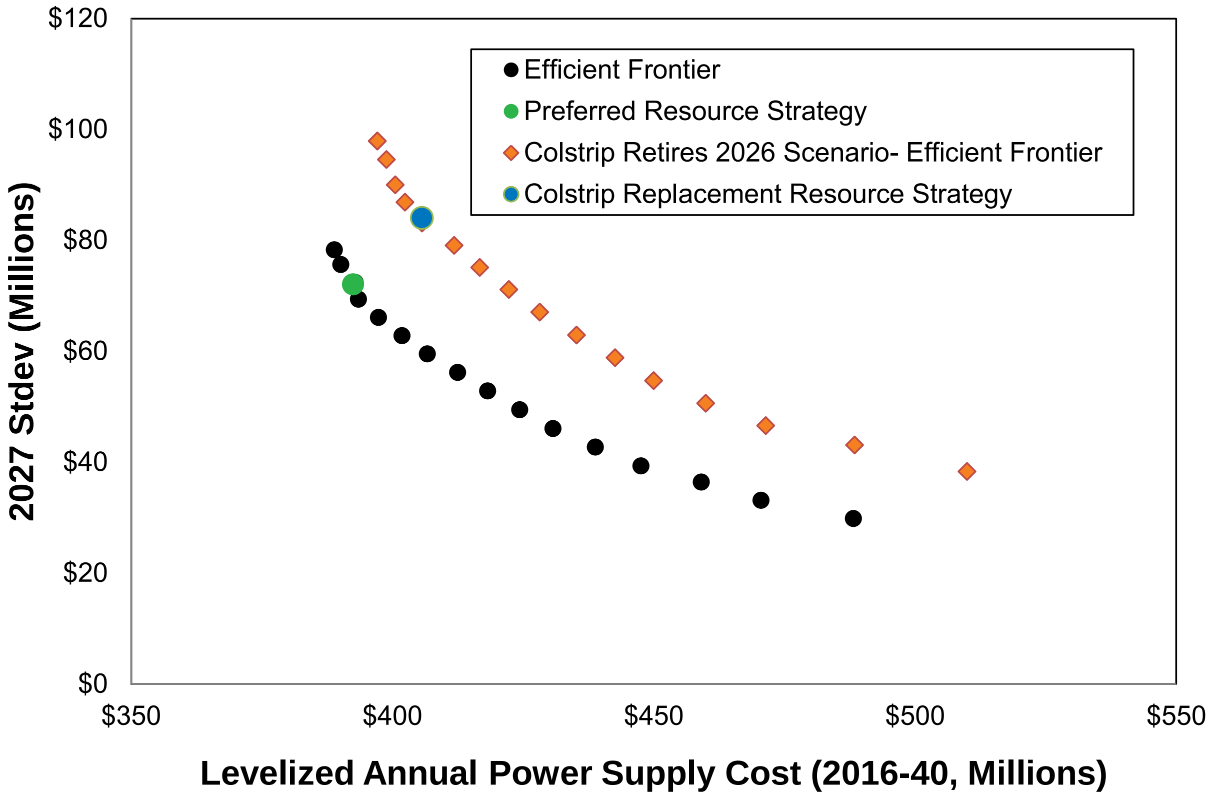
This scenario assumes plant closure at the end of 2026 under the Expected Case's market forecast. This closure date eliminates capital spending for the SCR, accelerates ash pond decommissioning, and alters ongoing capital and O&M spending at the plant. This scenario assumes all costs related to existing and future capital spending would fully depreciate five years after closure. It also assumes capital spending for ash pond closure and no additional shutdown costs beyond the amount included in current depreciation schedules for the plant. The scenario does not include any costs related to employee retraining or relocation costs, payments to other owners, or costs to decommission the plant beyond those included in current rates.

The results of the 2026 year-end closure scenario require 208 MW of new winter capacity, assuming a replacement resource in Avista's balancing area. Table 12.4 provides details about the resource strategy in this scenario. The strategy for this scenario adds a second CCCT to replace the Colstrip capacity and serve future load growth. Figure 12.2 shows a full efficient frontier analysis for this scenario. Levelized power supply costs increase by $13.2 million or 3.6 percent per year across all years of the IRP study. Portfolio risk increases by $12 million in 2027, or 16.6 percent. While the 3.6 percent cost impact appears to be modest due to the IRP's method of levelizing large future costs across the 20-year study timeframe, the annual cost increases in Figure 12.3 are significant beginning in 2027.

Table 12.4: Colstrip Retires in 2026 Scenario Resource Strategy

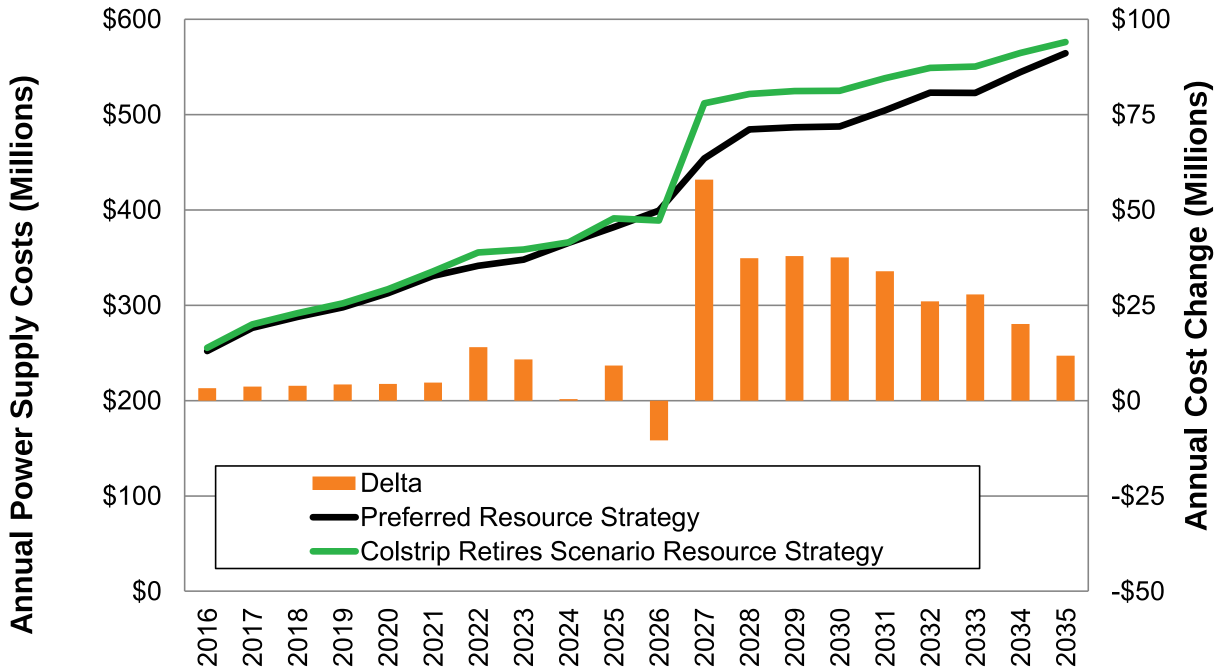
Resource	By End of Year	ISO Conditions (MW)
Natural Gas-Fired Peaker	2020	96
Thermal Upgrades	2021-2025	38
Natural Gas-Fired CCCTs	2026	627
Total		**761**
Conservation (w/ T&D losses)	2016-2035	130.7

Figure 12.2: Colstrip Retires Scenario Efficient Frontier Analysis



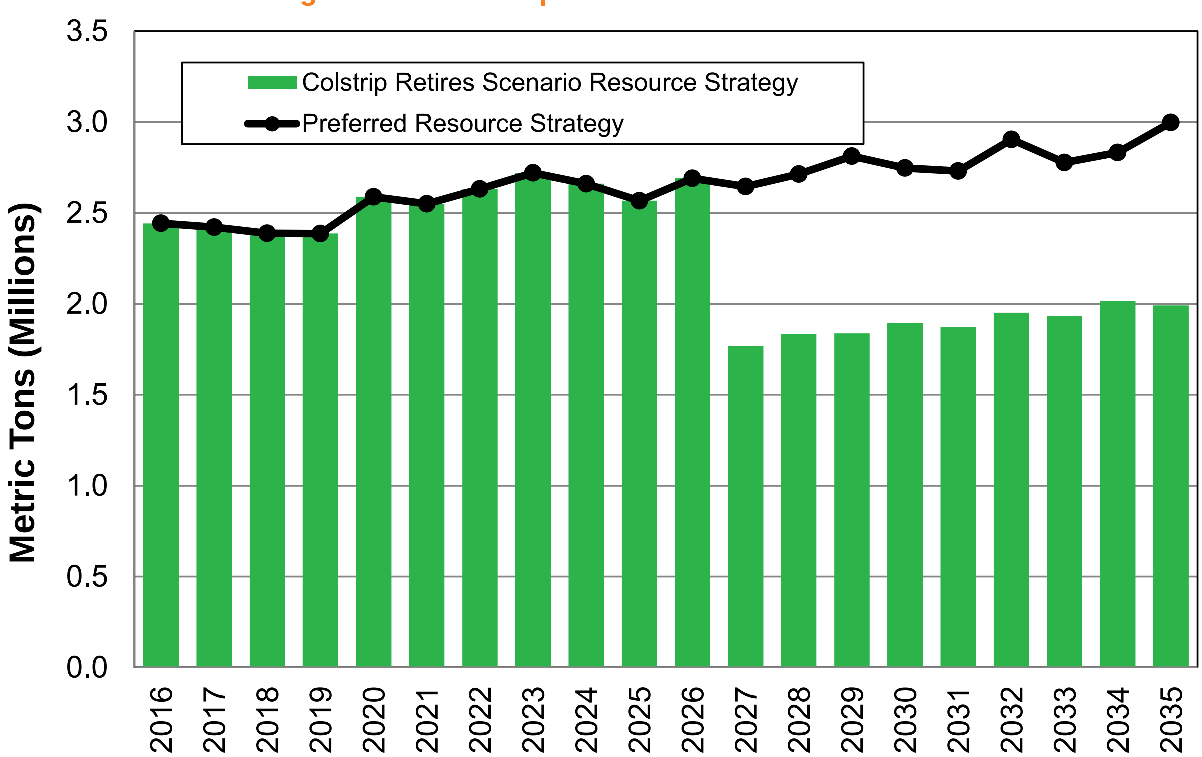
Between 2016 and 2021, customer costs increase due to accelerated recovery of existing capital investments in the plant. In 2022-2026, the model assumes spending to maintain and improve the plant continues at a lower rate, but most costs typically classified as capital spending are expensed, leading to an earlier recovery of spending. The elimination of the SCR offsets and lowers recovered Colstrip costs as high cost investments are removed. The biggest cost to customers is replacement capacity. In 2027, this amounts to $58 million in added costs, or 13 percent. To put this into perspective, Avista's 2015 electric revenue requirement in that year is $900 million. Assuming non-power supply costs increased at the rate of load growth, closing Colstrip alone would increase customer rates by 5.7 percent the first year of closure.

Figure 12.3: Colstrip Retires in 2026 Scenario Power Supply Cost Impact



Avista greenhouse gas emissions decline by an estimated 0.9 million metric tons per year, or 32 percent. Figure 12.4 shows the change in emissions by year. In 2027, the first year of closure in the scenario, the cost per saved metric ton of carbon is $66.

Figure 12.4: Colstrip Retires in 2027 Emissions



High-Cost Colstrip Retention Scenario

The TAC proposed a second Colstrip case. The High-Cost Colstrip Retention scenario assumes replacing existing SO_2 scrubbers, converting the plant to dry ash handling, landfill replacement, acceleration of SCR installation to 2022, and added O&M costs due to the assumed closure of Colstrip Units 1 and 2 in 2017. While offering to perform an analysis of High-Cost Colstrip Retention, Avista does not believe this scenario represents a likely future for Colstrip and therefore has not vetted these assumptions closely. The scenario provides a very high and unlikely case to test the viability of the plant under much higher costs. A third scenario evaluates closing the plant in 2022 to avoid the higher ongoing costs associated with the High-Cost Colstrip Retention case. The resource strategy selected by PRiSM for this scenario is in Table 12.5; it is very similar to the portfolio scenario with the plant retiring in 2027, but the scenario offsets other plant requirements differently causing a small increase in capacity need (770 MW versus 761 MW).

The High-Cost Colstrip scenario in Figure 12.5 uses the efficient frontier methodology to measure cost and risk. It increases fixed costs by $18 million per year levelized between 2016 and 2040 and risk levels do not change. Where Colstrip retires in 2022 to avoid High-Cost Colstrip Retention costs, overall system cost increases $2 million per year; risk increases by $11 million in 2027. The annual costs for the Colstrip scenarios are in Figure 12.6 in 2023. The first year without Colstrip costs increase by $19 million compared to the plant operating with the higher costs. This scenario shows with higher operating costs, the plant is still marginally economic to continue operating.

Table 12.5: Colstrip Retires in 2022 Scenario Resource Strategy

Resource	By End of Year	ISO Conditions (MW)
Natural Gas Peaker	2020	56
Thermal Upgrades	2021-2035	41
Combined Cycle CTs	2023-2026	627
Natural Gas Peaker	2035	47
Total		**770**
Conservation (w/ T&D losses)	2016-2035	131

Figure 12.5: High-Cost Colstrip Retention Scenario Efficient Frontier

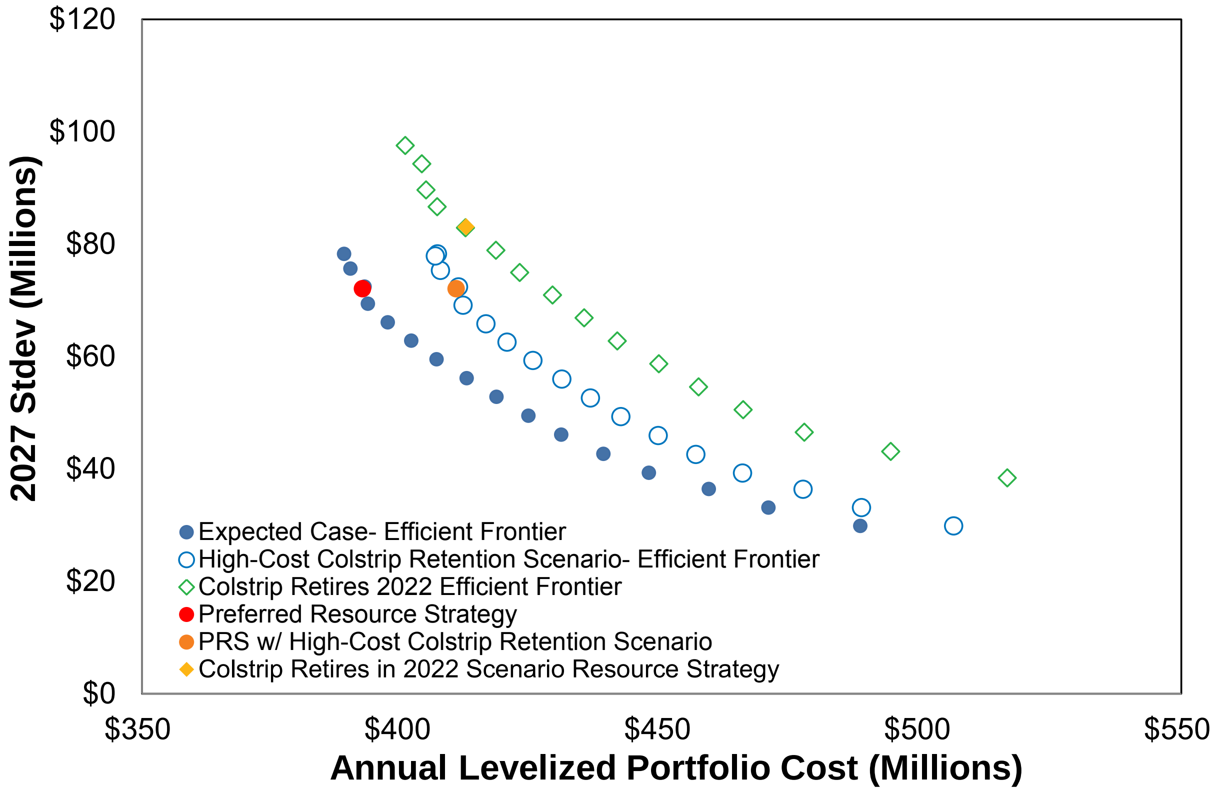
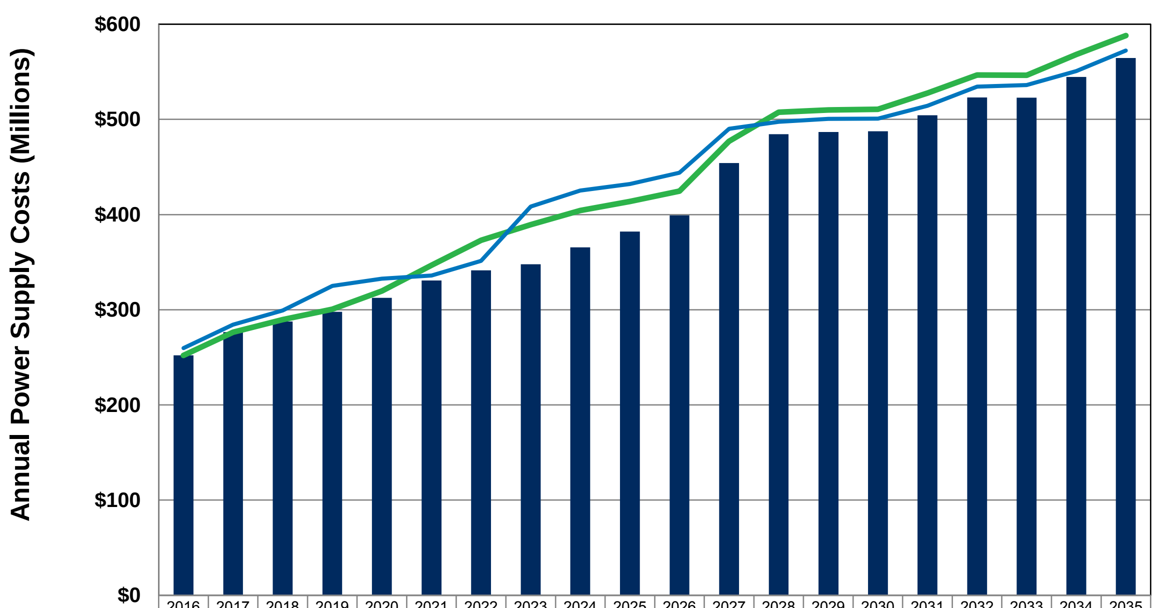


Figure 12.6: High-Cost Colstrip Scenarios Annual Cost



	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
PRS	252	276	288	298	313	331	341	348	366	382	399	454	484	487	488	504	523	523	545	564
PRS High Colstrip Costs	252	276	290	301	320	347	373	389	404	414	425	477	507	510	511	528	547	546	568	588
PRS Colstrip Retires 2022	260	284	299	325	333	336	351	408	425	432	444	490	498	500	501	514	534	536	551	572

Issues Related to Colstrip in this IRP

Modeling Assumptions:

- Greenhouse gas regulations:
  - emissions performance standards (CA, OR and WA)
  - 30% WECC-wide reduction identified pursuant to 111(d)
- National Ambient Air Quality Standards
- Mercury and Air Toxics Rule (HAPs)
- Regional Haze

Emerging Issues:

- Finalization of the 111(d) rule at the federal and state levels
- Coal combustion residuals
- Washington Executive Order 14-04
- Cost of closing the plant and continued use of the site

Colstrip Modeling in the 2015 IRP

Expected Case Assumptions:

- Assumes compliance with known environmental regulations (discussed in the previous slide)
- Expected Case assumptions do not speculate – alternatives considered under futures/scenarios studies
- Colstrip Units #3 – 4 in service through IRP modeling period
- Cost of carbon (to be discussed in the next presentation)

Draft Alternative Colstrip Scenarios:

- SCR on units 3 and 4 in 2025 and 2026
- No SCR, shut down units 3 and 4 by end of 2026

DRAFT

SCENARIO: High-Cost Colstrip Retention

- Higher-cost Colstrip compliance assumptions provided by TAC members
  - Assumptions include:
    - SO_2 Scrubbers: $700 million (2022) w/ $45 million annual O&M
    - Dry Ash Handling Conversion: $60 million (2022) w/ $3 million annual O&M
    - Replacement Landfill: $9 million (2022) w/ $0.33 million annual O&M
    - New SCR: $268 million (2022) w/ $35 million annual O&M
    - Colstrip 1 & 2 retire in 2017, w/ common costs shifted to 3 & 4 owners
- Assumptions have not been vetted by Avista
- Two scenarios studied
  - PRS with higher compliance costs
  - Colstrip retirement at the end of 2022

Exhibit JRT-10

Part 1: 2017 Avista Electric IRP Excerpts

requiring a different decision date for a new facility; the only major difference is the size of the addition. Near the 2026 requirement, Avista will have a greater understanding of its actual requirements.

Table 12.2: Resource Selection for Load Forecast Scenarios

Resource	Expected Case's PRS	High Load Growth	Low Load Growth
NG Peaker	335	477	192
NG Combined Cycle CT	0	0	0
Wind	0	0	0
Solar	0	0	0
Demand Response	49	49	49
Storage	5	0	0
Thermal Upgrades	34	34	34
Hydro Upgrades	0	0	0
Total	**423**	**560**	**275**

Colstrip Scenarios

Coal-fired power plants are facing pressure from both policy requirements and economics to reduce their dispatch or to shut down. Avista's TAC and state commissions asked Avista to study the impacts of shuttering Colstrip prior to the end of its operating life. This IRP studies two alternative shutdown scenarios including coal-fired plant dispatch is limited due to more restrictive carbon reduction policies relative to the Expected Case's assumption.

In the Expected Case, Avista's ownership interests in the plant remains cost effective for the next 20 years, although it dispatches less due to carbon regulation projections. The Expected Case also includes Selective Catalytic Reduction (SCR) beginning service in 2028, significant capital expenses for Coal Combustion Residual (CCR) requirements and water management issues. Operating costs will increase when Units 1 & 2 close because there will be additional O&M costs and possible requirements for additional mercury controls.

Colstrip Retirement Scenario

This IRP includes two scenarios with Colstrip retiring in 2030 and 2035. Both represent plausible early retirement dates when the plant could end service to customers. These scenarios assume both closure dates eliminate capital spending for the SCR and shorten capital recovery to current and future capital to five years after the retirement date. Future capital costs are lower than the Expected Case as certain capital improvements are cancelled. The CCR costs remain the same as in the Expected Case, but the time to complete the projects accelerates. The scenarios do not include costs related to employee retraining or relocation, payments to other owners, or decommissioning beyond those already included rates.

High-Cost Colstrip Retention Scenario

As part of the acceptance letter from the 2015 IRP, the Washington Commission requested a scenario with a higher than expected compliance costs to retain Colstrip and consult with the TAC regarding carbon pricing policies in the stochastic model. This scenario includes the following assumptions:

1) The SCR is required by the end of 2023 instead of 2028 to reflect an expansion of EPA regional air quality programs.
2) Units 1 & 2 shut down in 2018 rather than in 2022 and shift common facility costs earlier than in the Expected Case.
3) Adding a fabric filter (baghouse) system to enhance particulate removal by the end of 2023.
4) State of Montana to reduce carbon emissions beginning following the Clean Power Plan's mass based with new sources levels, but delayed until 2024.[3]

The annual cost between 2018 and 2037 is 3.7 percent higher in the High-Cost Colstrip scenario as compared to the PRS. Instead of paying these higher costs, the plant could retire by 2023. Table 12.4 shows the resource strategy for a 2023 Colstrip retirement to avoid the High Cost Colstrip scenario assumptions. Shutting down the plant as compared to the High Colstrip Cost scenario would save customers 0.35 percent over running the plant for the remainder of the IRP study period. Figure 12.4 illustrates the cost and risk of the portfolio compared to the PRS and the Expected Case's Efficient Frontier. Both the high cost and retirement scenarios result in higher customer costs, but early retirement exposes customers to more volatile power supply costs. Figure 12.5 shows the annual costs of the two scenarios compared to the PRS. Direct emissions for the PRS and the 2023 shutdown case are in Figure 12.6. Early retirement reduces emissions to 0.9 million metric tons if natural gas-fired peakers replace Colstrip and Lancaster and the wholesale market serves some customer energy needs. The implied carbon cost of shutting down the plant between 2024 and 2037 by selecting the new resource strategy is an additional $12.21 per metric ton using the change in cost and the change in Avista's direct emissions from this scenario. This in total with the pricing included in the market analysis, totals $23.88 per metric ton.

[3] The average shadow price of the stochastic studies is $11.67 per metric ton between 2024 and 2037. $6.47 in 2024 and $26.89 in 2037. The 95th percentile price in in 2024 is $16.94 per metric ton and $60.16 in 2037.

Table 12.4: Colstrip Retires in 2023 Scenario Resource Strategy

Resource	By End of Year	ISO Conditions (MW)
Natural Gas Peaker	2023	143
Thermal Upgrades	2023-2037	34
Natural Gas Peaker	2026	288
Natural Gas Peaker	2030	96
Storage	2035	5
Total		**566**
Demand Response	2025-2037	44
Conservation (w/ T&D losses)	2018-2037	107

Figure 12.2: High-Cost Colstrip Retention Scenario Efficient Frontier

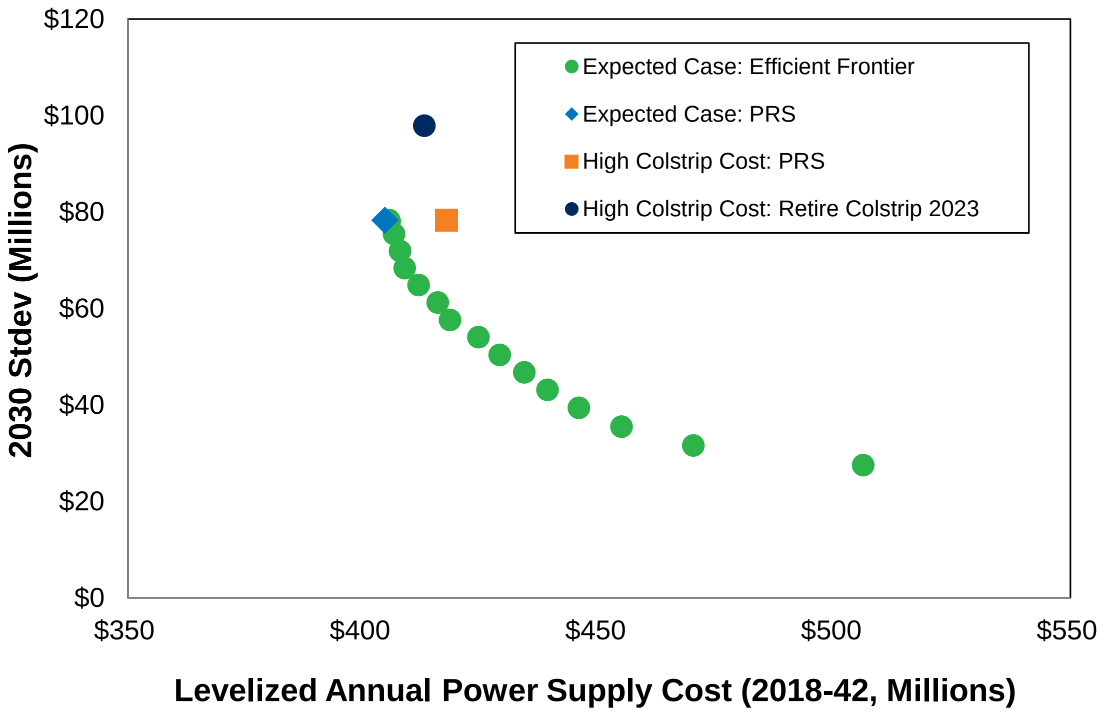


Figure 12.3: High-Cost Colstrip Scenarios Annual Cost

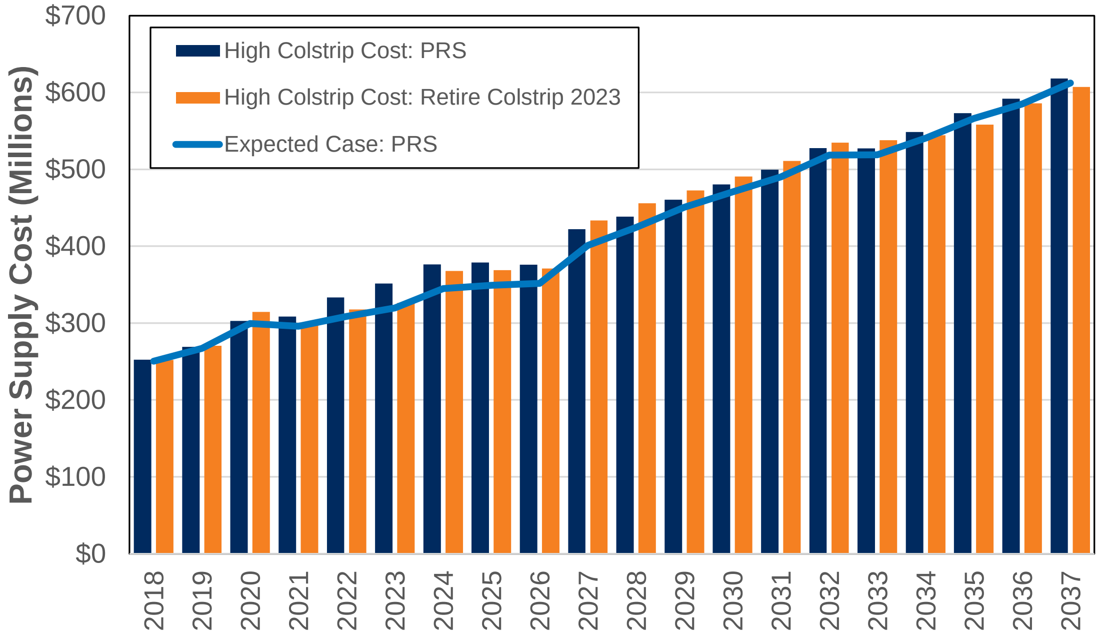
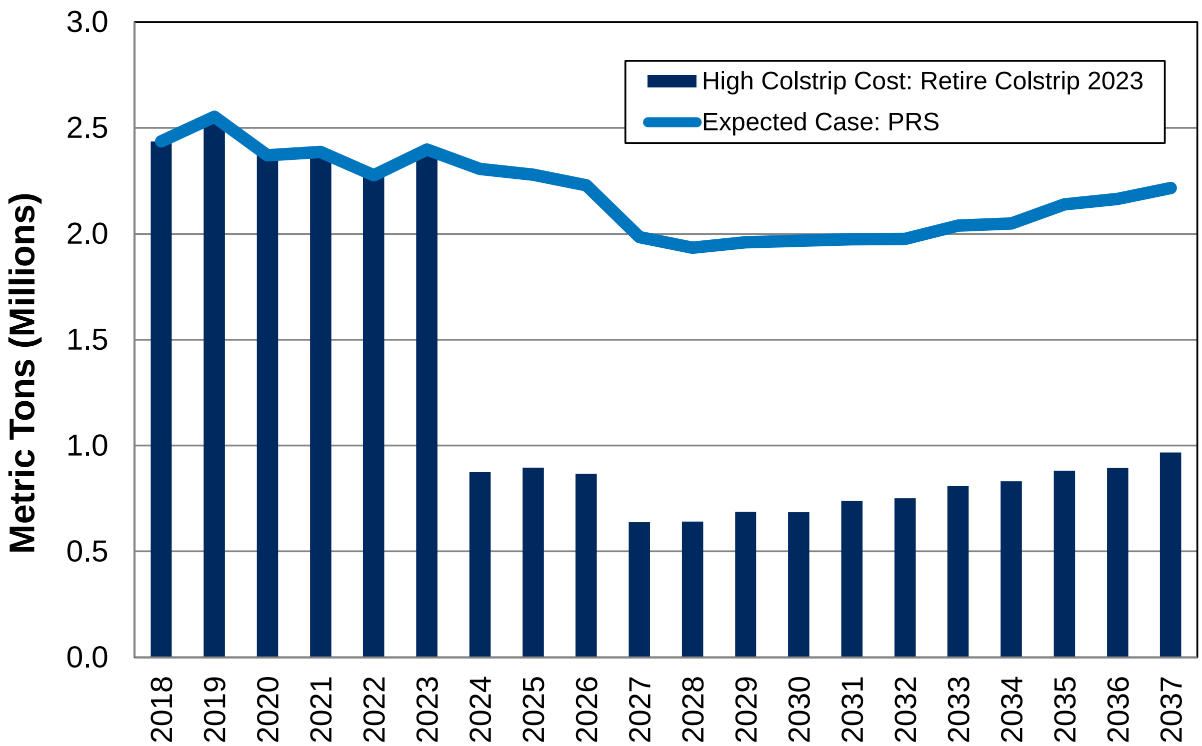


Figure 12.4: Greenhouse Gas Emissions: Retire Colstrip in 2023 versus PRS



Colstrip Expected Case Assumptions

- Avista's share of fuel, O&M, and capital investment costs
- Increased common costs due to shut down of units 1 & 2
- Selective catalytic reduction (SCR) – 2029, includes capital costs, ammonia and fixed and variable O&M to reduce NO_x
- Enhanced mercury controls
- Coal Combustion Residuals (CCR's)
  - Coal dry ash handling (2022) and long term storage
- Smart Burn combustion controls installed in 2017
- Water management
- Depreciation schedule extends beyond 20-year plan horizon

Colstrip Retirement Scenarios

Shows how Avista’s future portfolio could change if Colstrip Units #3 and #4 close early

- Scenario 1: Retire Colstrip Units #3 and #4 in 2030 as alternative to SCR investment
- Scenario 2: Retire Colstrip Units #3 and #4 in 2035 to coincide with state of Oregon legislation and assumes no SCR investment
- Both of these cases assume the closure of Colstrip Units #1 and #2 by July 2022 to coincide with the agreements with the owners of those units

High Colstrip Case

- This case answers the question posed by the Washington Commission in the 2015 IRP acknowledgement letter about several higher cost issues impacting Colstrip's compliance cost
- This scenario assumes:
  - Expected case assumptions, except:
  - EPA expands regional air quality programs and rules to the western U.S. such as CASPR and NAAQS requiring SCR installation on Units #3 and #4 at an earlier date **(End of 2023)**
  - Units #1 and #2 shut down earlier than announced, increasing the amount of shared costs cover by Units #3 and #4 **(End of 2018)**
  - MACT PM/MATS RTR compliance problems. Dry system required to remove particulates and reduce water use **(End of 2023)**
  - No enhancement to existing SO_2 scrubbers as no current regulation drives reduction levels beyond current plant emissions

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Shows how Avista's future portfolio could change if Colstrip Units #3 and #4 close early

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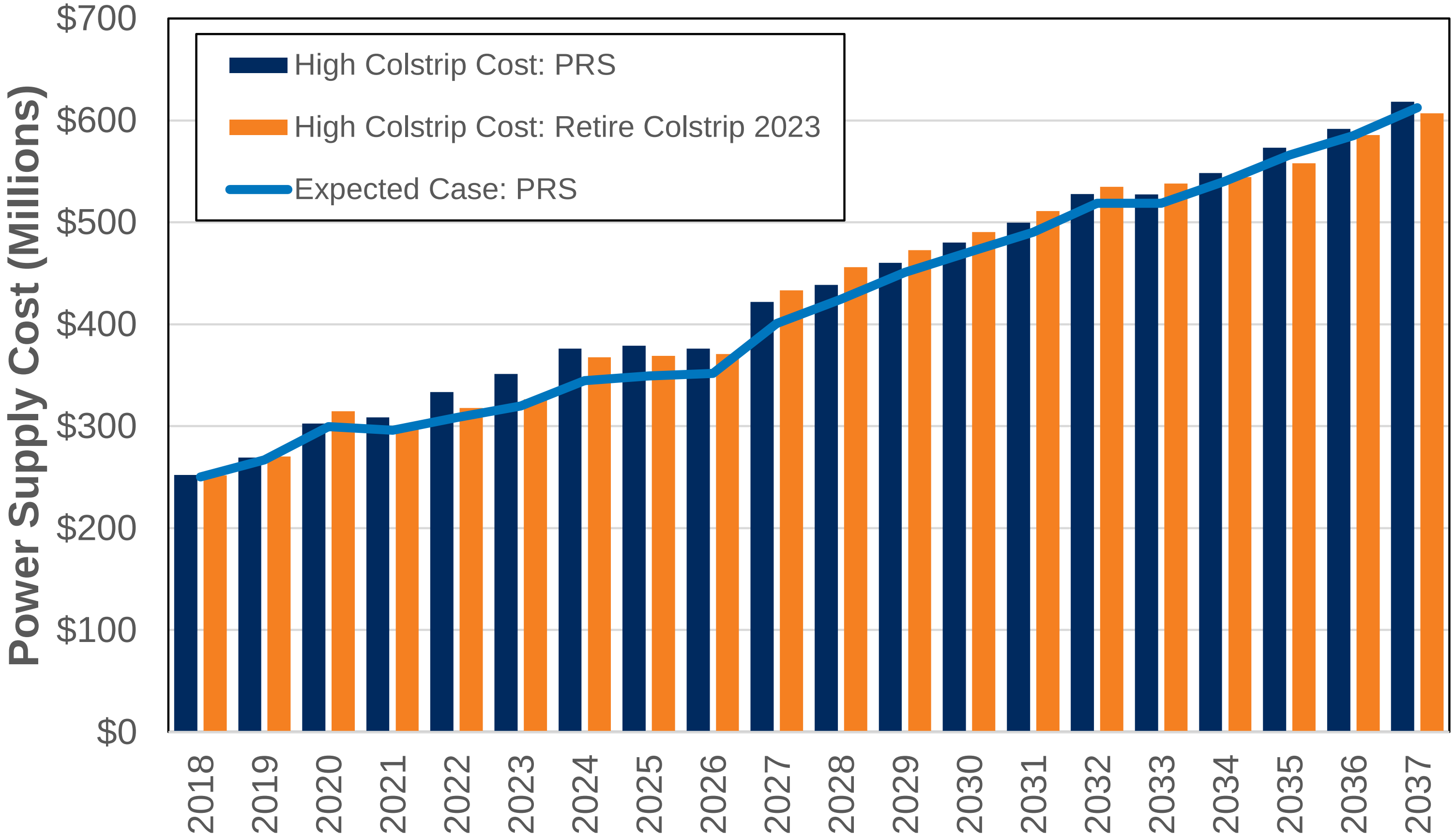
  - MACT PM/MATS RTR compliance problems. Dry system required to remove particulates and reduce water use **(End of 2023)**
  - No enhancement to existing SO_2 scrubbers as no current regulation drives reduction levels beyond current plant emissions

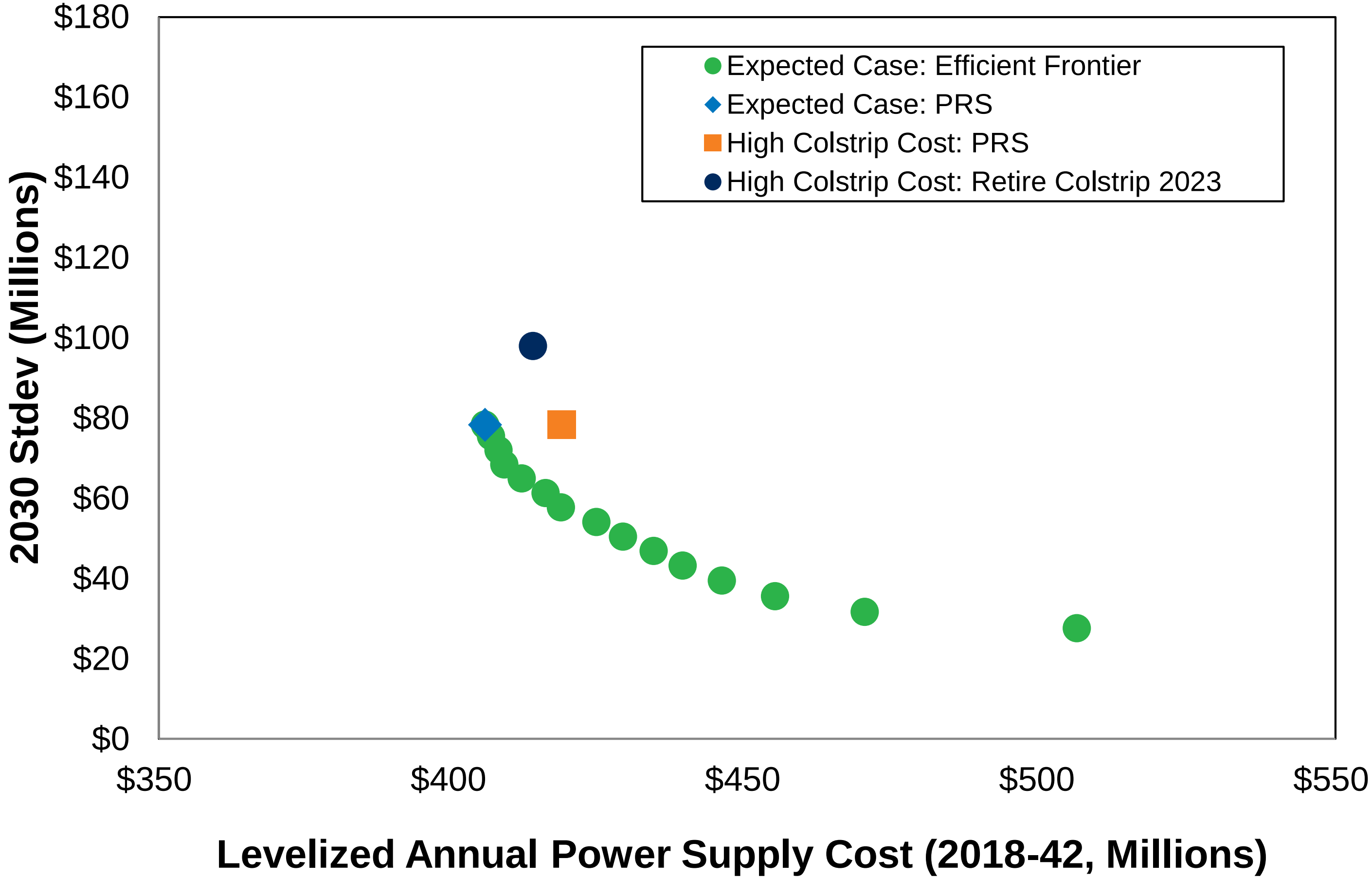
Colstrip High Cost Scenario- Power Sup. Costs

High cost scenario's power supply cost is 4% higher than Expected Case



High Cost Colstrip Scenario: Efficient Frontier

Retiring Colstrip is lower cost, but higher power supply cost risk



High Colstrip Cost Scenario LC Portfolio

Colstrip Retiring in 2023 is LC portfolio to avoid high compliance costs

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Natural Gas Peaker	2026	288
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Demand Response	2025-2037	44
Conservation (w/ T&D losses)	2018-2037	107

Exhibit JRT-10

Part 2: Four Factor Analysis

TALEN MONTANA

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

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

REASONABLE PROGRESS FOUR FACTOR ANALYSIS

Prepared By:

TALEN MONTANA, LLC
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Suite 350
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(720) 638-7647

September 2019

Environmental solutions delivered uncommonly well

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1. EXECUTIVE SUMMARY

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

- <u>Selective Noncatalytic Reduction (SNCR):</u> 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.

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[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

- Selective Catalytic Reduction (SCR): 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.

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2. INTRODUCTION AND BACKGROUND

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.

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[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.

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[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.

3. SOURCE DESCRIPTION

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.

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[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).

4. EXISTING EMISSIONS

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		

5. NO_X FOUR FACTOR EVALUATION

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.

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[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.

6. SO_2 FOUR FACTOR EVALUATION

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.

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[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. SO_2 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.

APPENDIX A NO_X CONTROL COST CALCULATIONS

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
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*

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/.)

* 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) =	2116x[(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.

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} x Q_B x NSR x MW_R)/(MW_{NOx} x 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} x 7.4805)/Reagent Density =	122.9	gal/hour
Estimated tank volume for reagent storage =	(m_{sol} x 7.4805 x $t_{storage}$ x 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 x NOx_{in} x NSR x Q_B)/NPHR =	44.8	kW/hour
Water Usage: Water consumption (q_w) =	(m_{sol}/Density of water) x ((C_{stored}/C_{inj}) - 1) =	0	gallons/hour
Fuel Data: Additional Fuel required to evaporate water in injected reagent (ΔFuel) =	Hv x $m_{reagent}$ x ((1/C_{inj})-1) =	0.52	MMBtu/hour
Ash Disposal: Additional ash produced due to increased fuel consumption (Δash) =	(Δfuel x %Ash x $1x10^6$)/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:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

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 x TCI =	$266,263	in 2018 dollars
Annual Reagent Cost =	q_{sol} x $Cost_{reag}$ x t_{op} =	$1,333,398	in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$10,575	in 2018 dollars
Annual Water Cost =	q_{water} x $Cost_{water}$ x t_{op} =	$0	in 2018 dollars
Additional Fuel Cost =	ΔFuel x $Cost_{fuel}$ x t_{op} =	$6,484	in 2018 dollars
Additional Ash Cost =	ΔAsh x $Cost_{ash}$ x t_{op} x (1/2000) =	$1,007	in 2018 dollars
Maintenance Cleanings* =	4 x $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 x Annual Maintenance Cost =	$7,988	in 2018 dollars
Capital Recovery Costs (CR)=	CRF x 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

What type of fuel does the unit burn? Coal

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

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:

Parameter	Value	Units
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.

Parameter	Value	Units
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

Parameter	Value	Units
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.

Parameter	Value	Units
Gas temperature at the SCR inlet (T)	650	^oF
Base case fuel gas volumetric flow rate factor (Q_{fuel})	516	ft^3/min-MMBtu/hour

Parameter	Value	Units
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

*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

Select the reagent used: Urea

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 Slipadj 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}) =	$m_{reagent}$/Csol =	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:

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

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 x TCI =	$1,554,731 in 2018 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$1,331,849 in 2018 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$1,056,584 in 2018 dollars
Annual Catalyst Replacement Cost =		$2,404,257 in 2018 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 2 selected.
Method 2 (for coal-fired utility boilers):	B_{MW} x 0.4 x $(CoalF)^{2.9}$ x $(NRF)^{0.71}$ x ($CC_{replace}$) x 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 x (Operator Cost + 0.4 x Annual Maintenance Cost) =	$21,285 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x 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

APPENDIX B NO_X RBLC SEARCH RESULTS

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

APPENDIX C SO_2 RBLC SEARCH RESULTS

Table D-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 D-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 D-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