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STATE OF MISSOURI

MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of Union Electric Company	)	
d/b/a Ameren Missouri's Tariffs to Adjust	)	File No. ER-2022-0337
its Revenues for Electric Service	)	

Direct Testimony

of

Tyler Comings

On Behalf of
Sierra Club

PUBLIC VERSION

January 10, 2023

BEFORE THE
MISSOURI PUBLIC SERVICE COMMISSION

In the Matter of Union Electric Company d/b/a Ameren Missouri's Tariffs to Adjust its Revenues for Electric Service	)))	File No. ER-2022-0337

AFFIDAVIT

Pursuant to Missouri Public Service Commission requirements I, Tyler Comings, hereby state:

1. My name is Tyler Comings and I am a Senior Researcher at Applied Economics Clinic. My business address is 1012 Massachusetts Avenue, Arlington, Massachusetts 02476.
2. Attached hereto and made part hereof for all purposes is my Direct Testimony on behalf of Sierra Club, including exhibits, which have been prepared in written form for introduction into evidence in the above-referenced docket.
3. I hereby swear and affirm that based upon my personal knowledge, the facts stated in the Direct Testimony are true. In addition, my judgement is based on my professional experience, and the opinions and conclusions stated in the testimony are true, valid, and accurate.

Under penalty of perjury, I declare that the preceding to be true and correct to the best of my knowledge and belief.

Date: January 10, 2023

Tyler Comings

Tyler Comings

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I. Introduction and Qualifications

Q. Please state your name, business address, and position.

A. My name is Tyler Comings. I am a Senior Researcher at Applied Economics Clinic, located at 1012 Massachusetts Avenue, Arlington, Massachusetts.

Q. Please describe Applied Economics Clinic.

A. The Applied Economics Clinic is a 501(c)(3) non-profit consulting group. Founded in February 2017, the Clinic provides expert testimony, analysis, modeling, policy briefs, and reports for public interest groups on the topics of energy, environment, consumer protection, and equity, while providing on-the-job training to a new generation of technical experts.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of Sierra Club.

Q. Please summarize your work experience and educational background.

A. I have 17 years of experience in economic research and consulting. At Applied Economics Clinic, I focus on energy system planning, costs of regulatory compliance, wholesale electricity markets, utility finance, and economic impact analyses. I have provided testimony on these topics in Arizona, Colorado, the District of Columbia, Hawaii, Indiana, Kentucky, Maryland, Michigan, Missouri, New Jersey, New Mexico, Ohio, Oklahoma, West Virginia, and Nova Scotia (Canada). I am also a Certified Rate of Return Analyst (CRRA) and member of the Society of Utility and Regulatory Financial Analysts (SURFA).

I have provided expertise for many public-interest clients including: American Association of Retired Persons (AARP), Appalachian Regional Commission, Citizens Action Coalition of Indiana, City of Atlanta, Consumers Union, District of Columbia Office of the People's Counsel, District of Columbia Government, Earthjustice, Energy Future Coalition, Hawaii Division of Consumer Advocacy, Illinois Attorney General, Maryland Office of the People's Counsel, Massachusetts Energy Efficiency Advisory Council, Massachusetts Division of Insurance, Michigan Agency for Energy, Montana Consumer Counsel, Mountain Association for Community Economic Development, Nevada State Office of Energy, New Jersey Division of Rate Counsel, New York State Energy Research and Development, Nova Scotia Utility and Review Board Counsel, Rhode Island Office of Energy Resources, Sierra Club, Southern Environmental Law Center, U.S. Department of Justice, Vermont Department of Public Service, West Virginia Consumer Advocate Division, and Wisconsin Department of Administration.

I was previously employed at Synapse Energy Economics, where I provided expert testimony and reports on coal plant economics and utility system planning. Prior to that, I performed research on consumer finance and behavioral economics at Ideas42 and conducted economic impact and benefit-cost analysis of energy and transportation investments at EDR Group (now EBP).

I hold a B.A. in Mathematics and Economics from Boston University and an M.A. in Economics from Tufts University.

My full resume is attached as Exhibit TC-1.

Q. Have you previously testified before the Missouri Public Service Commission?

A. Yes. I filed testimony on the prudence of Evergy's fuel costs in File Nos. EO-2020-0262 and EO-2020-0263.

Q. Have you co-written comments that were filed before the Missouri Public Service Commission?

A. Yes. I have co-written comments on integrated resource plans (IRPs) filed before this Commission in File Nos. EO-2022-0202, EO-2022-0201, EO-2021-0035, EO-2021-0036, EO-2021-0021, EO-2020-0262, EO-2020-0263, EO-2020-0280, and EO-2020-0281.

Q. What is the purpose of your testimony?

A. My testimony focuses on future cost recovery at the Sioux and Labadie units. I discuss how the capital spending at these units should be evaluated in future rate cases with the potential for earlier retirement in mind. First, I walk through recent historical data and forecasts from the Company on the performance of the Sioux units. Second, I explain why Ameren should evaluate an earlier retirement for these units because of their poor economics and low-cost replacement options. Third, I discuss how the Sioux and Labadie units are vulnerable to current and future regulations that would lead to a near-term retirement or retrofit decision. Finally, I provide a framework for evaluating future capital spending at these units based on whether those costs would be "avoidable" when considering earlier retirement for any of its coal units.

Q. What information did you review in preparing your testimony in this case?

A. I reviewed the Company's testimony, exhibits, workpapers, and discovery responses.

Q. Please summarize your findings and recommendations.

A. Based on my review and analysis, I conclude that:

1. **The Sioux units are costly and unreliable; they should be considered for earlier retirement.** The Sioux units operate infrequently because they have high variable costs and because they are often unavailable for unplanned reasons. The units have a high rate of forced outages, and Ameren expects the likelihood of these failures to increase. The Company currently plans to retire the units in 2030 but given their poor performance and the cost-competitive replacement options available—especially with the recently passed Inflation Reduction Act (IRA)—the units should be considered for retirement earlier than 2030.

2. **The Sioux and Labadie units could soon require costly retrofits soon that would trigger a retirement decision.** In particular, both plants have high nitrogen oxide (NO_x) emissions which are a precursor to ozone and therefore vulnerable to regulations. Most pressing at this time is the EPA's recently proposed Good Neighbor Plan which would further mitigate ozone transport by likely requiring expensive selective catalytic reduction (SCR) controls at these units. There is also Regional Haze that could require SCR or additional sulfur dioxide (SO_2) reductions. At a minimum, the substantial costs of SCR should prompt an economic evaluation of whether to retrofit or retire these units in the near-term.

3. **The Company should identify capital spending that is avoidable with earlier retirement at these units in future rate cases.** In the next five years, the Company plans to spend over **[redacted]**

** [redacted] **.[1] But if any of these units were to retire earlier than currently planned, then there is potential to avoid some of these investments and therefore avoid associated rate increases. The Commission should compel the Company to identify any "avoidable" spending ahead of time so that it can determine whether or not to include these costs in rate base in a future rate case.

II. The Sioux and Labadie Units Should be Considered for an Earlier Retirement.

Q. Please summarize your assessment of the Sioux and Labadie coal units in this case.

A. The Sioux and Labadie coal units should be considered for earlier retirement which could also avoid capital spending in future rate cases. First, the Company's most recent evaluation of the units' lives was flawed and is now already outdated with the extension and augmentation of tax credits now available for clean replacement through the Inflation Reduction Act (IRA). Second, the Sioux units in particular have proven costly and unreliable. They have operated infrequently in recent years because they are often unavailable on a forced outage or too expensive to operate. Ameren's own outlook of fuel costs and availability at these units remains poor.[2] Both the Sioux and Labadie plants are vulnerable to pending environmental regulations, such as the proposed Good Neighbor Rule and updates to Regional Haze, that could require major emission controls. This could lead to a partial or full retirement, or gas conversion of the units.

[1] Comings Workpaper CONFIDENTIAL – Company Response to Sierra Club Data Request 1-11, SIERRA_1-SC_001_11-Att-SC 001.11 Coal CapEx.

[2] Comings Workpaper – Company Response to Sierra Club Data Request 1-2, SIERRA_1-SC_001_2-Att-SC 001.2.

The plans for these units' futures are germane to rate cases because Ameren could avoid future capital spending and associated cost recovery at the units if there was potential for earlier retirement.[3] The Company could identify these "avoidable" costs ahead of time for the Commission to be able to exclude these from rate base, and thus ratepayers would not pay for unnecessary capital spending. Later in my testimony, I describe a framework that the Commission should adopt to achieve this.

A. <u>The Inflation Reduction Act Provides Even Lower-Cost Replacement Options.</u>

Q. What is the Company's current plan for the Sioux units?

A. The Company's last full triennial IRP in 2020 only looked at two potential retirement dates for Sioux in 2028 and 2033.[4] The Company determined that the earlier of the two dates was part of their preferred plan. But the Company recently extended the Sioux retirement from 2028 to 2030 in its 2022 IRP Change report.[5] On behalf of Sierra Club, I co-authored technical comments on the original IRP explaining that Ameren's retirement dates were too limited and that the coal fleet could be subject to more risks through emission control requirements.[6] When the retirement date was extended in the Company's 2022 IRP update, I also co-authored comments explaining why this decision was not justified for many

[3] Throughout, I will refer to ceasing coal operations as "retirement" but acknowledge that conversion to natural gas is also an option (if technically feasible).

[4] Ameren Missouri 2020 IRP, Chapter 9, p. 4.

[5] Ameren Missouri 2022 Change in Preferred Plan, p. 29.

[6] Exhibit TC-3, Sierra Club Comments on Ameren Missouri's 2020 IRP, File No. EO-2021-0021, p.1-2, 15.

reasons.[7] The Company is expected to file its next full IRP later this year and is likely to re-evaluate retirement dates for its coal units in that docket.

Q. What is the Company's current plan for the Labadie units?

A. In the full 2020 triennial IRP, Ameren determined that Labadie units 1 and 2 would retire in 2042 and Labadie units 3 and 4 would retire in 2036; and this plan has not changed since then. Comments that I co-authored on the 2020 IRP and 2022 IRP Change both addressed concerns with regulatory risk at these units.

Q. Did you agree with the Company's rationale for extending the retirement of Sioux from 2028 to 2030 in its latest plan?

A. No. In its 2022 IRP Update, the Company delayed the original Sioux retirement date of 2028 by two years due to a present value revenue requirement (PVRR) analysis and the timing of its ability to install a natural gas combined cycle (NGCC) plant replacement.[8] But the PVRR results were negligible by showing that it was merely 0.03 percent more costly to retire the plant in 2028 instead of 2030. The NGCC replacement was also assumed to be "clean-burning" by 2040 and the Company argued that it was needed for reliability; but both of these claims were unfounded.[9] First, the Company assumed carbon capture and hydrogen would be used at the new gas replacement but the costs associated with adopting these new technologies were not included in its modeling; thus it was

[7] Exhibit TC-3, Sierra Club Comments on Ameren Missouri's 2022 Change in Preferred Plan IRP, File No. EO-2022-0362, p.6-11.

[8] File No. EO-2022-0362, Company data response to SIERRA-SC 005.

[9] Ameren Missouri 2022 Change in Preferred Plan, p. 3, 29.

assumed to transition to being "clean-burning" at no cost.[10] Second, the analysis of reliability presented by the Company was incomplete by only looking at adding new natural gas combined cycles and four-hour batteries, rather than adding combustion turbines and/or longer-duration battery storage.[11]

Q. Are the costs of clean replacement resources more competitive now than when Ameren conducted its 2022 retirement analysis?

A. Yes. The passage of the Inflation Reduction Act (IRA) in August of 2022 is undeniably a significant change to the electric utility industry, in large part by providing substantial federal tax credits for new clean resources—and this was not incorporated in the selection of the 2022 IRP Change preferred plan, which included the 2030 retirement decision for Sioux. The most notable changes to existing tax credits include effectively making the production tax credit (PTC) available for solar PV projects; and making the investment tax credit (ITC) available for standalone battery storage and (after 2024) for wind. In

[10] Exhibit TC-3, Sierra Club Comments on Ameren Missouri's 2022 Change in Preferred Plan IRP, File No. EO-2022-0362, p.10.

[11] Ameren Missouri 2022 Change in Preferred Plan, p. 17-18. When asked in the stakeholder meeting if the Company's contractor, Astrapé, evaluated longer-duration batteries, Ameren said that it looked at 8 and 24-hour batteries as well. But the reliability analysis does not show an analysis of these battery types. The Company also stated that there was no further documentation for the reliability analysis other than what was presented in the 2022 IRP Change report, so any work Astrapé did involving longer-duration batteries is unavailable.

addition, the IRA restored both the ITC[12] and PTC[13] to their previous maximum levels and extended their availability until 2033 (at the earliest[14]) These changes unequivocally make solar, wind, and battery storage more financially appealing for resource planners—and by extension ratepayers.

Using the old tax law (pre-IRA), Ameren only included battery storage in its 2022 IRP Change preferred plan starting in 2035, but standalone batteries are now eligible for a 30 percent ITC through at least 2033 (up to 50 percent depending on location[15] and if using domestic parts). This represents a major industry shift. Battery installations were already increasing rapidly in recent years,[16] and the IRA will only make these a more attractive

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[12] *See* Inflation Reduction Act, Public Law 117-169 *available at* https://www.congress.gov/117/plaws/publ169/PLAW-117publ169.pdf. The IRA addresses two related sections of the Internal Revenue Code: it amends the existing Section 48 (which already authorized the Investment Tax Credit) to address projects commencing construction by 2024, and it also creates the new Section 48E to authorize a new, similar (but not identical) Clean Energy Investment Credit for projects to be placed in service after 2024. I refer to these two programs together as "the ITC."

[13] Inflation Reduction Act, Section 13701 (creating new Section 45Y of the Internal Revenue Code). The IRA creates the Clean Energy Production Credit program which effectively extends the PTC. As with the ITC, I refer to the original PTC and its new successor program collectively as "the PTC."

[14] Inflation Reduction Act, Section 13701 (creating new Section 45Y(d) of the Internal Revenue Code). This phase down will be begin when the US electric sector reaches a greenhouse gas emissions threshold of 25 percent or less of its 2022 emissions, but the credit will remain through 2033 at the earliest. Thus, the years referenced in my sentence above could actually be later.

[15] For example, if Ameren located battery at the site of the retired Meramec coal plant, the battery would be eligible for a 40% ITC.

[16] Vanessa Witte, *US battery storage deployment doubles in a single year*, Wood Mackenzie, (March 24, 2022), *available at* https://www.woodmac.com/news/opinion/us-battery-storage-deployment-doubles-in-a-single-year/.

resource option. EIA expects 20.8 GW of battery storage to be added from 2023 to 2025, with total battery capacity in the U.S. expected to reach 30 GW by 2025.[17].

The IRA also changes the economics of solar through two different avenues. First, the law increases and extends the solar ITC, making solar PV resources with this credit cheaper for at least the next decade. Second, and more importantly, utilities can now use the PTC for solar PV resources instead of the ITC, which will be an even cheaper option for many projects. The current PTC amount allowed by the IRS is $27.50 per MWh.[18] This amount paid for solar generation over a 10-year period means it is likely that many solar developers and utilities will take advantage of this new option instead of the ITC. For instance, the CEO of Ameren Corporation stated that:

> [T]he PTC for solar is a positive versus the prior ITC and transferability provisions, which are things that we really think could help us to pass the value associated with some of these tax credits to our customers more swiftly. Like I said, net, we think that the legislation overall is good and will help facilitate a lower cost transition to this clean energy.[19]

Solar PV resources were the most-installed capacity type in the U.S. in 2021, with 15.5

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[17] U.S. Energy Information Administration (EIA), *U.S. battery storage capacity will increase significantly by 2025*, (December 8, 2022), *available at* https://www.eia.gov/todayinenergy/detail.php?id=54939.

[18] The IRS has recently issued updated guidance that the inflation-adjusted, full credit in calendar year 2022 is $27.50 per MWh (2.75 cents per kWh). *See Renewable Electricity Production Credit Amounts for Calendar Year 2022* https://www.irs.gov/pub/irs-drop/a-22-23.pdf.

[19] Ameren Q2 2022 Earnings Call, p.11, (August 5, 2022), *available at* https://s21.q4cdn.com/448935352/files/doc_financials/2022/q2/Ameren-Corporation-Q2-2022-Earnings-Call-Transcript.pdf.

GW built.[20] With the availability of the PTC, utilities are even more likely to pursue solar as a low-cost replacement resource.

Q. Do these new tax credits in the IRA represent a material change to the industry?

A. Yes. The law offers the most comprehensive and substantial set of incentives for building clean energy resources ever put forward in the U.S. By extension, lower-cost clean replacement resources make existing and new fossil investments less competitive. In recent years, and even prior to these new tax credits, there has already been substantial buildout of clean resources and the IRA incentivizes these replacement resources even further. CenterPoint Energy in Indiana, for example, issued an RFP for a wide variety of supply and demand-side resources on May 11, 2022, where the responses would inform assumptions in its 2022 IRP.[21] The responses to the RFP were originally due on July 5, 2022. But after the IRA became law, the utility agreed to allow bidders to update their submittals. By extension, the modeling for the IRP was delayed in order to accommodate these new bids.[22] The utility reported summary statistics for updated bids that showed marked reductions in costs for storage, wind and solar PPAs.[23]

Due to timing, Ameren did not model the IRA in its 2022 IRP Change but the Company is likely to incorporate the law in its upcoming 2023 IRP. With even lower-cost clean

[20] EIA, *Solar power will account for nearly half of new U.S. electric generating capacity in 2022*, (January 10, 2022), *available at* https://www.eia.gov/todayinenergy/detail.php?id=50818.

[21] CenterPoint Energy, *CenterPoint Energy All-Source RFP,* (May 11, 2022), *available at* http://centerpoint2022asrfp.rfpmanager.biz/.

[22] CenterPoint Energy*, IRP Public Stakeholder Meeting*, Slide 27, (October 11, 2022) *available at* https://midwest.centerpointenergy.com/assets/downloads/planning/irp/IRP-2022-Vectren-Stakeholder-Meeting-2-Redacted.pdf.

[23] *Id.*, Slide 29.

replacement options, there is more economic pressure to retire its coal units—Sioux units in particular given their poor performance (as I explain below). Moreover, given the transformative effect of the IRA, Ameren should evaluate its fleet under this new economic landscape as soon as possible.

Q. How is the retirement year for the coal units relevant in a rate case?

A. The Labadie plant is currently slated to fully retire in 2042 and the Sioux units are slated for 2030 retirement. However, if Ameren does a rigorous retirement analysis that includes the IRA tax credits soon and/or as part of its 2023 IRP, an earlier retirement date is more likely to be favorable, especially for the Sioux units. This matters for future rate cases because planned capital spending should change with the units' retirement year(s). Even the consideration of earlier retirement should lead to a re-evaluation of capital spending. That is because some planned spending may either no longer necessary or no longer cost-effective with a shorter resource life. The identification of avoidable costs is therefore important for the Commission's determination of which costs to include in rate base as reasonable and prudent. Including avoidable costs in rates would prevent ratepayers from realizing this savings should the coal units retired earlier. Later in my testimony, I lay out a framework for addressing avoidable costs in future rate cases.

Q. Is the IRA the only reason that the Sioux and/or Labadie units may retire earlier than currently planned?

A. No. As I explain further in my testimony, there are two other reasons that the Sioux units could retire sooner: 1) the Sioux units have operated poorly in recent years because they are costly and unreliable; and 2) pending ozone regulation, such as the Good Neighbor

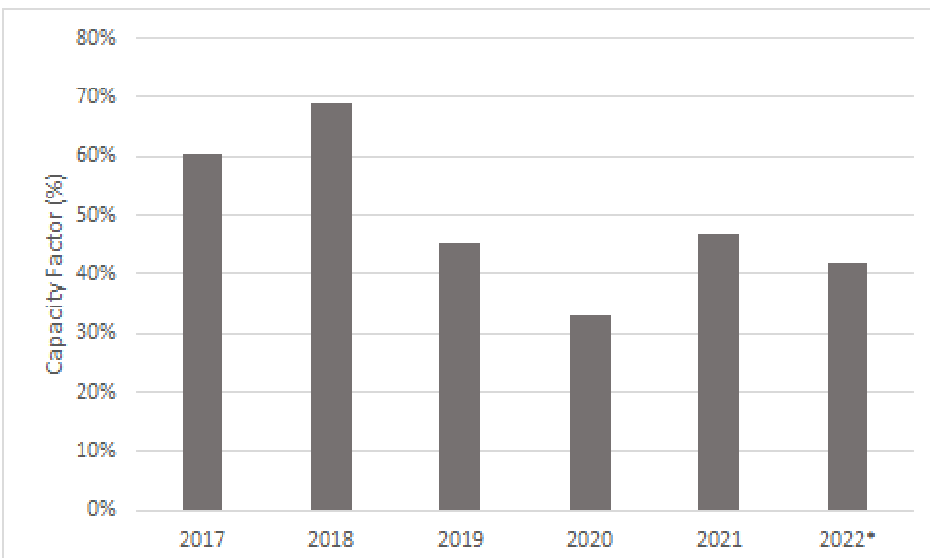
Rule and Regional Haze, could also lead to an earlier retirement by requiring costly emission controls for the Sioux and/or Labadie units.

B. The Sioux Units Are Costly and Unreliable.

Q. Does Sioux operate frequently for a coal plant?

A. No. The plant has operated at a capacity factor below 50 percent since 2019—as shown in Figure 1 below. In 2020, in particular the plant operated at 33 percent—or roughly one third of its potential. This is caused by two main factors: 1) the units are unavailable due to forced outages; and 2) the units are expensive to operate.

Figure 1: Sioux Historical Capacity Factor (%)[24]



[24] Comings Workpaper – Company Response to Sierra Club Data Request 1-1, SIERRA_1-SC_001_1-Att-SC 001.1-e-j-k-l-n-o-s. *2022 data is through August, the latest provided by Ameren.

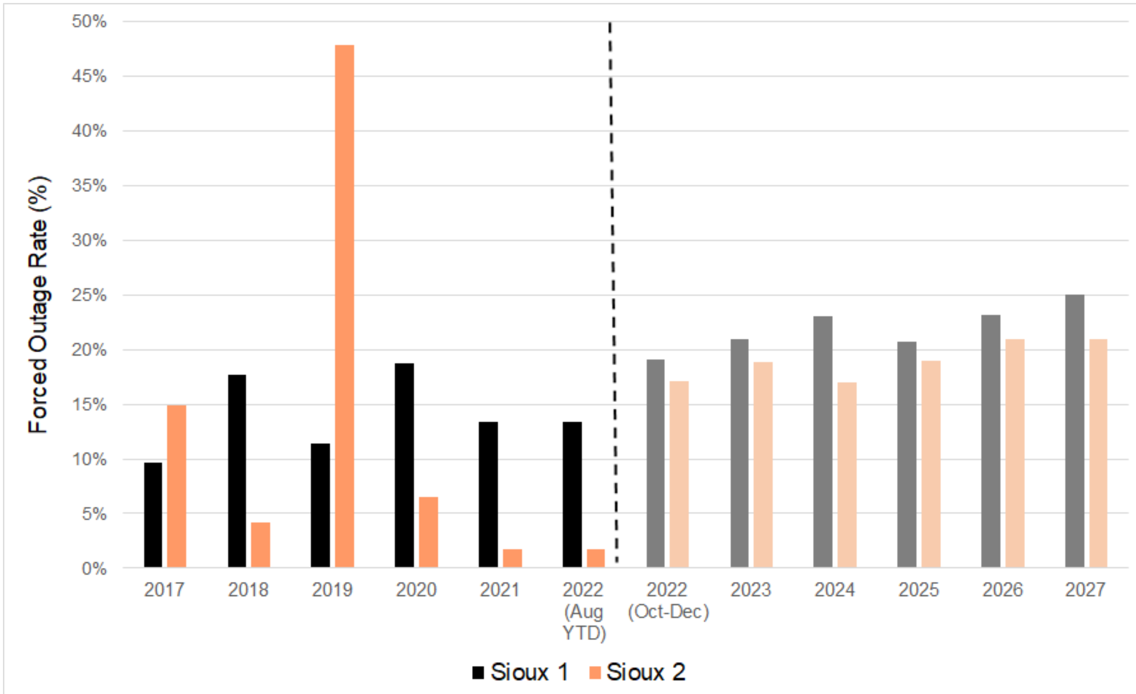
Q. Is the units' availability a consideration when evaluating retirement?

A. Yes. It is axiomatic that a unit cannot generate if it is unavailable; but it also means the unit is less reliable as a capacity resource. The two Sioux units have had high amounts of forced outages in the past and according to Ameren, the units are both expected to be out for between 17 and 25 percent of the time.[25] The availability of the units affects both the energy and capacity value of the units in several respects: 1) the energy value will decrease as availability decreases (i.e., outages increase) because the units cannot generate when unavailable; 2) the capacity value will decrease as availability decreases because the units are less dependable during peak hours. The units' capacity that is credited by MISO are based on unforced capacity (UCAP), which discounts a unit's capacity based on its past propensity for forced outages.

Sioux units 1 and 2 have had high forced outage rates in previous years, meaning that they have been less frequently available for unplanned reasons. The Company anticipates even higher typical forced outage rates through 2027 (the latest year provided)—as shown in Figure 2 below.

[25] Comings Workpaper – Company Response to Sierra Club Data Request 1-2, SIERRA_1-SC_001_2-Att-SC 001.2.

Figure 2: Forced Outage Rates for Sioux units 1 and 2[26]



Q. Have the recent forced outages affected the credited capacity at these units?

A. Yes. The units are assumed to be much less reliable for meeting summer peak demand than a few years ago. Since 2019, the UCAP value for Sioux unit 1 has decreased by 11 percent and by 15 percent for Sioux 2.[27] Therefore, these units' contribution to the Company's capacity requirement by MISO has deteriorated significantly because of their lack of availability. With the Company's expectations of forced outages at these units, the UCAP value will continue to decrease in the future.

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[26] Comings Workpaper – Company Response to Sierra Club Data Request 1-1, SIERRA_1-SC_001_1-Att-SC001.1-p-q-r; Company Response to Sierra Club Data Request 1-2, SIERRA_1-SC_001_2-Att-SC 001.2.

[27] Comings Workpaper – Company Response to Sierra Club Data Request 1-1, SIERRA_1-SC_001_1-Att-SC 001.1-g.xlsx.

Q. Have the Sioux units' fuel costs increased ** [redacted] ****?**

A. Yes. The Sioux units' fuel costs have increased significantly ** [redacted] **. The plant relies on Powder River Basin (PRB) coal, which increased significantly in the past year.[28] From 2021 to 2022, the fuel costs per MWh generated at Sioux increased by 27 percent.[29] ** [redacted] **

Figure 3: Changes in Coal Price Forecasts ($ per ton)[30] (CONFIDENTIAL)

** [redacted] **

[28] *See also* EIA, Coal Markets Archive, *available at* https://www.eia.gov/coal/markets/#tabs-prices-1.

[29] Comings Workpaper – Company Response to Sierra Club Data Request 1-1, SIERRA_1-SC_001_1-Att-SC 001.1-e-j-k-l-n-o-s.

[30] Comings Workpaper CONFIDENTIAL – Company Response to Sierra Club Data Request 1-9, SIERRA_1-SC_001_9-Att-Commodity_Price_Report for April 30, 2021 and August 31, 2022.

Q. Do the units cycle often because of their high costs?

A. Yes. ** [redacted][31] [redacted] **

Q. What do you recommend regarding the future of Sioux units 1 and 2?

A. The continued unreliability of these units, their high fuel costs, and the more competitive replacement costs (especially given the recent passage of the IRA) mean they should be considered for retirement soon. The Company expects these units to be even more unreliable in the next five years, which will reduce their capacity value. Despite this, Ameren extended the retirement date of the units from 2028 to 2030. As I describe in the next section, the units could also require expensive emission controls by 2027. The Company should at least consider this date for retirement of the Sioux units given the economic and regulatory pressure on the units.

[31] Sierra Club Data Request 1-4, SIERRA_1-SC_001_4-Att-SC 001.4 CONF

C. <u>The Sioux and Labadie Units Could Require Costly Controls to Comply with Ozone Regulations.</u>

Q. Are the Sioux and Labadie units at-risk of needing substantial emission controls to comply with ambient air quality standards?

A. Yes. The Sioux and Labadie units all emit high levels of nitrogen oxide (NOx) which is a precursor to ozone (also known as smog), as well as sulfur dioxide (SO2), which contributes to poor air quality in the areas surrounding Ameren's coal units as well as protected national parks and wilderness areas.[32] There are several on-going environmental regulations that could lead some or all of these units to need to install selective catalytic reduction (SCR) or flue gas desulfurization (FGD or scrubber) technology, including Regional Haze and ozone transport rules (which are tied to the ambient ozone emissions standards). Currently, the Sioux units have selective non-catalytic reduction (SNCR) which achieves much less emission reduction that an SCR; and the Labadie units have neither SCNR nor SCR nor FGD.

In this section, I focus on the Good Neighbor Plan and the Regional Haze Rule, which are the most pressing regulations that could lead to an SCR at either plant or FGD requirements at Labadie or potential upgrades to the existing FGD at Sioux. Despite the lack of SCR controls at both Labadie and Sioux, and the increasing stringency of ozone and haze regulations, Ameren has continually turned a blind eye by avoiding a rigorous

[32] *United States v. Ameren Missouri*, 421 F. Supp. 3d 729 (E.D. Mo. 2019), *aff'd in part*, 9 F.4th 989 (8th Cir. 2021) (noting health impacts from coal-burning power plants, including Labadie and Rush Island); *see also Missouri Dep't Nat. Res.*, Missouri State Implementation Plan Revision—Missouri Regional Haze Plan for the Second Planning Period at 61-64 (Aug. 25, 2022) (describing visibility pollution impacts of Ameren's fleet at Class I areas), *available at* https://dnr.mo.gov/document-search/state-implementation-plan-revision-missouri-regional-haze-plan-second-planning-period.

assessment of its units' futures with these in mind. Regarding the Good Neighbor Plan, the Company stated that it "will be evaluating compliance options once a final rule is published" but, as I describe below, it could be consequential for the near-term life of these coal units.[33]

Q. Please describe the EPA's Good Neighbor Plan.

A. In February 2022, the U.S. EPA proposed the Good Neighbor Plan, the latest iteration of ozone air transport rules that address how upwind polluters contribute to downwind ozone levels. Previous versions of clean transport rules included the Cross-State Air Pollution Rule (CSAPR) and the Clean Air Interstate Rule (CAIR). The new rule would lead many coal units that are currently lacking in the most effective nitrogen oxide control, selective catalytic reduction (SCR), to either install those controls, purchase costly allowances, or retire.

The Good Neighbor Plan and its predecessors require reductions in nitrogen oxide emissions to reduce the formation of ground-level ozone. Per the Clean Air Act (CAA), the EPA must set National Ambient Air Quality Standards (NAAQS) for certain pollutants, such as ground-level ozone, which have adverse impacts on human health. The CAA includes a "good neighbor" provision which requires the EPA to regulate upwind sources that significantly contribute to, or interfere, with downwind states' noncompliance with the NAAQS.[34] The states (or EPA when the states fail to act) have a statutory obligation to update their good neighbor regulations, and reduce pollution from

[33] Ameren Missouri 2022 Change in Preferred Plan, p.22.

[34] *See* U.S. EPA, *Interstate Air Pollution Transport*, (March 17, 2022), *available at* https://www.epa.gov/interstate-air-pollution-transport/interstate-air-pollution-transport.

upwind sources that contribute to poor downwind air quality, whenever EPA updates the NAAQS. In 2015, EPA tightened the ozone NAAQS to 70 parts per billion (ppb) to address public health concerns. Accordingly, the states had an obligation to update their pollution control requirements for upwind sources that contribute to downwind nonattainment, like Labadie and Sioux. Because Missouri and several other states failed to timely submit lawful good neighbor plans of their own, EPA must finalize a plan for those states by April 2023.

In April 2022, EPA proposed a Good Neighbor Plan that requires that 25 upwind states, including Missouri, reduce their nitrogen oxide emissions at power plants to avoid affecting other states' abilities to meet their 2015 ozone NAAQS levels.[35] The EPA has issued a proposed Federal Implementation Plan (FIP) for the 25 states which requires them to participate in an allowance trading program for ozone season (May through September) starting in 2023; and imposes a daily emission limit starting in 2027. At that time, the EPA states that the limits will effectively force SCR installation on coal units larger than 100 MW otherwise those units need to "find other means of compliance, or retire."[36]

[35] *See* U.S. EPA, *Good Neighbor Plan for 2015 Ozone NAAQS*, (August 26, 2022), *available at* https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs. California is only required to reduce industrial emissions while Tennessee, Alabama and Delaware are only required to reduce power plant emissions. Twenty-two other states, such as Missouri, are required to reduce both power plant and industrial emissions.

[36] U.S. EPA, *Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*. p. ES-7,8, *available at* https://www.epa.gov/system/files/documents/2022-03/ria-for-proposed-fip-addressing-regional-ozone-transport-for-the-2015-ozone-naaqs.pdf.

Q. If finalized, would the Good Neighbor Plan have a material effect on the U.S. coal fleet and Ameren's in particular?

A. Yes. The EPA estimated that the proposed Good Neighbor Plan would lead to 18 GW of additional coal retirements by 2030.[37] The State of Missouri's generators emitted 20,388 tons of NOx in ozone season in 2021.[38] About 29 percent of these emissions came from the Labadie and Sioux units.[39] The Good Neighbor Plan would decrease the allowed NOx emissions in ozone season in Missouri by 39 percent from 2023 to 2026-2027.[40] These allocations already account for the fact that Meremec and Rush Island coal units will both be retired by 2026. In Figure 1 below are the EPA's "illustrative" allocations of allowed ozone season NOx emissions for the Sioux and Labadie units, along with their actual 2021 emissions. The Good Neighbor Plan allocations would lead to between 73 and 76 percent reduction of NOx at the Sioux units and between 34 and 42 percent reduction at the Labadie units.

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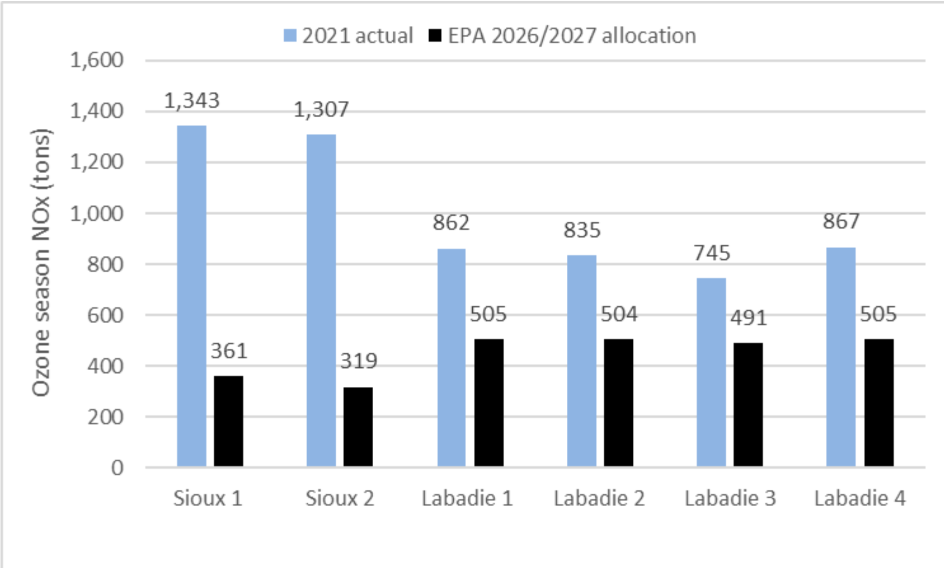
[37] *Id*., p. 4-18

[38] U.S EPA, *Good Neighbor Plan for 2015 Ozone NAAQS*. Technical Support Documents, *Unit-level Allocations and Underlying Data for the Proposed Rule* (xlsx), "Underlying Data for FIP" tab, (last accessed January 1, 2023), *available at* https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs.

[39] *Id*.

[40] *Id*. The 2026 budget represents compliance with the daily emission rate requirements in 2027 because the EPA assumes that most units that would install NOx controls would do so by 2026. *See* U.S. EPA, *Regulatory Impact Analysis for Proposed Federal Implementation Plan Addressing Regional Ozone Transport for the 2015 Ozone National Ambient Air Quality Standard*, p. ES-8 footnote.

Figure 4: Sioux and Labadie Ozone Season NOx Emissions[41]



Q. Are the Sioux and Labadie units likely to need SCR if the Good Neighbor Plan is finalized?

A. Yes. None of the Sioux or Labadie units have SCR controls which would likely be needed to meet NOx emission targets if the Good Neighbor Plan were finalized. The only other options for compliance would be to purchase NOx allowances or retire the units. The allowance prices are likely to be quite high as the 25 states attempt to comply with the rule; recently they reached $48,000 per ton.[42] If for instance, the allowance prices were $20,000 per ton (less than half the recent peak in prices) then the compliance costs would be nearly $40 million a year for the Sioux plant and over $26 million a year for

[41] U.S EPA. *Good Neighbor Plan for 2015 Ozone NAAQS*. Technical Support Documents, *Unit-level Allocations and Underlying Data for the Proposed Rule* (xlsx), "Underlying Data for FIP" tab, (last accessed January 1, 2023), *available at* https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs.

[42] Michael Ball, *Viewpoint: NOx could rise on new regulations*, Argus Media, (December 29, 2022), *available at* https://www.argusmedia.com/en/news/2405066-viewpoint-nox-could-rise-on-new-regulations?backToResults=true.

Labadie.[43] Given the high costs of allowances, the final Good Neighbor Plan is likely to lead to an SCR versus retirement decision for these units.

Q. What is an estimate of the costs of SCRs at the Sioux and Labadie units?

A. Using assumptions from the U.S. Energy Information Administration (EIA), the capital costs of SCRs would be approximately $132 million per unit at Sioux (or $264 million for the plant) and $153 million per unit at Labadie ($612 million for the plant).[44] Ameren has stated that costs of SCR at each Labadie unit would be between $100 and $250 million (between $400 million and $1 billion for the plant); and says that SCR option for Sioux are "under consideration" but no cost estimates are available.[45] (Note that these capital costs do not include the rate of return on the SCR investments that Ameren would receive if the costs are allowed in rate base, nor do they include annual operating costs.)

Q. Should Ameren install SCRs on all units that require them?

A. No. As an initial matter, I note that Ameren's approach to environmental compliance has been to only evaluate the impact of regulations on their coal units' retirement dates once the rules are finalized, but this wait and see approach is not effective long-term planning. A long-term resource decision needs to account for regulatory risks, to the best of the planner's abilities and given the knowledge available at the time of that decision. The

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[44] EIA, *Assumptions to the Annual Energy Outlook 2022: Electricity Market Module,* Table 8, p. 23, *available at* https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

[45] Exhibit TC-2, Company Response to Sierra Club Data Request 3-1(b)(i).

Good Neighbor Plan was proposed nearly a year ago; and as I understand it, EPA must take final action implementing a federal plan by April 30, 2023.[46]

If faced with a requirement to install these costly SCRs at any of these units, Ameren will have to consider the units' retirement and replacement as an alternative. But the Company has not conducted an evaluation that looks at the question of SCR versus earlier retirement of these units due to the Good Neighbor Plan.[47] This represents a failure to take a hard look at these units' viability given known risks.

Q. Is the Good Neighbor Plan the only rule that could require major emission controls in the future?

A. No. The risk of tightening emissions and increased environmental compliance costs has been on-going and will not cease. Another Clean Air Act regulation likely to come into play in the next two years is the Regional Haze Rule, which requires large sources of visibility-impairing pollution, like Ameren's Labadie and Sioux power plants, to reduce NOx and SO_2 emissions to ensure "reasonable progress" towards natural visibility in national parks and wilderness areas by 2064.[48] Given the magnitude of sulfur dioxide and nitrogen oxide emissions from Labadie and Sioux, each of the EGUs at those power plants could be subject to additional controls. Ameren's own analysis indicates that FGD technology at the Labadie units could cost between $409 and $446 million per unit.[49]

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[46] 87 Fed. Reg. 20,036, 20,057 (April 6, 2022).

[47] Exhibit TC-2, Company Response to Sierra Club Data Request 3-1(c).

[48] 42 U.S.C. § 7491(b)(2); *See generally* 40 C.F.R. § 51.308(d).

[49] Exhibit TC-4, Ameren, Response to Missouri Department of Natural Resources, Regional Haze Four-Factor Analysis—Information Collection Request Dated July 29, 2020 For the

Although the Sioux units have FGD technology, the plant still emits between 0.08 and 0.106 lbs of SO_2 per MMbtu[50] which could likely be improved.[51] Notably, in August 2022, EPA issued a final decision finding that Missouri failed to submit a Regional Haze plan, as required under the Clean Air Act.[52] Consequently, EPA must, anytime within two years, either implement a federal plan in Missouri's place or approve a lawful state plan.[53] If EPA determines that additional controls are cost-effective and will improve visibility in affected national parks and wilderness areas, compliance is typically required within five years.[54] With that timeline in mind, and given the magnitude of emissions from Ameren's aging coal fleet and the cost-effective pollution reduction technologies typically installed at similarly-situated sources,[55] it is unreasonable for Ameren to refuse to evaluate (let alone acknowledge) the potential retirement associated with compliance with the Regional Haze Rule.

Labadie Energy Center, at pdf page 105, *available at* https://dnr.mo.gov/document/missouri-regional-haze-plan-second-planning-period-appendix-c-1-c-7.

[50] EPA, Coal-fired Characteristics and Controls: 2021, *available at* https://www.epa.gov/airmarkets/facility-level-comparisons.

[51] *Missouri Dep't Nat. Res.*, Missouri State Implementation Plan Revision—Missouri Regional Haze Plan for the Second Planning Period, App'x G-2 at pdf page 54 (Aug. 25, 2022) (National Parks Service noting achievable emission rate of 0.02 to 0.04 lb/mmbtu with FGD technology) describing visibility pollution impacts of Ameren's fleet at Class I areas), *available at* https://dnr.mo.gov/document/missouri-regional-haze-plan-second-planning-period-appendix-g-2.

[52] 87 Fed. Reg. 52,856 (August 30, 2022).

[53] *Id.*; *See also* 42 U.S.C. § 7410(c)(1).

[54] 42 U.S.C. § 7491(g)(4).

[55] EPA and other states have consistently recognized that FGD or DSI control technologies are cost effective and commonly used in the industry, especially for units like Rush Island and Labadie, all of which were constructed in the 1970s. *See, e.g.*, 40 C.F.R. pt. 51, App. Y § (IV)(E)(4) (EPA's presumptive best available retrofit technology requires a 95% reduction in sulfur dioxide emissions, typically achieved by the installation of FGD technology).

In any case, it is also unlikely that the Good Neighbor Plan or Regional Haze Rule will to be the last word from EPA on emission reductions from Ameren's coal fleet. First, the basis of EPA's Good Neighbor Plan rule is the 2015 ozone NAAQS limit of 70 ppb (parts per billion). But the ozone NAAQS limit has decreased multiple times: it was 80 ppb in 1997, 75 ppb in 2008, then 70 ppb in 2015; and EPA must reconsider that standard in 2025 and decrease it if warranted. If it does, then a new transport rule will replace the Good Neighbor Plan, as it replaced CSAPR which replaced the CAIR, and so forth. Second, on January 5, 2023, EPA proposed to lower the primary annual NAAQS for fine particulate matter ($PM_{2.5}$) standard by lowering the level from 12.0 µg/m3 to within the range of 9.0 to 10.0 µg/m^3, which could require large sources of particulate matter like Labadie and Sioux to reduce emissions.[56] Specifically, based on current monitoring data, areas like St. Louis, Missouri, and Madison County, Illinois could be designated as failing to comply with the proposed standard,[57] which would likely require Ameren to make decisions about whether to invest in additional pollution control measures by 2028, depending on the implementation and timing of the final rule.[58] Finally, EPA is also

[56] *See* EPA, Reconsideration of the National Ambient Air Quality Standards for Particulate Matter, *available at* https://www.epa.gov/system/files/documents/2023-01/PM%20NAAQS%20NPRM%20-%20prepublication%20version%20for%20web.pdf.

[57] *See* EPA, Fine Particle Concentrations for Counties with Monitors Based on Air Quality Data from 2019 – 2021, *available at* https://www.epa.gov/system/files/documents/2023-01/Fine%20Particle%20Concentrations%20for%20Counties%20with%20Monitors.pdf.

[58] In the proposal, EPA stated its expectation to finalize an updated PM2.5 standard by the end of 2023, *id*. at 419. which would then require the agency to designate areas of the country as being in nonattainment by the end of 2025. States would be required within three years (and possibly sooner) to develop and implement plans, including "reasonably available control technology" at major sources of PM2.5 pollution, like Labadie and Sioux, to ensure attainment of the standard as expeditiously as practicable. *See* 42 U.S.C. §§ 7407(d); 7502(b).

scheduled this year to revisit the national standard for nitrogen dioxide, which, like the standard for ozone could require large sources of nitrogen oxides to install expensive SCR technology.

III. <u>In Future Rate Cases, Avoidable Spending at the Coal Units Should Be Disallowed.</u>

Q. Should Ameren's capital investment decisions consider the potential for earlier retirement of the Sioux units?

A. In the next five years, the Company plans to spend over ** [redacted] **.[59] But if any of these units were to retire earlier than currently planned, then there is potential to avoid some of these investments and therefore avoid associated rate increases. Otherwise, capital spending could be incurred—even if a unit may be retired earlier than planned at the time—and by the time a rate case occurs it is more likely that these costs will be incurred and included in rates. The Company should also do this for plants that it is already planning to retire soon, such as Rush Island, to see if there are benefits from stopping previously planned spending.

Q. How would the Commission determine what capital costs were avoidable?

A. The Commission should compel the Company to identify any "avoidable" spending with select retirement dates, for instance 2027 when considering compliance with the Good Neighbor Plan. The assessment of avoidable versus unavoidable costs should consider whether major emission controls that may be needed for existing or pending regulations, looking at the potential that the unit(s) would to be retired earlier than currently planned.

[59] Comings Workpaper CONFIDENTIAL - Company Response to Sierra Club Data Request 1-11, SIERRA_1-SC_001_11-Att-SC 001.11 Coal CapEx.

In this manner, if future costs are avoidable then the Company would flag that spending ahead of time; and other parties could review these designations and consider whether any additional costs should be considered avoidable for future reference. The Commission could then earmark avoidable costs for future allowance or disallowance in upcoming rate cases.

Q. Does avoidable spending only happen when there is a definitive retirement decision?

A. No. The possibility of earlier retirement should compel Ameren to consider whether some capital spending could be avoided and the Commission could disallow those costs unless the Company shows that early retirement is not advantageous. The Sioux units are likely to be evaluated for retirement in the upcoming IRP and, as I have discussed, the Good Neighbor Plan alone should lead to a retirement or retrofit assessment for Sioux and Labadie units. If avoidable costs are incurred, but the Company subsequently decides to retire the units earlier than currently planned, then ratepayers will not realize savings from avoiding those costs because they were included in rates—and these costs will become stranded.

Q. Has this framework been used in other utility cases?

A. Yes. Before the Michigan Public Service Commission, the 2018 Consumers Energy IRP case settlement required Consumers Energy to identify "avoidable capital expenditures (environmental and non-environmental) and avoidable major maintenance for Campbell units 1 and 2 in 2024 and 2025 retirement scenarios."[60] Subsequent Michigan Commission

[60] Michigan Public Service Commission (MI PSC), Case No. U-20165, June 7, 2019, Order approving Settlement Agreement, par. 6.

rulings for Consumers Energy and DTE Energy resulted in disallowances of "avoidable" costs identified by that utility and by other parties due to possibility of earlier retirement.[61] This framework could be applied in Missouri so that ratepayers would save on unnecessary capital spending.

Q. Once a cost is labeled avoidable, is it still possible to allow it in rates in the future?

A. Yes, but these costs should only be recovered in rates if a reasonable evaluation has shown that unit(s) should not retire early. In the meantime, these costs could be deferred until such a determination is made and then either allowed or disallowed based on the outcome. The important change in framing here is that the default should not be that the unit(s) operate as long as the Company currently expects, especially when longer operation is unrealistic given the myriad reasons I have discussed above.

IV. <u>Conclusion and Recommendations</u>

Q. What do you recommend to the Commission?

A. For the reasons explained above I recommend the following:

1. The Commission compel Ameren to evaluate the costs of compliance the Good Neighbor Plan and Regional Haze including the option to retire and replace coal units rather than invest in new SCR controls in its next IRP.
2. The Commission compel Ameren to identify future capital spending that could be avoided with earlier retirement of the Sioux and Labadie units, at least considering

[61] MI PSC, Case No. U-20836 and Case No. U-20963.

2027 as a retirement year but possibly other dates that coincide with existing or pending compliance and/or low-cost replacement options.

Q. Does this conclude your testimony?

A. Yes.

CERTIFICATE OF SERVICE

I, Joshua Smith, certify that a copy of the foregoing Sierra Club submission was served upon all parties of record in this proceeding on January 10, 2023, by electronic mail, as permitted by the presiding officer.

Joshua Smith

Sierra Club Environmental Law Program

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PROFESSIONAL EXPERIENCE

Applied Economics Clinic, Arlington, MA. Senior Researcher, June 2017 – Present.

Provides technical expertise on electric utility regulation, energy markets, and energy policy. Clients are primarily public service organizations working on topics related to the environment, consumer rights, the energy sector, and community equity.

Synapse Energy Economics Inc., Cambridge, MA. Senior Associate, July 2014 – June 2017, Associate, July 2011 – July 2014.

Provided expert testimony and reports on energy system planning, coal plant economics and economic impacts. Performed benefit-cost analyses and research on energy and environmental issues.

Ideas42, Boston, MA. Senior Associate, 2010 – 2011.

Organized studies analyzing behavior of consumers regarding finances, working with top researchers in behavioral economics. Managed studies of mortgage default mitigation and case studies of financial innovations in developing countries.

Economic Development Research Group Inc., Boston, MA. Research Analyst, Economic Consultant, 2005 – 2010.

Performed economic impact modeling and benefit-cost analyses using IMPLAN and REMI for transportation and renewable energy projects, including support for Federal stimulus applications. Developed a unique web-tool for the National Academy of Sciences on linkages between economic development and transportation.

Harmon Law Offices, LLC., Newton, MA. Billing Coordinator, Accounting Liaison, 2002 – 2005.

Allocated IOLTA and Escrow funds, performed bank reconciliation and accounts receivable. Projected legal fees and costs.

Massachusetts Department of Public Health, Boston, MA. Data Analyst (contract), 2002.

Designed statistical programs using SAS based on data from health-related surveys. Extrapolated trends in health awareness and developed benchmarks for performance of clinics for a statewide assessment.

EDUCATION

Tufts University, Medford, MA

Master of Arts in Economics, 2007

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AFFILIATIONS

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Resume dated November 2022

Exhibit TC-2

Public Company Responses

to Sierra Club Data Requests

Data Requests

Ameren Response to Sierra Club Request 3-1

Ameren Response to Sierra Club Request 5

Ameren Missouri
Case Name: ER-2022-0337
Docket No(s): 2022 Electric Rate Review

Response to Discovery Request: SIERRA 3-SC 003.1
Date of Response: 1/3/2023
Witness: N/A

Question:Refer to SIERRA_1-SC_001_12-Att-SC 001.12 Attach RR Model_Capex-OM updated 12-8-2021 and SIERRA 1-SC 001. a) Has the Company identified capital spending that could be avoided at any of its coal units if they retired earlier than currently planned-such as the dates evaluated in the 2020 IRP and the plan update? i) If so, please identify the coal unit, potential retirement date, and the corresponding capital spending that would be avoided in that event.
ii) If not, please explain why not.

b) Since the 2020 IRP was conducted, has the Company evaluated the potential need for nitrogen oxide controls for any of the Labadie or Sioux units-such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR)? i) If so, please identify the coal unit, the type of emission control, and the estimated costs of these controls, and produce any document(s) reflecting such evaluation.
ii) If so, please explain the Company's stance on the likelihood of these controls being required at these units, including any supporting documentation and analyses.
iii) If not, please explain why not.

c) Since the 2020 IRP was conducted, has the Company evaluated the potential for retiring any of the Labadie or Sioux coal units earlier than currently planned if they were to require nitrogen oxide controls? i) If so, please identify the coal unit, the type of emission control, the estimated costs of these controls, the retirement date considered and the corresponding regulation, and produce any document(s) reflecting such evaluation.
ii) If not, please explain why not.

d) Has the Company considered the potential impact of the EPA's Good Neighbor Rule on any of the Labadie or Sioux units? i) If so, please identify the coal unit, the type of emission control, the estimated costs of these controls, and earlier retirement date considered (if any), and produce any document(s) reflecting such consideration.
ii) If not, please explain why not.

Response:

Prepared By: Hande Berk (1.a)/Don Clayton 1.b-d)
Title: Manager, Electric Resource Planning / Supervising Engineer, Performance & Reliability
Date:

1. a) The Company most recently forecasted different levels of capital spending corresponding to different retirement dates for Labadie and Sioux in the 2020 IRP filing. Project-by-project detail can be found in the attached files "SC 003.1a Sioux.xlsx", "SC 003.1a Labadie.xlsx".

With respect to Sioux, to account for the change in Sioux's planned retirement date from 2028 to 2030, as outlined in the June 2022 Notice of Change in Preferred Plan, the Company assumed a total of approximately $6.7 million of additional capital expenditures at Sioux over the 2028 to 2030 timeframe. There is no project-by-project detail for these additional expenditures.

b) Yes

i) Both SCR and SnCR are currently being evaluated for Labadie Units 1-4. The estimated capital cost for SCR on each Labadie unit is $100 to $250 million per the attached estimates provided by Black & Veatch and Sargent & Lundy. The estimated capital equipment cost for SnCR on each Labadie unit is $3.5 million per the attached estimate from FuelTech. We do not have an estimate for labor and owner's costs. All of these estimates are preliminary since the evaluation is not complete. Sioux Units 1&2 have existing SnCR controls and these controls will be returned to service during future ozone season operation. A capital project is underway to restore the Rich Reagent Injection (RRI) NOx control injection ports on the Sioux Unit 1&2 boilers. The full estimated cost to restore the RRI system has not been developed. A current cost estimate for installing SCR on the Sioux units is not available. Various SCR options for Sioux are still under consideration.

ii) The evaluation of NOx control options is not complete and the exact likelihood of the implementation of various options is not known at this time. The workbook titled CSAPR_Projection_Spreadsheet-PerfEng-Nov22-DR was developed to analyze the proposed CSAPR update and can be used to assess various compliance options.

iii) n/a

c) No

i. n/a

ii. The evaluation of NOx control options is not complete and cost estimates are preliminary.

d) Yes

iii. See response to 3.1b and 3.1c above.

iv. n/a

Ameren Missouri
Case Name: EO-2022-0362
Docket No(s): Change in IRP Preferred Plan

Response to Discovery Request: SIERRA-SC 005
Date of Response: 8/18/2022
Witness: N/A

Question:Please provide all analyses, data, and documents supporting Ameren's decision to delay retirement of Sioux Energy Center by two years from 2028 to 2030.

Response:

Prepared By: Matt Michels
Title: Director – Corporate Analysis
Date: August 12, 2022

The decision to change the retirement date for the Sioux Energy Center was made in conjunction with the Company's notification of change in preferred plan. A summary of the economic analysis of three different Sioux retirement date options is presented in the filed report on page 27 and supported by the detailed analysis included in the associated work papers, which Staff has. Ameren Missouri also considered the time required to place new natural gas combined cycle resources into commercial operation and the need to ensure reliability until completion. A schedule for implementation of new natural gas combined cycle generators is shown in Attachment SC 005-1.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's 2022 Change in Preferred Plan Integrated Resource Plan	)))	File No. EO-2022-0362

SIERRA CLUB'S COMMENTS ON AMEREN MISSOURI'S 2022 CHANGE IN PREFERRED PLAN INTEGRATED RESOURCE PLAN

Sierra Club respectfully submits these comments on the 2022 Change in Preferred Plan, Integrated Resource Plan filed by Union Electric Company ("Ameren" or the "Company"). Sierra Club respectfully requests that the Company agree to prepare a revised IRP filing that corrects the deficiencies identified herein. As explained more thoroughly below, Sierra Club offers the following findings on Ameren's 2022 Change in Preferred Plan Integrated Resource Plan ("IRP Change"):

(1) Ameren should update its modeling to reflect the expanded tax credits provided in the Inflation Reduction Act ("IRA"). The IRA reflects a significant change in federal energy law that, if modeled, would be expected to change Ameren's plan by increasing deployment of solar, wind, and batteries. The Company's CEO has noted that the new law would lower the costs of the clean energy transition for Ameren and its customers.[1] Ameren's customers deserve a prompt response to this significant change in federal energy incentives.

[1] Ameren Q2 2022 Earnings Call, p.11, August 5, 2022. Available at: https://s21.q4cdn.com/448935352/files/doc_financials/2022/q2/Ameren-Corporation-Q2-2022-Earnings-Call-Transcript.pdf

(2) Ameren failed to sufficiently address the future of its coal units. The Company only modeled the retirement of the Sioux plant for three possible years (2028, 2030, and 2033) and did not model a plan with early retirement of Labadie units. This approach ignores the possibility of lower-cost resource portfolios that retire those units sooner. The Company also has substantial headroom in terms of capacity.

(3) Ameren is locking in the decision to build a large combined cycle gas plant. The Company tries to justify hard-coding this major investment into the resource plan by claiming that the plant will eventually use hydrogen and carbon capture storage; but it did not estimate the costs required to adopt and use these technologies. Ameren also tried to justify the gas plant on reliability terms; but the reliability analysis was incomplete and lacked documentation.

(4) Ameren should consider battery storage as a viable replacement resource in the near and medium-term. The Company adds battery storage in its plan starting in 2035; but it also failed to model longer-duration batteries and solar-battery hybrids, both which will likely qualify for higher tax credits due to recent legislation.

(5) Ameren has arbitrarily included a premium for solar PV and wind costs that disfavors these resources in its modeling. This premium is not justified given more recent forecasts (using the same source as Ameren) and recent legislation that will decrease the costs of these resources even further.

(6) Ameren is only modeling self-build resources. This unfairly misses the opportunity for cost savings inherent to other ownership, such as power purchase agreements ("PPAs").

(7) Ameren continues to overstate the job impacts of new gas generation and understate those from new solar PV. The Company needs to document and update its job impact estimates.

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I. Deficiency 1: Ameren should update its modeling to reflect current federal law on energy tax credits.

In its 2022 IRP Change, Ameren mentioned the potential for "extension and expansion of tax credits" as a factor that could influence "plan performance and planning decisions."[2] The Company's consultant, Roland Berger, also estimated the impact of a scenario of legislation extending tax credits for renewable resources. Recently, Congress passed and President Biden signed into law the Inflation Reduction Act which dramatically alters and expands federal tax credits available for zero greenhouse gas emitting facilities such as solar, wind, and batteries. Ameren should revise its modeling for this IRP Change to include the expanded tax credits. Under the IRA, all zero emitting resources will be permitted to take a 30% Investment Tax Credit ("ITC") or a Production Tax Credit ("PTC") valued at $25/MWh if the generator pays prevailing wages.[3] Such projects are eligible for a 10% adder if the project is located in an "energy community," generally defined as one with a history of fossil fuel generation, extraction, transport, or processing, a brownfield, or where a coal unit has retired.[4] (Ameren could, for example, install batteries at its Meramec or Rush Island sites and federal taxpayer will cover 40% of the cost.) Zero emitting resources are also eligible for an additional 10% increase to the

[2] Ameren Missouri 2022 Change in Preferred Plan IRP, p. 11.

[3] *See* Inflation Reduction Act Sections 13101 (expanded and extended Production Tax Credit); 13102 (expanded and extended Investment Tax Credit); 13701 (new Clean Electricity Production Credit); 13702 (new Clean Electricity Investment Credit). *See also* Congressional Research Service, Tax Provisions in the Inflation Reduction Act of 2022 (H.R. 5376), dated August 10, 2022, available online at: https://crsreports.congress.gov/product/pdf/R/R47202.

[4] *Id*.

credit if U.S. manufactured components are used.[5] The expanded credits extend through at least December 31, 2032.[6]

Ameren should update its modeling to incorporate the Inflation Reduction Act changes for two general reasons. First, the expansion of the clean credits available is dramatic. For example, a lower PTC for wind was going to expire for projects that started construction after 2021; now, wind is eligible for the full PTC through at least 2032. Ameren only included battery storage in its preferred plan starting in 2035, but standalone batteries are now eligible for a 30% ITC through at least 2032 (40% if located at the site of a coal unit that has retired since 2009)—which is a major shift from previous policy. Solar credits have increased back to the highest previous level of 30% for the ITC extended through 2032, rather than sunsetting in the short-term. Solar projects may also qualify to receive this credit using the PTC mechanism, so that utilities will be able to capture the benefits sooner than before.[7] The difference between federal law and Ameren's modeling is now vast. The CEO of Ameren discussed the cost impacts of this new legislation:

> "[T]he PTC for solar is a positive versus the prior ITC and transferability provisions, which are things that we really think could help us to pass the value associated with some of these tax credits to our customers more swiftly. Like I said, net, we think that the legislation overall is good and will help facilitate a lower cost transition to this clean energy."[8]

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[5] *Id*.

[6] *Id*.

[7] *Id*.; *see also* Ethan Howland, "Senate passes Inflation Reduction Act with $369B in energy and climate spending," Utility Dive (August 8, 2022), available at https://www.utilitydive.com/news/senate-inflation-reduction-act-climate-solar-tax/629087/.

[8] Ameren Q2 2022 Earnings Call, p.11, (August 5, 2022), available at: https://s21.q4cdn.com/448935352/files/doc_financials/2022/q2/Ameren-Corporation-Q2-2022-Earnings-Call-Transcript.pdf.

The Company has contemplated the potential for tax credit extensions but its analysis is insufficient for two main reasons: 1) the scenario with tax credit extensions is far less aggressive than the provisions of the IRA; and 2) the Company did not re-evaluate coal retirements under this more favorable tax credit regime. The Roland Berger analysis included by Ameren looked at a scenario where tax credits were extended and calculated the savings of the Company's preferred plan versus another plan with the same coal unit retirement dates (also known as the "Renewable Transition" and "Renewables for Capacity Need" plans, respectively).[9] But importantly that scenario did not include many key aspects of the IRA, including: 1) extension of the PTC through 2032; 2) the use of the ITC for standalone batteries; 3) the allowance for the PTC for solar PV resources (alluded to by the CEO above); and 4) the possibility of higher credits dependent on the amount of domestic manufacturing employed and/or the project's location.[10] Moreover, a change in the costs of clean resources should also lead to a re-evaluation of the economics of existing resources as well. We agree with Ameren that the IRA would reduce the cost of its current plan; but now that the IRA is on the books, the question is: what is the best plan given this new tax credit regime? With that in mind, Ameren should update its modeling as soon as possible because, as explained herein, its modeling already shows a benefit to early retirement of coal and replacement with clean energy resources.

II. Deficiency 2: Ameren did a minimal assessment of coal retirements.

Ameren's 2022 IRP filing includes major resource decisions that were pre-determined, namely the retirement of the Sioux plant and replacing it with a large gas plant. The Commission

[9] Ameren Missouri 2022 Change in Preferred Plan IRP, p. 21.

[10] Ameren Missouri 2022 Change in Preferred Plan IRP, Appendix A, p.18-19.

has previously ordered Ameren to compare the continued operation of its coal units—accounting for all future costs—to their replacement.[11] But the Company's modeling has failed to rigorously examine the economic retirement of existing units in two key ways: 1) the modeling limited retirement options for Sioux Energy Center to only 2028, 2030, and 2033, and; 2) failing to test the economics of retiring other coal units early, such as Labadie.

The Company should incrementally test a series of retirement years moving forward from 2025, rather than only testing a few selected, fixed dates for retirement. If only conducting the latter, it would be unclear whether the year chosen was optimal for electric customers because the decision set was too limited. Of course, failing to model any early retirement for other units leaves this question of optimal time completely unanswered.

Ameren's alternative resource plans ("ARPs") only looked at limited retirement dates (2028, 2030, and 2033) for Sioux. Retiring the plant in these three years results in miniscule differences in the present value revenue requirement ("PVRR") among the ARPs. For instance, retiring the plant in 2028 only costs 0.03 percent more than retiring it in 2030.[12] The Company stated that the 2030 retirement was supported by the timing of the natural gas-fired combined cycle ("NGCC") plant addition in 2031.[13] This is poor planning practice because the coal plant should be retired when economically optimal (while evaluating <u>all</u> viable resource options) rather than determined by the availability of a pre-selected resource.

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[11] Revised Order Establishing Special Contemporary Resource Planning Issues, File No. EO-2020-0047, at Issue O (issued Dec. 3, 2019), ("Analyze and document on a unit-by-unit basis the net present value revenue requirement of the relative economics of continuing to operate each Ameren Missouri coal-fired generating unit versus retiring and replacing each such unit in light of all the environmental, capital, fuel, and O&M expenses needed to keep each such unit operating as compared to the cost of other demand-side and supply-side resources.").

[12] Ameren Missouri 2022 Change in Preferred Plan IRP, p. 31, Table 9.

[13] Ameren Missouri 2022 Change in Preferred Plan IRP, p. 30.

The Company should have also tested resource plans with early retirement of Labadie, which is not scheduled to retire until 2036 (two units) and 2042 (two units). In 2020, Labadie emitted more carbon dioxide (“CO_2”) than any other power plant in the U.S (17.9 million tons); had the second highest sulfur dioxide (“SO_2”) emissions of any plant in the country (39,392 tons); and the eleventh highest nitrogen oxide emissions (“NOx”) of any plant in the nation (7,649 tons).[14] Given that Labadie is one of the largest sources of air pollution in the country, the potential for retiring it earlier should have been explored in Ameren’s resource plans.

By refusing to consider alternative retirement dates for Labadie, Ameren deprives the Commission and ratepayers of the opportunity to meaningfully evaluate potentially lesser-cost resource options for serving the Company’s needs. The plant is vulnerable to high regulatory compliance costs for at least two reasons. First, under EPA’s recently-proposed Good Neighbor Rule, which is designed to protect against harmful ground-level smog pollution, each of the Labadie units would likely be required to install selective catalytic reduction pollution controls by 2026, or procure pollution credits commensurate with the pollution reductions achievable with those controls.[15] Second, under EPA’s Regional Haze Rule—which required Missouri to implement regulations in 2021 and revise regulations in 2028 to reduce sulfur dioxide and nitrogen oxide pollution that impair visibility in national parks—the Labadie units could similarly be required to install expensive pollution controls.[16] Thus, planning to operate the plant for the better part of two more decades carries substantial risk to ratepayers.

[14] Energy Information Administration, “Emissions by Plant and Region for 2020,” available at https://www.eia.gov/electricity/data/emissions/

[15] 87 Fed. Reg. 20,036 (Apr. 6, 2022).

[16] *See* 42 U.S.C. § 7491(b)(2); 40 C.F.R. § 51.308.

Ameren's failure to robustly study more retirement options at its existing coal units is a deficiency under the Missouri IRP rule. As noted in Section III, Missouri IRP rule 20 CSR 4240-22.010(C) requires that Ameren consider the "[r]isks associated with new or more stringent legal mandates that may be imposed at some point within the planning horizon." Additionally, 20 CSR 4240-22.060(3)(C) states that the "utility shall include in its development of alternative resource plans the impact of . . . (1) [t]he potential retirement or life extension of existing generation plants. . . and (2) [t]he addition of equipment and other retrofits on generation plants to meet environmental requirements." Most importantly, Ameren's failure to test the going-forward value of all of its existing units fails to meet the IRP's objective of meeting customer requirements through cost minimization because Ameren's approach has shielded possible lower-cost paths from study.[17]

III. Deficiency 3: Ameren locking in a large-scale natural gas plant in its plan is meritless.

Ameren's new plan includes the installation of a 1,200 MW NGCC plant in 2031; this resource was not selected through model optimization but rather selected by Ameren as a replacement resource for retiring Sioux simultaneously. The Company delayed the original Sioux retirement date of 2028 due to the PVRR analysis and the timing of its ability to install the gas plant.[18] But, as explained above, the PVRR analysis does not provide a definitive result, showing that it would be a mere 0.03 percent more expensive to retire the plant in 2028 instead of 2030. Also, the addition of the gas plant involves assuming that it will be "clean-burning" by 2040 and

[17] 20 CSR 4240-22.010(2)(B).

[18] Company data response to SIERRA-SC 005.

that the plant is needed for reliability; but the former is unfounded, and the latter has not been rigorously supported.

The Company is claiming that the new NGCC will use hydrogen fuel and carbon capture to maintain the Company's CO_2 emission targets of 85 percent reduction by 2040 and net-zero emissions by 2045.[19] However, the costs associated with adopting these new technologies were not included in its modeling.[20] Ameren claims that it assumed that hydrogen would cost the same as natural gas, but there is no evidence provided for that assumption. Costs for storage, transmission, distribution of hydrogen fuel are not included: the Company is essentially assuming that the plant will be ready to burn hydrogen at no extra cost. It is a similar story for carbon capture storage ("CCS"): there are no costs for adopting this practice at the plant in the Company's modeling.[21] The Company's assumption that this resource can become "clean burning" at no cost is unrealistic on its face, and it undercuts the Company's locking in of the new gas plant instead of proven clean technologies with known costs.

The IRP Change's reliability analysis was conducted by Astrapé Consulting and used by Ameren to justify the need for the new NGCC; but the analysis of reliability is incomplete and there was no further documentation or support for its findings other than what Ameren provided in the IRP Change. The Astrapé analysis looks at the reliability impacts of new resource additions and retirements, including a direct comparison of new gas versus battery storage.[22] The analysis showed the "benefit from additional battery storage" assuming a four-hour battery,

[19] Ameren Missouri 2022 Change in Preferred Plan IRP, p. 3.

[20] Ameren Missouri 2022 IRP Preferred Plan Change Stakeholder Discussion, July 13, 2022.

[21] *Id*.

[22] Ameren Missouri 2022 Change in Preferred Plan IRP, p. 17-18.

concluding that achieving reliability with these four-hour batteries and renewables was "increasingly more costly" and "dependent on significant improvements in battery storage technology."[23] One possible solution is to evaluate long-duration battery storage, which the Company does mention but does not provide a quantitative analysis of it in the IRP Change. When asked in the stakeholder meeting if Astrapé evaluated longer-duration batteries, Ameren said that it looked at 8- and 24-hour batteries as well. But the reliability analysis does not show an analysis of these battery types, instead focusing on four-hour batteries and dismissing them in favor of new gas. Moreover, the Company stated that there was no further documentation for the reliability analysis, so any work Astrapé did involving longer-duration batteries is unavailable.[24] The reliability analysis as it is presented in the filing is a strawperson that tries to justify new gas but does not consider viable alternatives to that resource. Because the reliability analysis is incomplete and lacks documentation, it should be ignored or given minimal weight.

The failure to adequately include all costs associated with the gas plant—namely the hydrogen infrastructure needed and costs of carbon capture—and the lack of justification regarding reliability lead one to conclude that Ameren failed to conduct cost minimization planning and failed to find a plan that was "just and reasonable" and in the public interest.[25] To remedy this deficiency, Ameren should revise its analysis to incorporate the potential for longer-duration batteries, and include an estimate of all costs of converting the gas plant to burn cleanly. With the IRA, the costs of these batteries will decrease substantially, making them an attractive capacity alternative.

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[23] *Id*.

[24] Ameren Missouri 2022 IRP Preferred Plan Change Stakeholder Discussion, (July 13, 2022).

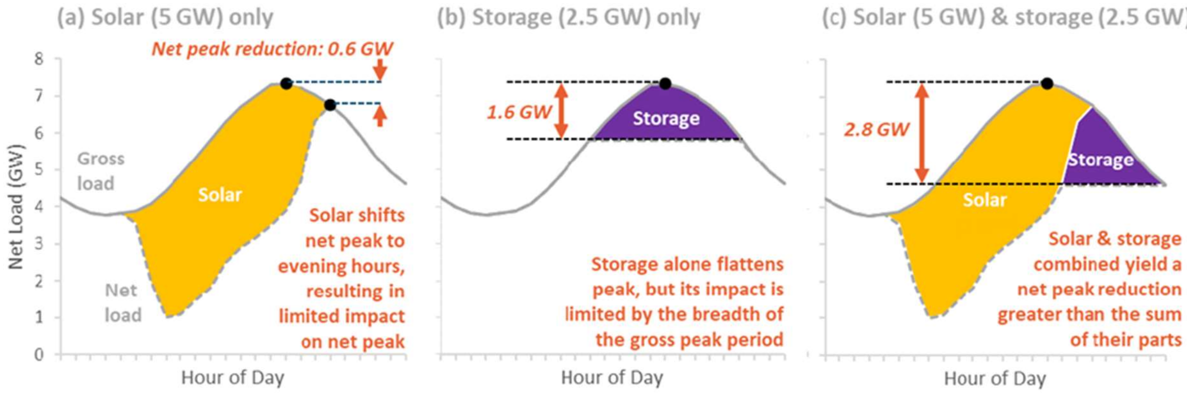
[25] 20 CSR 4240-22.010(2).

IV. Deficiency 4: Ameren needs to take battery storage more seriously as a resource option.

Ameren did not give enough consideration to battery storage, either as a stand-alone or hybrid resource, in its original 2020 IRP filing.[26] Although Ameren did include battery storage in its 2022 IRP filing, its treatment of storage resources is limited in the short- and medium-term with the preferred plan only adding battery storage resources starting in 2035. As mentioned above, the Company also favored new gas with hydrogen and carbon capture (without most of the costs of doing so) to provide reliability but did not provide an analysis of longer-duration battery storage. The preferred plan is also devoid of solar-battery hybrid resources. While both solar and battery resources are becoming more attractive on a cost-basis, they are also mutually beneficial as both an energy and capacity resource when paired together, leading more utilities to these hybrids as replacement resources. For instance, the Public Service Company of New Mexico ("PNM") is replacing its 497 MW share of the San Juan coal plant with solar and battery hybrids, and got approval to do the same for its share of the Palo Verde nuclear plant. PNM illustrated the value and complementarity of solar and battery storage hybrids in providing capacity in Figure 1 below.

[26] Ameren Missouri 2022 Change in Preferred Plan IRP, p. 3.

Figure 1: Value of Solar-Battery Hybrids



Source: Copy of Figure NS-3 from Direct Testimony of Nicolai Schlag, Before the New Mexico Regulation Commission, Case No. 21-04-02-UT, p.11.

The goal of Ameren's IRP process is to achieve the lowest reasonable cost plan given an uncertain future, while achieving other valid policy goals, such as reducing pollution and supporting economic growth. Ameren has not fully explored battery storage as a replacement resource. Longer-duration batteries should be considered, along with solar-battery hybrid resources. Batteries provide valuable grid services and capacity—especially for longer durations such as 8, 10 or 12 hours. Solar-battery hybrids in particular are valuable energy and capacity resources that utilities are increasingly looking to instead of gas replacement resources. Both hybrid and standalone resources also qualify for ITC, the latter type being an important addition of the IRA. With the IRA, these credits will also increase to 30 percent (or higher depending on the two adders) and extended for the next 10 years of installations. While we do not expect Ameren to have anticipated this new law, the failure to adequately include battery resources resulted in an IRP Change that fails to identify the portfolio of resources that meets customer requirements at lowest cost. To remedy this deficiency, Ameren should revise its ARPs to include a robust set of plans with stand-alone storage resources and solar-battery hybrid resources; the costs should also reflect the recent changes in tax credits available to these resources in the IRA.

V. Deficiency 5: Ameren is inflating the costs of solar PV and wind.

Ameren has added a substantial premium to the costs of solar PV and wind that disadvantages these resources in the modeling.[27] Despite recent inflationary pressures, the long-term outlook for solar PV and wind is still low-cost and Ameren has not provided supporting documentation for this premium; it merely stated that it used 2020 RFP results, whereas we are now in the second half of 2022.[28] As a foundation, Ameren used the National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") from 2021 then added a premium on these costs through 2030 in order to "ensure consistency with current market costs."[29] However, the 2022 NREL ABT shows a more accurate and even lower forecast for solar costs than the 2021 forecast basis used by the Company: on average from 2022-2030, the capital costs are 9 percent lower.[30] The cost for wind barely changed between the two forecasts: they are 1 percent higher for the same period. Ameren's addition of a large premium on these resources contradicts the more-recent outlook from its source and contradicts the outdated source that it used to tack on a premium.

The IRA will put further downward pressure on solar PV and wind costs that has not been accounted for in the latest forecasts from NREL. The new bill increases the current tax

[27] Ameren Missouri 2022 Change in Preferred Plan IRP, p. 12.

[28] Company data response to SIERRA-SC 004.

[29] *Id.*

[30] NREL 2021 and 2022 ATB: https://atb.nrel.gov/electricity/2022/index and https://atb.nrel.gov/electricity/2021/data. (Note that 2021 ATB is in 2019 dollars and 2022 ATB is in 2020 dollars; thus, comparisons between the two need to account for inflation from 2019 to 2020.).

credits for solar PV and wind—the ITC and PTC, respectively—extends these credits for 10 years, and offers incentives for domestic manufacturing and location near retired coal sites.[31] While Ameren did not have this knowledge at the time of its IRP Change, this recent development runs counter to the Company's treatment of these resources' costs. In order to remedy this deficiency in cost minimization and finding a plan that is in the public interest, the Company should remove its premium on solar and wind costs, and incorporate the IRA tax credits in its modeling.

VI. Deficiency 6: Ameren only modeled self-build resources, despite the potential savings from PPAs.

Ameren should have modeled power purchase agreements ("PPAs") in its IRP, rather than assume that all new resources were built by the Company, and therefore put into ratebase.[32] It is unrealistic to ignore the option that a third-party could build (and possibly operate) replacement resources in the future. Unfortunately, by failing to model PPAs, Ameren has failed to adhere to the IRP rule's goal of including plans with "substantively different mixes of supply-side resources," as well as their "robustness under a broad range of conditions."[33] This approach also harms the Company's ability to minimize costs for utility customers.

Further, Ameren's assumption that new renewable and storage resources were all self-build could be disadvantageous to these resources in calculating the portfolios' net present value. A PPA is typically structured on a levelized cost basis, sometimes with a percentage escalation,

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[31] *See* Mona Dajani, "Diving into the Inflation Reduction Act's tax credits and the ambitious plan to reshape the US energy sector," Utility Dive (August 9, 2022), available at https://www.utilitydive.com/news/diving-into-the-inflation-reduction-acts-tax-credits-and-the-ambitious-pla/629075/

[32] Ameren Missouri 2022 IRP Preferred Plan Change Stakeholder Discussion, July 13, 2022.

[33] 20 CSR 4240-22.060(3).

whereas a self-build resource would have much higher costs in earlier years than in later years due to the decreasing ratebase and rate of return. In order to capture more realistic procurement of future PPAs, Ameren should have structure some of the new resources in its model as PPAs—whereas currently it is overstating the costs of these resources to customers. In addition, Ameren assumes that the credits from the ITC are "normalized" over the life of a project for its self-build resources; but renewables and storage PPAs can be cheaper due to how the ITC is built into the price immediately. Notably, the IRA helps remedy the solar normalization for utility-operated resources by letting solar PV projects collect the ITC in the same manner as the PTC, which has been predominantly used for wind resources. If that is indeed allowed, utilities will have the option to recover the solar ITC faster than they currently do.

The failure to adequately assess alternatives to owning new resources resulted in an IRP that fails to identify the portfolio of resources that meets customer requirements at the lowest reasonable cost. To remedy this deficiency, Ameren should model at least some new resources as PPAs, particularly renewable PPAs, for which the Company is more likely to avail itself in the future. For solar and solar-hybrids, the Company should assume that the ITC is immediately built into the price per MWh, as it would be with a PPA. The Company should also model the IRA tax credits for all resource ownership arrangements.

VII. Deficiency 7: Ameren's job impacts analysis was unsupported and should not be used to determine a preferred plan.

In our previous comments on the 2020 IRP, we pointed out that Ameren was overstating the job impacts from new natural gas generation, understating the impacts from new solar PV resources, and failed to adequately support its job impact assumptions. In this IRP Change, the Company has not updated these assumptions, nor has it provided any further justification for these assumptions.[34] Most notably, the Company continues to assume roughly 3 jobs per MW of new gas construction and 0.14 O&M jobs per MW; but real-world examples show impacts are typically closer to 0.7 jobs per MW for construction and 0.03 to 0.05 jobs per MW for the long-term.[35] Thus, the Company is overestimating the job impacts from natural gas by roughly a factor of 3 or 4 times. Moreover, the Commission's rules require Ameren to fully "describe and document" the economic impacts of its alternative resource plans.[36] If the Company is going to report these impacts, it needs to provide updated assumptions that are fully documented; these assumptions also should not bias the impacts towards one resource type.

VIII. Conclusion

Sierra Club appreciates the opportunity to engage in Ameren's IRP process and respectfully requests that the Company agree to prepare, or the Commission order the Company to prepare, a revised IRP filing that corrects the deficiencies identified herein.

Respectfully submitted,

Dated: September 2, 2022

<u>/s/ Bruce A. Morrison</u>
Bruce A. Morrison

[34] Company data response SIERRA-SC 007

[35] Ameren workpaper "Job Summary"; *See* David Wagman, "Automation is Engineering the Jobs Out of Power Plants," IEEE Spectrum (August 3, 2017), available at https://spectrum.ieee.org/energywise/energy/fossilfuels/automation-is-engineering-the-jobs-out-of-power-plants; *See also* Gas to Power Journal, "Groundbreaking takes place for Ohio CCGT project," (30 May 2019), available at https://gastopowerjournal.com/item/9744-groundbreaking-takes-place-for-ohio-ccgt-project; *See also* Rod Walton, "Black & Veatch in JV to build 900-MW CCGT power plant in Canada," Power Engineering (September 22, 2020), available at https://www.power-eng.com/gas/new-projects-gas/black-veatch-in-jv-to-build-900-mw-ccgt-power-plant-in-canada/#gref

[36] 20 CSR 4240-22.060(3), (6).

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Appendix C
Four-Factor Analysis Information

C-1 Four-Factor Analysis Summary

Four Factor Analysis Summary

The Air Program conducted four-factor analyses for the facilities listed in Table 1. On July 29, 2020, the Air Program sent a request letter to each of these facilities to provide four-factor analysis information for several technologies. The following are the list of SO_2 and NO_x control technologies the Air Program requested information on:

SO_2 Control Technologies:

- Flue Gas Desulfurization (FGD) - Wet, Spray Dry, Dry Scrubber (50% to 99%)
  a. Wet Lime Scrubber, typical control efficiency 90% - 99%
  b. Wet Limestone Scrubber, typical control efficiency 90% - 99%
  c. Dual-Alkali Scrubber, typical control efficiency 90%-95%
  d. Spray Dry Absorber (SDA), typical control efficiency 90%-95%
  e. Dry Sorbent Injection(DSI), typical control efficiency 50% - 80%
  f. Circulating Dry Scrubber
  g. Hydrated Ash Reinjection
- Limestone Injection
- Low sulfur content coal
- Fuel Switch

NO_x Control Technologies:

- Selective Catalytic Reduction (SCR), typical control efficiency 90%
- Low NO_x Burners (LNB), typical control efficiency 40% - 60%
- Selective Non-Catalytic Reduction (SNCR), typical control efficiency 35% - 50%
- Overfire Air (OFA), typical control efficiency 20%
- Flue Gas Recirculation (FGR)
- Low Excess Air (LEA)

Ameren-Missouri and Mississippi Lime Company provided full four-factor analyses for their sources. The rest of the facilities provided information that helped the Air Program conduct four-factor analyses for them. In the following paragraphs, the Air Program will provide a summary of cost of control from each facility's four-factor analysis. This Appendix contains the full factor analyses information conducted by the Air Program and all of the four-factor analyses information provided by the facilities listed in Table 1.

*Table 1. Sources Selected for the Four-Factor Analysis **

Company	Site Name	Unit(s)	Class I Area	Pollutants
Ameren Missouri	Labadie Energy Center	(4) coal boilers	Mingo, Hercules	NO_x and SO_2
Ameren Missouri	Rush Island Energy Center		Mingo, Hercules	NO_x and SO_2
Associated Electric Cooperative Inc.	New Madrid Power Plant	(2) coal boilers	Mingo, Hercules	NO_x and SO_2
Associated Electric Cooperative Inc.	Thomas Hill Energy Center	(3) coal boilers	Hercules	NO_x and SO_2
City Utilities of Springfield	John Twitty Energy Center	(2) coal boilers	Hercules	NO_x and SO_2
Sikeston Power Station		(1) Coal boiler	Mingo	NO_x and SO_2
Mississippi Lime Company		(11) Rotary Kilns	Mingo	NO_x and SO_2

*Buzzi and Meramec were removed from the list of Four-Factor sources after further initial evaluations.

Results of the Four-Factor Analysis

Table 2 shows the results of the four-factor analyses for all seven facilities. The control technologies listed in the table are those with the lowest cost effectiveness amongst all feasible control technologies evaluated for the units. All cost effectiveness values are greater than the cost effectiveness thresholds for SO_2 ($3,658) and NO_X ($5,370) per ton removed the Air Program used in the analyses. There are two units, Ameren Labadie Energy Center B4 and John Twitty energy Center B1, which have cost effectiveness for DSI's that are only slightly above the SO_2 cost effectiveness threshold $3,658 per ton removed. The Air Program calculated the DSI control cost of these two and other units based on EPA's spreadsheets and IPM costs for DSI, which are Excel-based tools that can be used to estimate the cost of building and operating pollution control such as SCR, Wet FGD, Dry FGD, DSI, Activated Carbon Injection (ACI) and PM. It should be noted that EPA updated the SO2 control cost manual in April 2021 and the update does not include a methodology to estimate control cost for DSI since it operates by injecting sorbent directly into the furnace or into the ductwork following the furnace, rather than as a separate add-on air pollution control device. Therefore, Missouri determined that potential additional controls are not cost-effective. In addition, all Class I areas impacted by sources in Missouri have made steady and significant improvement in visibility, and EPA's 2028 RH modeling shows they are projected to be below, or well below, their URP glidepaths in 2028. Trends show huge reductions in both NO_X and SO_2 emissions. Additional emissions reductions are expected from the permanent shutdown of coal-fired boilers in Table 42. Given all of these factors, Missouri concludes that on-the-books and on-the-way controls are more than sufficient to achieve reasonable progress goals, and no additional measures are necessary to make reasonable progress in the second implementation period.

Table 2. Summary of Results of the Four-Factor Analysis

Facility	**Unit**	**Pollutant**	**Control Technology**	**Annualized Cost**	**Emission Reduction**	**Effective Cost**
Labadie Energy Center	B1	SO_2	DSI	$27,685,665	7,011	$3,949
		NO_x	SNCR	$4,076,383	450	$9,059
	B2	SO_2	DSI	$27,685,665	7,031	$3,938
		NO_x	SNCR	$4,076,383	450	$9,059
	B3	SO_2	DSI	$27,066,155	6,592	$4,106
		NO_x	SNCR	$6,667,151	425	$15,687
	B4	SO_2	DSI	$27,066,155	6,854	$3,949
		NO_x	SNCR	$6,667,151	425	$15,687
Rush Island Energy Center	B1	SO_2	DSI	$29,791,843	6,831	$4,361
		NO_x	SNCR	$4,615,720	375	$12,309
	B2	SO_2	DSI	$29,863,554	7,337	$4,070
		NO_x	SNCR	$4,615,720	375	$12,309
Mississippi Lime Company	EP-069 EP-070 EP-071	SO_2	DSI	$1,009,156	12	$86,900
		NO_x	SNCR	$465,644	24	$19,100
	EP-640 EP-645	SO_2	DSI	$1,374,281	9	$159,500
		NO_x	SNCR	$809,506	85	$9,500
	EP-180H EP-186N EP-187N	SO_2	Wet Lime Scrubber	$1,671,371	171.09	$9,800
New Madrid Power Plant	B1	SO_2	DSI	$22,468,782	5,025	$4,471
	B2	SO_2	DSI	$23,697,083	5,561	$4,261
Thomas Hill Energy Center	B1	SO_2	DSI	$9,872,153	1,837	$5,375
	B2	SO_2	DSI	$14,066,230	2,867	$4,906
	B3	SO_2	DSI	$30,732,055	7,698	$3,992
John Twitty Energy Center	B1	SO_2	DSI	$8,274,202	1,794	$4,612
Sikeston Power Station	B1	SO_2	DSI	$14,241,557	3,443	$4,136
		NO_x	SCR	$10,792,100	774	$13,947
Labadie Energy Center*	B1	SO_2	DSI	$27,074,061	7,011	$3,862
		NO_x	SNCR	$3,261,106	450	$7,247
	B2	SO_2	DSI	$27,074,061	7,031	$3,851

Facility	Unit	Pollutant	Control Technology	Annualized Cost	Emission Reduction	Effective Cost
		NO_x	SNCR	$3,261,106	450	$7,247
	B3	SO_2	DSI	$25,419,801	6,592	$3,856
		NO_x	SNCR	$3,333,575	425	$7,844
	B4	SO_2	DSI	$25,419,801	6,854	$3,709
		NO_x	SNCR	$3,333,575	425	$7,844
Rush Island Energy Center*	B1	SO_2	DSI	$28,751,220	6,831	$4,209
		NO_x	SNCR	$3,000,218	375	$8,001
	B2	SO_2	DSI	$28,822,931	7,337	$3,928
		NO_x	SNCR	$3,000,218	375	$8,001
Mississippi Lime Company*	EP-069 EP-070 EP-071	SO_2	DSI	$984,041	11.61	$84,800
		NO_x	SNCR	$465,644	24	$19,100
	EP-640 EP-645	SO_2	DSI	$1,344,685	8.62	$156,000
		NO_x	SNCR	$809,506	85	$9,500
	EP-180H EP-186N EP-187N	SO_2	Wet Lime Scrubber	$1,632,862	171.09	$9,500
New Madrid Power Plant*	B1	SO_2	DSI	$20,268,773	5,025	$4,033
	B2	SO_2	DSI	$22,003,761	5,561	$3,957
Thomas Hill Energy Center*	B1	SO_2	DSI	$8,255,270	1,837	$4,494
	B2	SO_2	DSI	$12,245,800	2,867	$4,271
	B3	SO_2	DSI	$29,936,230	7,698	$3,889
John Twitty Energy Center*	B1	SO_2	DSI	$6,764,511	1,794	$3,771
Sikeston Power Station*	B1	SO_2	DSI	$13,532,594	3,443	$3,930
		NO_x	SCR	$7,899,846	774	$10,209

* Cost estimates based on remaining useful life based on EPA's control cost manuals

Consent Agreement with Four-Factor Sources to Maintain Reasonable Progress Goal

The Air Program and all facilities selected for four-factor analyses except Mississippi Lime Company have entered into consent agreements to help set and maintain reasonable progress goals (RPG) for both Class I areas in Missouri. These consent agreements are in Appendix E. In these consent agreements, the Air Program required that each facility's future fuel purchase shall be western sub-bituminous coal. In addition, each facility agreed to run any exiting control devices at all times when burning coal in the boiler(s) except during periods of start-up, shutdown, or malfunction pursuant to 10 CSR 10-6.050. With these consent agreement, the Air Program required two facilities to run their exiting SCRs when burning coal. As discussed above, these two facilities were not operating their SCRs all the times. This will help reduces NOx emissions further and hence lower the 2028 RPGs for both Class I areas as will be discussed in Chapter 5 of this document.

C-2 John Twitty Energy Center Four-Factor Analysis

John Twitty Energy Center-Factor Analysis

Introduction

The Regional Haze Rule requires that states develop and implement comprehensive plans to reduce human caused regional haze in designated Class I areas located within the state, and for each Class I area located outside the state which may be impacted by air emissions from Missouri. Hercules-Glades Wilderness Area and Mingo Wilderness Area are the two Class I areas in Missouri. This long term strategy to reduce regional haze is codified in 40 CFR 51.308(f)(2)(i), requiring states to evaluate and verify if controls on emission sources are necessary, with the goal of returning targeted areas to their natural visibility conditions by 2064. Under the current 2017 Regional Haze Rule, the second planning period is being addressed, with it beginning in 2019 and progressing through 2028. The goal of the second planning period is a phased-strategy toward meeting objectives of the 2064 target year. In this strategy, states have an obligation to consult with the relevant federal land managers during the plan development process, which could include the National Park Service, the U.S. Forest Service, the Bureau of Land Management, and others. Section 169A(g) of the Clean Air Act (CAA) requires the state to assess four factors when considering potential control measures: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of any source evaluated. The Missouri Department of Natural Resources' Air Pollution Control Program (Air Program) focused its four factor analysis strategy on stationary point source emissions of nitrogen oxide (NO_x) and sulfur dioxide (SO_2) for the second planning period because these are the principal anthropogenic pollutants influencing Class I visibility in both Missouri and prospective nearby states. The Air Program conducted a screening analysis for point sources by pairing 2016 emissions over distance with combined sulfate and nitrate extinction-weighted residence times (EWRT) meeting a one percent threshold to determine which sources would be evaluated for controls based on the four factor analysis to meet the Regional Haze Rule Reasonable Progress Goals (RPG). If a source was selected for a four factor analysis, further evaluation was necessary to determine potentially available emission reduction measures listed in 40 CFR 51.308(f)(2), taking into consideration the U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*. Additionally, the Air Program used EPA's updated 2028 Regional Haze Modeling to estimate visibility conditions at the end of the second planning period in 2028. According to this modeling, both Missouri Class I areas' 2028 RPGs are below the Uniform Rate of Progress (URP) and hence meet the goals for the regional haze second planning period. Subsequently, Missouri meets the goals for the regional haze rule second planning period without adjusting the URP to account for impact from anthropogenic sources outside the United Sates, as the regional haze for the second planning period includes a provision that allows states to propose an adjustment.

Facility Description

The John Twitty Energy Center (JTEC) is owned and operated by City Utilities of Springfield, located in Greene County, Missouri. City Utilities of Springfield is a community owned utility providing service to over 106,000 customers in southwest Missouri with electricity, natural gas, water, and other services since 1945. The utility is owned by the public and overseen by an eleven member Board composed of local citizens. City Utilities of Springfield produces electric power through use of natural gas at the James River Power Station, JTEC, and the McCartney generating station, with power also being produced at the

Noble Hill Landfill by landfill gas. JTEC also produces power from two coal fired units. The two coal fired units are the focus of this analysis as verified through screening, although there are additional emission sources at the facility.

The two JTEC facility coal fired units are both boilers. Unit 1 is a Riley Stoker Turbo coal fired steam generator which was installed in 1976, fires up to 1,810 million British thermal units per hour (mmBtu/hr) of fuels and is designed to burn a combination of coal, pipeline natural gas and fuel oil No. 2. Unit 2 is a Foster-Wheeler dry-bottom, opposed-fired, natural circulation pulverized coal fired steam generator which was installed in 2011, fires up to 2,724 mmBtu/hr of fuels and is designed to burn a combination of coal and pipeline natural gas. The following table summarizes the emission controls currently in place for Units 1 and 2:

	Unit 1	Unit 2
SO_2	Powder River Basin low sulfur coal	Powder River Basin low sulfur coal Dry Lime Injection Fluidized Bed Scrubber (Best Available Control Technology – BACT); control efficiency of 85 to 90 percent
NO_x	Selective Catalytic Reduction (BACT); control efficiency of 70 to 75 percent	Low NO_x Burners/Over-Fired Air Selective Catalytic Reduction (BACT) ; control efficiency of 80 to 85 percent
PM/Mercury	Pulse jet fabric filter baghouse (BACT) and powdered activated carbon injection system; control efficiency of 99.8 percent for PM	Pulse jet fabric filter baghouse (BACT) and NALCO's MerControl SD-Hg to control mercury; control efficiency of 99.9 percent for PM

The facility utilizes low sulfur subbituminous Powder River Basin coal to produce electricity from these two units. Both units are subject to the Mercury Air Toxics Standards (MATS) rule as codified at 40 CFR Part 63 Subpart UUUUU. In this rule, SO_2 emission limits for coal fired electric generating units such as JTEC Unit 2 with add-on flue gas desulfurization (FGD) were set at 0.20 lbs/mmBtu on a 30-day rolling average, and hydrogen chloride limits at 0.0020 lbs/mmBtu. The emission limits reflect the maximum achievable control technology for existing units. Additionally, EPA's recent *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*,[1] presents a basis on how to address sources that currently have a scrubber already installed. In the EPA guidance, Step 3., Selection of Sources for Analysis, under segment f), Sources that already have effective emission control technology in place, articulates the following:

[1] U.S. Environmental Protection Agency, *Guidance on Regional Haze State Implementation Plans for the Second Implementation Period*, (Research Triangle Park, 2019).

> For the purpose of SO_2 control measures, 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. The two limits in the rule (0.2 lb/MMBtu for coal-fired EGUs or 0.3 lb/MMBtu for EGUs fired with oil-derived solid fuel) 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.

JTEC Unit 2 has elected and continuously complies with the SO_2 emission limits, therefore meeting those requirement of MATS and can be considered maximum achievable control technology for SO_2 control. As a result of this, Unit 2 has been removed from further analysis for SO_2 emission controls.

Baseline SO_2 and NO_x Emissions

The first step in developing this four factor analysis was to determine the baseline SO_2 and NO_x emissions for Unit 1 and Unit 2 respectively. The averaging period from January 1, 2015 through December 31, 2020 was used because it represents the latest complete annual emissions reported for each of these sources. Baseline annual SO_2 and NO_x emissions for these two units was obtained from continuous emission monitoring systems data contained in EPA's Clean Air Markets Division through their Air Markets Program Data.[2] Using baseline annual emissions information for the years 2015, 2016, 2017, 2018, 2019, and2020, average pounds per hour, and average heat input were established. The following table summarizes the SO_2 and NO_x baseline emissions for JTEC Units 1 and 2.

Facility source	Air Contaminate	Average pounds per hour (lb/hr)	Average tons per year (tpy)	Average million British thermal units per year (mmBtu/year)	Timeframe
Unit 1	SO_2	789	1,998	7,279,642	Emissions based on 36-month annual average (1/1/15-12/31/20)
	NO_x	140	353		
Unit 2	SO_2	153	550	13,742,825	Emissions based on 36-month annual average (1/1/15-12/31/20)
	NO_x	135	487		

Sulfur Dioxide Emission Controls

<u>Coal Washing</u>

Coal washing, also known as coal cleaning or coal beneficiation, involves separating out impurities from coal in a liquid medium and can include processes to remove ash, sulfur and moisture. The liquid medium may be combined with finely ground heavier minerals to achieve better separation of unwanted rock and mineral material from coal particles. Washing operations are carried out after coal is

[2] U.S. Environmental Protection Agency, Clean Air Markets Division, Air Markets Program Data, 2021.

sized, then a number of different washing techniques are used depending on coal particle size, the type of coal, and the required level of preparation. The coal is next dewatered with the waste streams discarded. Although typically used for bituminous and anthracitic coals, subbituminous and lignite coals are more difficult to separate out mineral material and coal washing is more infrequent. Therefore, this technology was not further evaluated.

Coal Switching

An option for reducing SO_2 emissions is to reduce the sulfur content of the coal. Reducing the amount of sulfur in the coal inhibits the amount released during the combustion process, and would decrease the amount of SO_2 introduced further in the system. JTEC burns western subbituminous coal, with an average sulfur content in the range of 0.17 to 0.44.[3] Because of the inherently low sulfur content of the coal used by the facility, fuel switching will not be further evaluated.

Dry Sorbent Injection (DSI)

Dry Sorbent Injection systems involve the injection of a dry sorbent into the flue gas ductwork following the boiler to reduce concentrations of the acid gases SO_2, hydrogen chloride and hydrogen fluoride which are regulated to prevent sulfur emissions. Sulfur oxides typically react directly with the dry sorbent, which are collected in a downstream particulate control device. The injection of hydrated lime, trona, or sodium bicarbonate into the flue gas for the removal of SO_2 and sulfur trioxide is a proven solution to reduce sulfur emissions. DSI is a system that is capable of between 25 to 80 percent SO_2 removal, and higher with a fabric filter. Advantages of this control mechanism include lower capital cost, less corrosion, and a smaller footprint to those of other technologies. In comparison to other systems, the lower capital costs result in higher operating costs for equivalent SO_2 removal rates.

Unit 1 at the facility currently has in place a Powdered Activated Carbon injection system for the Mercury and Air Toxics Standards rule. DSI's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at JTEC Unit 1.

Spray Dryer Absorber (SDA) Flue Gas Desulfurization (FGD)

Spray Dryer Absorber Flue Gas Desulfurization technology operates using absorption as the prevalent collection mechanism. In general, the acid gas dissolves into the alkaline slurry droplets and then reacts with the alkaline material to form a filterable solid. Contact between the alkaline sorbent, usually hydrated lime, and flue gases make the gas removal process effective. The lime slurry is then atomized into droplets within the gas stream. The fine spray provides a high contact area in order for gas absorption to occur. Acid gases are then absorbed onto the atomized droplets. Evaporation of the slurry water in the droplets occurs at the same time as the acid gas absorption. The cooled flue gas then carries the dried reaction product downstream to the fabric filter. This dried reaction product can be recycled to optimize lime use. SDA FGD systems can have between a 70 to 90 percent SO_2 removal efficiency.

[3] U.S. Energy Information Administration, EIA-923; EIA923_Schedules_2_3_4_5_M_12_2019_Final; Page 5 Fuel Receipts and Costs; Fuel Receipts and Cost Time Series File, 2015, 2016, 2017, 2018, 2019, 2020 Final.

Unit 1 at the facility currently has in place a Powdered Activated Carbon injection system for the Mercury and Air Toxics Standards rule. SDA FGD’s have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at JTEC Unit 1.

Wet FGD

In a Wet Flue Gas Desulfurization system, flue gas is channeled to a spray tower where a fluid slurry of sorbent is injected into the flue gas. The nozzles and injection locations are designed to optimize the size and density of slurry droplets formed by the system to provide good contact between the waste gas and sorbent. Part of the water in the slurry is evaporated and the waste gas stream becomes saturated. Sulfur dioxide dissolves into the slurry droplets where it reacts with the alkaline particles. The slurry falls to the bottom of the absorber where it is collected. Treated flue gas passes through a mist eliminator and then exits the absorber to remove any caught slurry droplets. The effluent is sent to a reaction tank where the SO_2/alkali reaction is completed forming a neutral salt. After passing through the tank, systems dewater the used slurry for disposal or use as a byproduct. Most wet scrubbers have removal efficiencies in excess of 90 percent, however a typical range is from 80 to 98 percent.

Unit 1 at the facility currently has in place a Powdered Activated Carbon injection system for the Mercury and Air Toxics Standards rule. Wet FGD’s have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at JTEC Unit 1.

Nitrogen Oxide Emission Controls

Low NO_x burners and Overfire Air

Low NO_x burners are used by many utilities throughout the country for both new and retrofit applications. Low NO_x burners limit NO_x formation by influencing the stoichiometric and temperature profiles of the combustion process in each burner flame. This type of control is accomplished due to machinery designs that stabilize the distribution and mixing of the fuel and air. As a result, O_2 is reduced in the primary combustion zone, there is a reduced flame temperature, and a there is a reduced residence time at peak temperature, all of which limit the formation of NO_x.

Many facilities across the country use a combination of low NO_x burners and overfire air to reduce NO_x emissions. Overfire air is a combustion control technique that diverts a percentage of the total air combusted away from the burners and injects it through valves above the top burner levels, leaving the total amount of combustion air fed to the furnace unchanged. NO_x emissions are limited by retraining NO_x formation by moderately delaying and extending the combustion process. The outcome is less intense combustion and reduced flame temperatures. Emissions are also limited by lessening the concentration of air in the burner combustion zone where volatile fuel nitrogen develops.

Unit 1 at the facility previously had Inherently Low NO_x Burners installed, however they are not in operation, and is currently operating a selective catalytic reduction system with a control efficiency of 70 to 75 percent and is considered the best available control technology (BACT). Therefore, Low NO_x Burners with Overfire Air were not considered further for evaluation.

Unit 2 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 80 to 85 percent and is considered BACT. This unit also is equipped with Low NO_x Burners/Overfire Air to control NO_x. Because the unit already has SCR equipment installed along with Low NO_x Burners/Overfire Air, no further evaluation will be prepared at JTEC Unit 2.

Selective NonCatalytic Reduction (SNCR)

A Selective NonCatalytic Reduction system converts NO_x into nitrogen and water by injecting reagents at high temperature without the need of a catalyst. The system can achieve high reduction rates without the use of additional catalyst if the process is set at the correct temperature range. In this system, the ammonia or urea reagents, are injected directly into the existing flue gas pipe flow using water as a carrier in order to cover the entire cross section in the correct temperature range. This system can be an economical form of NO_x reducing technology and works for applications where a modest NO_x reduction of about 30 to 40 percent is required along with tight schedules where the flue gas temperatures are high enough (895°C-1100°C) to promote the reactions. SNCR systems reduce NO_x emission in a range from 30 to 60 percent.

Unit 1 at the facility previously had Inherently Low NO_x Burners installed, however they are not in operation, and is currently operating a selective catalytic reduction system with a control efficiency of 70 to 75 percent and is considered the best available control technology (BACT). Because this unit currently has a selective catalytic reduction system, a SNCR was not further evaluated.

Unit 2 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 80 to 85 percent and is considered the BACT. Because this unit currently has a selective catalytic reduction system, a SNCR was not further evaluated.

Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction technology is a proven and effective method to reduce NO_x emissions from coal fired power plants. In general, all through the combustion process, the nitrogen that occurs naturally in the coal, and the nitrogen and oxygen existing in the combustion air, combine to form NO_x. Before being released to the atmosphere, the exhaust gas proceeds through a large catalyst where the NO_x reacts with the catalyst and ammonia and is converted to nitrogen and water. Selective catalytic reduction typically removes between 75 to 85 percent of the NO_x that is in the exhaust gas of a coal-fired power plant, and can be as high as 90 percent.

Unit 1 at the facility previously had Inherently Low NO_x Burners installed, however they are not in operation, and is currently operating a selective catalytic reduction system with a control efficiency of 70 to 75 percent and is considered the best available control technology (BACT). Because the unit already has SCR equipment installed, no further evaluation will be prepared.

Unit 2 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 80 to 85 percent and is considered BACT. Because the unit already has SCR equipment installed, no further evaluation will be prepared.

The following table summarizes both the technologies that have been eliminated and evaluated for further study as discussed above and the expected control efficiency.

Technology	Evaluated Further	Assumed Control Efficiency (%)
Coal Washing	No, Unit 1 No, Unit 2	-
Coal Switching	No, Unit 1 No, Unit 2	-
Dry Sorbent Injection	Yes, Unit 1 No, Unit 2	90
Spray Dryer Absorber Flue Gas Desulfurization	Yes, Unit 1 No, Unit 2	~90
Wet Flue Gas Desulfurization	Yes, Unit 1 No, Unit 2	~95.5
Low NO_x Burners/Overfire Air	No, Unit 1 No, Unit 2	-
Selective NonCatalytic Reduction	No, Unit 1 No, Unit 2	-
Selective Catalytic Reduction	No, Unit 1 No, Unit 2	-

Four Factor Analysis

Costs of Compliance

Cost assessments for the control technologies evaluated were made utilizing the EPA Air Pollution Control Cost Manual Section 4, NO_x Controls, updated in 2019, and Section 5, SO_2 and Acid Gas Controls, updated in 2021. Estimates were obtained by completing spreadsheets for SO_2 controls using EPA's Air Pollution Control Cost Manual. The complete costs derived from the Cost Manual may be found in the appendices for Unit 1. The Capital Recovery Factor (CRF) was based on an interest rate of 3.25 percent and the unit'suseful life for Unit 1. A typical overall lifespan for an electric generating unit of 55 years was used, however there is no enforceable shutdown date codified for this unit.[4] Cost estimates derived from the spreadsheet were converted to 2021 dollars. A summary of the control technologies further evaluated with costs and effectiveness is contained in the following table. The table shows the estimated cost of control for each selected control technologies and remaining useful life scenario as discussed in the main SIP document. The last column shows that the cost effectiveness of all control technologies exceed the cost effectiveness threshold of $3,658 per ton.

For DSI, the Air Program assumed that the facility will utilize milled Trona along with the existing baghouse. According to the facility, adding DSI will require more baghouse maintenance. DSI will almost double the inlet grain loading which will require almost double the bag pulsing. Therefore, bag life will be cut in half from 6 years to 3. The facility's last bag replacement cost exceeded $770,000. In addition, DSI will negatively affect fly ash salability. The facility provided fly ash sales from 2016 to 2021, excluding 2020 year which had unplanned outage. The average ash sales for 2016-2021 is $221,800 per year. The Air Program take into consideration both the replacement cost of the baghouse and the lost revenue

[4] U.S. Energy Information Administration, EIA-860; 3_1_Generator_Y2019; Retired and Canceled; 2015, 2016, 2017, 2018, 2019 Form EIA-860 Data - Schedule 3, 'Generator Data' (Retired & Canceled Units Only).

from selling the fly ash in the control cost analysis. Finally, the Air Program used 2021 CEPCI to project to control cost from 2016.

NO_x and SO_2 Control Costs and Effectiveness

Control Equipment	Boiler	Control Efficiency (%)	Remaining Useful Life (year)	Capital Costs	Annualized Costs	Emission removal (ton)	Cost Effectiveness (2021$/removed ton)
Wet FGD	Unit 1	95.5	8.0	$174,491,516	$30,746,244	1,904	$16,152
SDA	Unit 1	90	8.0	$150,832,974	$26,441,410	1,794	$14,739
DSI with Baghouse	Unit 1	90	8.5	$19,481,221	$8,294,436	1,794	$4,624
Wet FGD*	Unit 1	95.5	25	$174,491,516	$15,914,466	1,904	$8,360
SDA*	Unit 1	90	25	$150,832,974	$13,620,607	1,794	$7,593
DSI with Baghouse*	Unit 1	90	25	$19,481,221	$6,784,745	1,794	$3,782

Time Necessary for Compliance

The time necessary for compliance is the period needed for full implementation of the evaluated feasible control options. This would include the time needed to develop and finalize the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. Estimates for compliance ranged from 30 months for Dry Sorbent Injection, and 52 months each for Spray Dryer Absorber Flue Gas Desulfurization, and Wet Flue Gas Desulfurization.

Energy Impacts

Dry Sorbent Injection: DSI systems would require auxiliary power at the plant by use of electricity to operate fans, pumps, and other equipment. Additional fuel would be expended at the facility to produce this electricity. Additionally, there would be a heat rate penalty associated with this technology.

Spray Dryer Absorber Flue Gas Desulfurization: Lime used in dry FGD systems must be hydrated prior to use, increasing the facility's overall consumption of electricity.

Wet Flue Gas Desulfurization: The primary energy impacts of the wet FGD alternative consists of the additional electrical load resulting from pumps and reagent preparation. As a result, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output.

Non-Air Quality Environmental Impacts of Compliance

Dry Sorbent Injection: This technology would require additional precautions for fuel handling and waste systems to prevent non-air environmental impacts due to increased effluents in wastewater discharges and storm water runoff.

Spray Dryer Absorber Flue Gas Desulfurization: Using this control technology would require the facility to handle limestone for injection in the unit, and pebble lime for use in the dry scrubber. The lime used in this technology would need to be hydrated prior to use, raising the facility's overall water usage. If polluted water is released from the facility, wastewater treatment may be necessary.

Wet Flue Gas Desulfurization: This technology would increase calcium sulfate solids disposal. Typically solid wastes generated using this technology are dewatered and disposed of in landfills. Some of these control systems may be able to generate a gypsum byproduct that can be sold in the open market. If the gypsum cannot be sold, proper disposal would then be required. Significant water use for this technology may require treatment before being discharged in order to meet water effluent limits.

Summary

In conclusion, based on a review of possible and feasible options to reduce SO_2 and NO_x emissions at Unit 1, the Air Program has determined that there are no cost-effective methods of SO_2 and NO_x reduction for this facility. All Class I areas impacted by sources in Missouri have made steady and significant improvement in visibility, and modeling shows they are projected to be below, or well below, their uniform rate of progress (URP) glidepaths in 2028. Based on the four factor analysis completed in this report, the Air Program is proposing to maintain current operational practices consistent with the parameters and limits in JTEC Air Pollution Control Title V Permit to Operate.

**All control cost estimate calculations for wet FGD, SDA, and DSI for both remaining useful life (RUL) scenarios are provided in the attached spreadsheets

John Twitty Unit 1 SO2 DSI cost-data-from-facility-Original-RUL.xlsx
John Twitty Unit 1 SO2 DSI cost-data-from-facility-EPA-RUL.xlsx
John Twitty Unit 1 SO2 SDA-Original-RUL.xlsm
John Twitty Unit 1 SO2 SDA-EPA-RUL.xlsm
John Twitty Unit 1 SO2 wet_FGD-Original-RUL.xlsm
John Twitty Unit 1 SO2 wet_FGD-EPA-RUL.xlsm

From: David Little
To: Leath, Mark
Cc: Basham, Aaron; Alsharafi, Adel; Daniel Hedrick; Clay Dodson; Kelly Turner; Gerad Fox; Bailey Fowler; Kevin Cline
Subject: RE: CU Regional Haze call follow-up
Date: Friday, January 21, 2022 1:55:23 PM
Attachments: John Twitty Unit 1 SO2 DSI cost.xlsx

Mark,

City Utilities submits this email to complete the follow-up items from the November 30, 2021, DNR/CU call. In that call, DNR had three main requests for Unit 1, among other discussion points. The three main requests were to update the DSI cost per ton analysis, the remaining life, and the lack of numeric emission limits. CU's response to the third item was included in our December 1. This email addresses the other two items.

DSI cost analysis
An updated cost analysis using the DNR requested Sargent & Lundy calculator is attached. The updated cost per ton of SO2 removed is approximately $4200. This value carries the following important caveats,

- A retrofit cost factor of 1 was used. However, the cost analysis for Aurora Chena Power Plant used a factor of 1.5, which raises the cost.
- The latest available CEPCI value is 750 from September 2021. However, Q4 2021 saw record inflation. Inflation is at a 40 year high. Therefore a higher index is expected, which raises the cost.
- Costs the calculator does not capture –
    - Adding DSI will require more baghouse maintenance. DSI will almost double the inlet grain loading which will require almost double the bag pulsing. Bag life will be cut in half from 6 years to 3. The last bag replacement cost exceeded $770,000.
    - DSI will negatively affect fly ash salability. Currently, the fly ash is 100% marketed for beneficial reuse. DSI (sodium based) will virtually eliminate this revenue, thus resulting in a higher cost on top of a new disposal cost.
    - At least two additional ash hauling trucks would be needed at a cost of over $300,000 each.

Remaining Life
The estimated coal retirement date in the cost calculator has been updated to 2031. A previous IRP mentioned a different date. However, it was not intended to commit to a retirement date or to a future generation mix. Given changes in the power generation market, fuel costs, etc. evaluation of future generation scenarios is ongoing. City Utilities is updating our IRP to incorporate current industry conditions and determine the appropriate retirement date. The 2031 date in the calculator does not supersede the existing IRP date. The 2031 date was quickly developed only for purposes of the cost calculator and does not represent CU's official position. 2031 is subject to change at any time.

Thank you,
David Little, PE
Engineer III - Environmental

City Utilities of Springfield, MO
417.831.8532

City Utilities

City Utilities

PO Box 551 | Springfield, MO 65801-0551
cityutilities.net

From:	David Little
To:	Leath, Mark
Cc:	Basham, Aaron; Alsharafi, Adel; Daniel Hedrick; Clay Dodson; Kelly Turner; Gerad Fox; Kevin Cline
Subject:	CU Regional Haze call follow-up
Date:	Wednesday, December 1, 2021 12:22:17 PM
Attachments:	image001.png

Mark,

On yesterday's call I mentioned EPA's July memo described a steady-state situation as one in which an emission limit may not be necessary. After re-reading the paragraphs, the language actually goes one step further and details requiring the emission control device itself may not be necessary to make reasonable progress. The Unit 1 SCR and NOx emissions have operated at a controlled-steady state for several years, and CU plans to continue as such. Therefore, the conclusion can be drawn that SIP-required operation of the SCR may not be necessary, let alone setting of an emission limit. Here is the page 9 excerpt for your consideration. We will compile responses to the other items and look forward to submittal by mid-January as discussed.

> However, there may be circumstances in which a source's existing measures are not necessary to make reasonable progress. Specifically, if a state can demonstrate that a source will continue to implement its existing measures and will not increase its emission rate, it may not be necessary to require those measures under the regional haze program in order to prevent future emission increases. In this case, a state may reasonably conclude that a source's existing measures are not necessary to make reasonable progress and thus do not need to be included in the SIP. A determination that a source's existing measures are not necessary to make reasonable progress should be supported by a robust technical demonstration. This empirical, weight-of-evidence demonstration should be based on data and information on (1) the source's past implementation of its existing measures and its historical emission rate, (2) the source's projected emissions and emission rate, and (3) any enforceable emissions limits or other requirements related to the source's existing measures.
>
> Information on a source's past performance using its existing measures may help to inform the expected future operation of that source. If either a source's implementation of its existing measures or the emission rate achieved using those measures has not been consistent in the past, it is not reasonable to assume that the source's emission rate will remain consistent and will not increase in the future. To this end, states should include data for a representative historical period demonstrating that the source has consistently implemented its existing measures and has achieved, using those measures, a reasonably consistent emission rate.[23] For most sources, data from the most recent 5 years (if available) is sufficient to make this showing. Information pertinent to a source's implementation of its existing measures going forward is also critical to a state's demonstration. States should provide data and information on the source's projected emission rate (*e.g.*, for 2028), including assumptions and inputs to those projections. States should justify those assumptions and inputs and explain why it is reasonable to expect that the source's emission rate will not increase in the future.

Thank you,

David Little, PE
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From: David Little
To: Leath, Mark
Cc: Basham, Aaron; Alsharafi, Adel; Daniel Hedrick; Clay Dodson; Kelly Turner; Gerad Fox; Kevin Cline
Subject: RE: CU Regional Haze call follow-up
Date: Friday, December 3, 2021 11:32:00 AM
Attachments: image001.png

Mark,

CU previously claimed a JTEC Unit 1 SO2 control efficiency from using PAC injection. After further review, the exact control efficiency is difficult to justify given slight natural variations in coal quality and sulfur content combined with combustion reactions and flue gas properties. However, we still maintain that PAC injection controls SO2. This is supported by the following journal articles to name a few.

https://www.sciencedirect.com/science/article/abs/pii/S0008622397896121

Study on the mechanism of SO2 removal by activated carbon - ScienceDirect

https://pubs.acs.org/doi/10.1021/acs.iecr.9b04443

In addition, the historic SO2 emission rate was 0.50-0.55 lb/MMBtu prior to installation of the baghouse and PAC injection. After these control upgrades, the SO2 emission rate is in the 0.47-0.50 lb/MMBtu range. This reduction is attributed to the baghouse, low sulfur coal quality, and PAC injection.

Thank you,

David Little, PE
Engineer III - Environmental
City Utilities of Springfield, MO
417.831.8532

From: Leath, Mark <mark.leath@dnr.mo.gov>
Sent: Wednesday, December 1, 2021 1:42 PM
To: David Little <David.Little@cityutilities.net>
Cc: Basham, Aaron <aaron.basham@dnr.mo.gov>; Alsharafi, Adel <adel.alsharafi@dnr.mo.gov>; Daniel Hedrick <Daniel.Hedrick@cityutilities.net>; Clay Dodson <Clay.Dodson@cityutilities.net>; Kelly Turner <Kelly.Turner@cityutilities.net>; Gerad Fox <Gerad.Fox@cityutilities.net>; Kevin Cline <Kevin.Cline@cityutilities.net>
Subject: RE: CU Regional Haze call follow-up

Thanks David,

I appreciate you pointing me to this, very useful and can certainly help bolster our narrative justification. Appreciate, all the coordination, we'll keep in touch.

Mark Leath, P.E.
SIP Unit Chief
Missouri Department of Natural Resources
Air Pollution Control Program
Phone: 573-526-5503
Email: mark.leath@dnr.mo.gov

Promoting, Protecting and Enjoying our Natural Resources. Learn more at www.dnr.mo.gov.

From: David Little <David.Little@cityutilities.net>
Sent: Wednesday, December 1, 2021 12:22 PM
To: Leath, Mark <mark.leath@dnr.mo.gov>
Cc: Basham, Aaron <aaron.basham@dnr.mo.gov>; Alsharafi, Adel <adel.alsharafi@dnr.mo.gov>; Daniel Hedrick <Daniel.Hedrick@cityutilities.net>; Clay Dodson <Clay.Dodson@cityutilities.net>; Kelly Turner <Kelly.Turner@cityutilities.net>; Gerad Fox <Gerad.Fox@cityutilities.net>; Kevin Cline <Kevin.Cline@cityutilities.net>
Subject: CU Regional Haze call follow-up

Mark,

On yesterday's call I mentioned EPA's July memo described a steady-state situation as one in which an emission limit may not be necessary. After re-reading the paragraphs, the language actually goes one step further and details requiring the emission control device itself may not be necessary to make reasonable progress. The Unit 1 SCR and NOx emissions have operated at a controlled-steady state for several years, and CU plans to continue as such. Therefore, the conclusion can be drawn that SIP-required operation of the SCR may not be necessary, let alone setting of an emission limit. Here is the page 9 excerpt for your consideration. We will compile responses to the other items and look forward to submittal by mid-January as discussed.

However, there may be circumstances in which a source's existing measures are not necessary to make reasonable progress. Specifically, if a state can demonstrate that a source will continue to implement its existing measures and will not increase its emission rate, it may not be necessary to require those measures under the regional haze program in order to prevent future emission increases. In this case, a state may reasonably conclude that a source's existing measures are not necessary to make reasonable progress and thus do not need to be included in the SIP. A determination that a source's existing measures are not necessary to make reasonable progress should be supported by a robust technical demonstration. This empirical, weight-of-evidence demonstration should be based on data and information on (1) the source's past implementation of its existing measures and its historical emission rate, (2) the source's projected emissions and emission rate, and (3) any enforceable emissions limits or other requirements related to the source's existing measures.

Information on a source's past performance using its existing measures may help to inform the expected future operation of that source. If either a source's implementation of its existing measures or the emission rate achieved using those measures has not been consistent in the past, it is not reasonable to assume that the source's emission rate will remain consistent and will not increase in the future. To this end, states should include data for a representative historical period demonstrating that the source has consistently implemented its existing measures and has achieved, using those measures, a reasonably consistent emission rate.[23] For most sources, data from the most recent 5 years (if available) is sufficient to make this showing. Information pertinent to a source's implementation of its existing measures going forward is also critical to a state's demonstration. States should provide data and information on the source's projected emission rate (*e.g.*, for 2028), including assumptions and inputs to those projections. States should justify those assumptions and inputs and explain why it is reasonable to expect that the source's emission rate will not increase in the future.

Thank you,

David Little, PE
Engineer III - Environmental
City Utilities of Springfield, MO
417.831.8532

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City Utilities

City Utilities

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From: Leath, Mark
To: Alsharafi, Adel
Subject: FW: John Twitty Fly Ash sales
Date: Tuesday, February 22, 2022 3:43:03 PM

Adel,
Here are the actual revenues from John Twitty's fly ash sales for the past 6 years.
Thank you,
Mark Leath, P.E.
SIP Unit Chief
Missouri Department of Natural Resources
Air Pollution Control Program
Phone: 573-526-5503
Email: mark.leath@dnr.mo.gov
Promoting, Protecting and Enjoying our Natural Resources. Learn more at www.dnr.mo.gov.

From: David Little <David.Little@cityutilities.net>
Sent: Tuesday, February 22, 2022 3:41 PM
To: Leath, Mark <mark.leath@dnr.mo.gov>
Subject: RE: Time for a quick call
Mark,
Here are the Unit 1 fly ash sales in dollars per year actual, rounded.
2021 – 197,000
2020 – 134,500 unplanned outage
2019 – 183,000 low utilization due to market forces
2018 – 277,000
2017 – 198,000
2016 – 254,000
Thanks,
David

From: Leath, Mark <mark.leath@dnr.mo.gov>
Sent: Tuesday, February 22, 2022 3:23 PM
To: David Little <David.Little@cityutilities.net>
Subject: Time for a quick call
Hey David,
Do you have time for a quick call to discuss a question on the supplemental information you sent on Regional Haze?
I'm free for the next hour, or also tomorrow before 10:00 a.m. or between 3:00 – 4:00 p.m.
If none, of these times work, I'm free most of the time on Thursday and Friday.
Let me know when works best for you. I think it should only take about 10-15 minutes for the discussion.
Thank you,
Mark Leath, P.E.
SIP Unit Chief
Missouri Department of Natural Resources
Air Pollution Control Program

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Email: mark.leath@dnr.mo.gov
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C-3 New Madrid Power Plant Four-Factor Analysis

New Madrid Power Plant-Factor Analysis

Introduction

The Regional Haze Rule requires that states develop and implement comprehensive plans to reduce human caused regional haze in designated Class I areas located within the state, and for each Class I area located outside the state which may be impacted by air emissions from Missouri. Hercules-Glades Wilderness Area and Mingo Wilderness Area are the two Class I areas in Missouri. This long term strategy to reduce regional haze is codified in 40 CFR 51.308(f)(2)(i), requiring states to evaluate and verify if controls on emission sources are necessary, with the goal of returning targeted areas to their natural visibility conditions by 2064. Under the current 2017 Regional Haze Rule, the second planning period is being addressed, with it beginning in 2019 and progressing through 2028. The goal of the second planning period is a phased-strategy toward meeting objectives of the 2064 target year. In this strategy, states have an obligation to consult with the relevant federal land managers during the plan development process, which could include the National Park Service, the U.S. Forest Service, the Bureau of Land Management, and others. Section 169A(g) of the Clean Air Act (CAA) requires the state to assess four factors when considering potential control measures: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of any source evaluated. The Missouri Department of Natural Resources' Air Pollution Control Program (Air Program) focused its four factor analysis strategy on stationary point source emissions of nitrogen oxide (NO_x) and sulfur dioxide (SO_2) for the second planning period because these are the principal anthropogenic pollutants influencing Class I visibility in both Missouri and prospective nearby states. The Air Program conducted a screening analysis for point sources by pairing 2016 emissions over distance with combined sulfate and nitrate extinction-weighted residence times (EWRT) meeting a one percent threshold to determine which sources would be evaluated for controls based on the four factor analysis to meet the Regional Haze Rule Reasonable Progress Goals (RPG). If a source was selected for a four factor analysis, further evaluation was necessary to determine potentially available emission reduction measures listed in 40 CFR 51.308(f)(2), taking into consideration the U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*. Additionally, the Air Program used EPA's updated 2028 Regional Haze Modeling to estimate visibility conditions at the end of the second planning period in 2028. According to this modeling, both Missouri Class I areas' 2028 RPGs are below the Uniform Rate of Progress (URP) and hence meet the goals for the regional haze second planning period. Subsequently, Missouri meets the goals for the regional haze second planning period without adjusting the URP to account for impact from anthropogenic sources outside the United Sates, as the regional haze rule for the second planning period includes a provision that allows states to propose an adjustment.

Facility Description

Associated Electric Cooperative Incorporated's New Madrid Power Plant (New Madrid) is located in New Madrid County, Missouri. New Madrid began operations in the early 1970's and currently operates two coal-fired units that combine to generate 1,280 MW. The two coal fired steam generating boilers are the main sources of air pollutants. Unit 1 completed construction in 1972 and Unit 2 began operations in 1977, each having a capacity of 640 MW. Both turbine/generator units are Brown Boveri with cyclone boilers designed by Babcock & Wilcox. The two coal fired units are the focus of this analysis as verified through screening, although there are additional emission sources at the facility.

The two New Madrid facility coal fired units are boilers. Unit 1 is a cycle fired boiler, fires up to 6,728 million British thermal units per hour (mmBtu/hr) of fuels and is designed to burn coal and fuel oil. Unit 2 is also cycle fired boiler, fires up to 6,985 mmBtu/hr of fuels and is designed to burn coal and fuel oil. The following table summarizes the emission controls currently in place for Units 1 and 2:

	Unit 1	Unit 2
SO_2	Powder River Basin low sulfur coal	Powder River Basin low sulfur coal
NO_x	Overfire Air Selective Catalytic Reduction (BACT); control efficiency of 90 percent	Overfire Air Selective Catalytic Reduction (BACT); control efficiency of 90 percent
PM/Mercury	Electrostatic precipitator, cold side, without flue gas conditioning (BACT) and; Powdered activated carbon injection system; control efficiency of 99 percent for PM	Electrostatic precipitator, cold side, without flue gas conditioning (BACT) and; Powdered activated carbon injection system; control efficiency of 99 percent for PM

Baseline SO_2 and NO_x Emissions

The first step in developing this four factor analysis was to determine the baseline SO_2 and NO_x emissions for Unit 1 and Unit 2 respectively. The averaging period from January 1, 2015 through December 31, 2020 was used because it represents the latest complete annual emissions reported for each of these sources. Baseline annual SO_2 and NO_x emissions for these two units were obtained from continuous emission monitoring systems data contained in EPA's Clean Air Markets Division through their Air Markets Program Data.[1] Using baseline annual emissions information for the years 2015, 2016, 2017, 2018, 2019, and 2020, average pounds per hour, and average heat input were established. The following table summarizes the SO_2 and NO_x baseline emissions for New Madrid Units 1 and 2.

[1] U.S. Environmental Protection Agency, Clean Air Markets Division, Air Markets Program Data, 2021.

Facility source	Air Contaminate	Average pounds per hour (lb/hr)	Average tons per year (tpy)	Average million British thermal units per year (mmBtu/year)	Timeframe
Unit 1	SO_2	1,768	6,359	31,930,996	Emissions based on 36-month annual average (1/1/15-12/31/20)
	NO_x	1,973	7,096		
Unit 2	SO_2	1,778	6,732	32,254,214	Emissions based on 36-month annual average (1/1/15-12/31/20)
	NO_x	1,652	6,253		

Sulfur Dioxide Emission Controls

Coal Washing

Coal washing, also known as coal cleaning or coal beneficiation, involves separating out impurities from coal in a liquid medium and can include processes to remove ash, sulfur and moisture. The liquid medium may be combined with finely ground heavier minerals to achieve better separation of unwanted rock and mineral material from coal particles. Washing operations are carried out after coal is sized, then a number of different washing techniques are used depending on coal particle size, the type of coal, and the required level of preparation. The coal is next dewatered with the waste streams discarded. Although typically used for bituminous and anthracitic coals, subbituminous and lignite coals are more difficult to separate out mineral material and coal washing is more infrequent. Therefore, this technology was not further evaluated.

Coal Switching

An option for reducing SO_2 emissions is to reduce the sulfur content of the coal. Reducing the amount of sulfur in the coal inhibits the amount released during the combustion process, and would decrease the amount of SO_2 introduced further in the system. New Madrid burns western subbituminous coal, with an average sulfur content in the range of 0.18 to 0.22.[2] Because of the inherently low sulfur content of the coal used by the facility, fuel switching will not be further evaluated.

Dry Sorbent Injection (DSI)

Dry Sorbent Injection systems involve the injection of a dry sorbent into the flue gas ductwork following the boiler to reduce concentrations of the acid gases SO_2, hydrogen chloride and hydrogen fluoride which are regulated to prevent sulfur emissions. Sulfur oxides typically react directly with the dry sorbent, which are collected in a downstream particulate control device. The injection of hydrated lime, trona, or sodium bicarbonate into the flue gas for the removal of SO_2 and sulfur trioxide is a proven solution to reduce sulfur emissions. DSI is a system that is capable of between 25 to 70 percent SO_2 removal, and higher with a fabric filter. Advantages of this control mechanism include lower capital cost,

[2] U.S. Energy Information Administration, EIA-923; EIA923_Schedules_2_3_4_5_M_12_2019_Final; Page 5 Fuel Receipts and Costs; Fuel Receipts and Cost Time Series File, 2015, 2016, 2017, 2018, 2019, 2020 Final.

less corrosion, and a smaller footprint to those of other technologies. In comparison to other systems, the lower capital costs result in higher operating costs for equivalent SO_2 removal rates.

Unit 1 at the facility is currently burning low sulfur coal and has an activated carbon injection system installed with a mercury removal efficiency listed at 85 percent.[3] DSI's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at New Madrid Unit 1.

Unit 2 at the facility is currently burning low sulfur coal and has an activated carbon injection system installed with a mercury removal efficiency listed at 85 percent.[3] DSI's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at New Madrid Unit 2.

Spray Dryer Absorber (SDA) Flue Gas Desulfurization (FGD)

Spray Dryer Absorber Flue Gas Desulfurization technology operates using absorption as the prevalent collection mechanism. In general, the acid gas dissolves into the alkaline slurry droplets and then reacts with the alkaline material to form a filterable solid. Contact between the alkaline sorbent, usually hydrated lime, and flue gases make the gas removal process effective. The lime slurry is then atomized into droplets within the gas stream. The fine spray provides a high contact area in order for gas absorption to occur. Acid gases are then absorbed onto the atomized droplets. Evaporation of the slurry water in the droplets occurs at the same time as the acid gas absorption. The cooled flue gas then carries the dried reaction product downstream to the fabric filter. This dried reaction product can be recycled to optimize lime use. SDA and FGD systems can have a 70 to 90 percent SO_2 removal efficiency, and in some cases higher.

Unit 1 at the facility is currently burning low sulfur coal and has an activated carbon injection system installed with a mercury removal efficiency listed at 85 percent.[3] Dry FGD's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at New Madrid Unit 1.

Unit 2 at the facility is currently burning low sulfur coal and has an activated carbon injection system installed with a mercury removal efficiency listed at 85 percent.[3] Dry FGD's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at New Madrid Unit 2.

Wet FGD

In a Wet Flue Gas Desulfurization system, flue gas is channeled to a spray tower where a fluid slurry of sorbent is injected into the flue gas. The nozzles and injection locations are designed to optimize the size and density of slurry droplets formed by the system to provide good contact between the waste gas and sorbent. Part of the water in the slurry is evaporated and the waste gas stream becomes saturated.

[3] U.S. Energy Information Administration, EIA-923; EIA923_Schedule_8_Annual_Environmental_Information_2019_Final; 8C Air Emissions Control Info; Annual Environmental Information, Schedule 8. Part C. Air Emissions Control Information, 2015, 2016, 2017, 2018, 2019, 2020 Final.

Sulfur dioxide dissolves into the slurry droplets where it reacts with the alkaline particles. The slurry falls to the bottom of the absorber where it is collected. Treated flue gas passes through a mist eliminator and then exits the absorber to remove any caught slurry droplets. The effluent is sent to a reaction tank where the SO_2/alkali reaction is completed forming a neutral salt. After passing through the tank, systems dewater the used slurry for disposal or use as a byproduct. Most wet scrubbers have removal efficiencies in between 80 to 98 percent.

Unit 1 at the facility is currently burning low sulfur coal and has an activated carbon injection system installed with a mercury removal efficiency listed at 85 percent.[3] Wet FGD's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at New Madrid Unit 1.

Unit 2 at the facility is currently burning low sulfur coal and has an activated carbon injection system installed with a mercury removal efficiency listed at 85 percent.[3] Wet FGD's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at New Madrid Unit 2.

Nitrogen Oxide Emission Controls

Low NO_x burners and Overfire Air

Low NO_x burners are used by many utilities throughout the country for both new and retrofit applications. Low NO_x burners limit NO_x formation by influencing the stoichiometric and temperature profiles of the combustion process in each burner flame. This type of control is accomplished due to machinery designs that stabilize the distribution and mixing of the fuel and air. As a result, O_2 is reduced in the primary combustion zone, there is a reduced flame temperature, and a there is a reduced residence time at peak temperature, all of which limit the formation of NO_x.

Unit 1 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 90 percent and is considered the best available control technology (BACT). The unit also operates an overfire air system with a control efficiency of 20 percent. Low NO_x burners are not a feasible option to be placed on cyclone fired boilers and therefore were not evaluated further.

Unit 2 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 90 percent and is considered BACT. The unit also operates an overfire air system with a control efficiency of 20 percent. Low NO_x burners are not a feasible option to be placed on cyclone fired boilers and therefore were not evaluated further.

Selective NonCatalytic Reduction (SNCR)

A Selective NonCatalytic Reduction system converts NO_x into nitrogen and water by injecting reagents at high temperature without the need of a catalyst. The system can achieve high reduction rates without the use of additional catalyst if the process is set at the correct temperature range. In this system, the ammonia or urea reagents, are injected directly into the existing flue gas pipe flow using water as a carrier in order to cover the entire cross section in the correct temperature range. This system can be an economical form of NO_x reducing technology and works for applications where a modest NO_x reduction of about 30 to 40 percent is required along with tight schedules where the flue gas temperatures are high enough (895°C-1100°C) to promote the reactions. SNCR systems can reduce NO_x emission in a range from 30 to 60 percent.

Unit 1 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 90 percent and is considered the best available control technology (BACT). The unit also operates an overfire air system with a control efficiency of 20 percent. Because this unit currently has a selective catalytic reduction system, a SNCR was not further evaluated.

Unit 2 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 90 percent and is considered BACT. The unit also operates an overfire air system with a control efficiency of 20 percent. Because this unit currently has a selective catalytic reduction system, a SNCR was not further evaluated.

Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction technology is a proven and effective method to reduce NO_x emissions from coal fired power plants. In general, all through the combustion process, the nitrogen that occurs naturally in the coal, and the nitrogen and oxygen existing in the combustion air, combine to form NO_x. Before being released to the atmosphere, the exhaust gas proceeds through a large catalyst where the NO_x reacts with the catalyst and ammonia and is converted to nitrogen and water. Selective catalytic reduction typically removes between 75 to 85 percent, and higher, of the NO_x that is in the exhaust gas of a coal-fired power plant.

Unit 1 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 90 percent and is considered BACT. The unit also operates an overfire air system with a control efficiency of 20 percent. Because the SCR system may not be continuously in operation, the current SCR will be further evaluated based on various percent reductions of NO_x.

Unit 2 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 90 percent and is considered BACT. The unit also operates an overfire air system with a control efficiency of 20 percent. Because the SCR system may not be continuously in operation, the current SCR will be further evaluated based on various percent reductions of NO_x.

The following table summarizes both the technologies that have been eliminated and evaluated for further study as discussed above and the expected control efficiency.

Technology	Evaluated Further	Assumed Control Efficiency (%)
Coal Washing	No	-
Coal Switching	No	-
Dry Sorbent Injection	Yes, Unit 1 Yes, Unit 2	80
Spray Dryer Absorber Flue Gas Desulfurization	Yes, Unit 1 Yes, Unit 2	~90
Wet Flue Gas Desulfurization	Yes, Unit 1 Yes, Unit 2	~95.5

Technology	Evaluated Further	Assumed Control Efficiency (%)
Low NO_x Burners	No, Unit 1 No, Unit 2	-
Selective NonCatalytic Reduction	No, Unit 1 No, Unit 2	-
Selective Catalytic Reduction	Yes, Unit 1 Yes, Unit 2	25, 45, 65, and 85

Four Factor Analysis

Costs of Compliance

Cost assessments for the control technologies evaluated were made utilizing the EPA Air Pollution Control Cost Manual Section 4, NO_x Controls, updated in 2019, and Section 5, SO_2 and Acid Gas Controls, updated in 2021. Estimates were also obtained by completing spreadsheets for SO_2 and NO_x controls using EPA's Control Cost Manual, and for SCR's, EPA's Clean Air Markets Division Retrofit Analyzer tool, last updated in 2019.[4] The complete costs derived from the Cost Manual and the retrofit analyzer tool may be found in the appendices for Unit 1 and Unit 2. The Capital Recovery Factor (CRF) was based on an interest rate of 3.25 percent and the unit's useful life for Unit 1, due to 2028 being the next Regional Haze reduction phase. The CRF was based on an interest rate of 3.25 percent and the unit's useful life for Unit 2. A typical overall lifespan for an electric generating unit of 55 years was used, however there is no enforceable shutdown date codified.[5] Cost estimates derived from the spreadsheet were converted to 2019 dollars for all control technology equipment. A summary of the control technologies further evaluated with costs and effectiveness is contained in the following tables. The below table shows the estimated cost of control for each selected control technologies and remaining useful life scenario as discussed in the main SIP document. The last column shows that the cost effectiveness of all control technologies exceed the cost effectiveness threshold of $3,658 per ton removed.

For DSI, the Air Program assumed that the facility will utilize milled Trona along with the existing electrostatic precipitator (ESP). It is likely that the existing ESP will not be able to handle the increase of particulate matter emissions associated with using the Trona; therefore, the facility needs to either upgrade the ESP or install a baghouse. The Air Program did not take into consideration the cost of upgrading the ESP or installing a baghouse in this cost analysis. Finally, the Air Program used 2021 CEPCI to project to control cost from 2016.

NO_x and SO_2 Control Costs and Effectiveness

Control Equipment	Boiler	Control Efficiency (%)	Remaining Useful Life (year)	Capital Costs	Annualized Costs	Emission removal (ton)	Cost Effectiveness (2021$/removed ton)
Wet FGD	Unit 1	95.5	8.0	$350,713,847	$62,304,249	5,999	$10,386
	Unit 2		8.0	$347,354,244	$62,106,097	6,639	$9,355

[4] U.S. Environmental Protection Agency, Clean Air Markets Division, Retrofit Cost Analyzer, 2019.
[5] U.S. Energy Information Administration, EIA-860; 3_1_Generator_Y2019; Retired and Canceled; 2015, 2016, 2017, 2018, 2019 Form EIA-860 Data - Schedule 3, 'Generator Data' (Retired & Canceled Units Only).

Control Equipment	Boiler	Control Efficiency (%)	Remaining Useful Life (year)	Capital Costs	Annualized Costs	Emission removal (ton)	Cost Effectiveness (2021$/removed ton)
SDA	Unit 1	90	8.0	$333,524,947	$59,408,795	5,653	$10,509
	Unit 2		8.0	$333,524,947	$59,785,890	6,257	$9,556
DSI with EPS	Unit 1	80	8.0	$25,905,841	$22,549,837	5,025	$4,487
	Unit 2		9.5	$26,052,366	$23,786,787	5,561	$4,277
Wet FGD*	Unit 1	95.5	25	$350,713,847	$32,493,572	5,999	$5,417
	Unit 2		25	$347,354,244	$32,580,987	6,639	$4,908
SDA*	Unit 1	90	25	$333,524,947	$31,059,174	5,653	$5,494
	Unit 2		25	$333,524,947	$31,436,269	6,257	$5,025
DSI with EPS*	Unit 1	80	25	$25,905,841	$20,349,828	5,025	$4,050
	Unit 2		25	$26,052,366	$22,093,465	5,561	$3,973

SCR at Various Efficiencies Cost Effectiveness

Control Equipment	Boiler	Capital Costs	Annual Operating and Maintenance Costs	Annualized Costs	Emission removal (ton)	Cost Effectiveness (2021$/removed ton)
SCR (85%)	Unit 1	---	$14,147,417	---	14,376	$984
	Unit 2	---	$12,773,598	---	12,876	$992
SCR (65%)	Unit 1	---	$11,429,009	---	10,994	$1,040
	Unit 2	---	$10,298,774	---	9,846	$1,046
SCR (45%)	Unit 1	---	$8,615,950	---	7,611	$1,132
	Unit 2	---	$7,832,302	---	6,816	$1,149
SCR (25%)	Unit 1	---	$5,793,147	---	4,228	$1,370
	Unit 2	---	$5,264,220	---	3,787	$1,390

Time Necessary for Compliance

The time necessary for compliance is the period needed for full implementation of the evaluated feasible control options. This would include the time needed to develop and finalize the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. Estimates for compliance ranged from 18 months for coal washing, 30 months for Dry Sorbent Injection, and 52 months each for Spray Dryer Absorber Flue Gas Desulfurization, and Wet Flue Gas Desulfurization, and 42 months for Selective Catalytic Reduction.

Energy Impacts

Dry Sorbent Injection: DSI systems would require auxiliary power at the plant by use of electricity to operate fans, pumps, and other equipment. Additional fuel would be expended at the facility to produce this electricity. Additionally, there would be a heat rate penalty associated with this technology.

Spray Dryer Absorber Flue Gas Desulfurization: Lime used in dry FGD systems must be hydrated prior to use, increasing the facility’s overall consumption of electricity.

Wet Flue Gas Desulfurization: The primary energy impacts of the wet FGD alternative consists of the additional electrical load resulting from pumps and reagent preparation. As a result, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output.

Selective Catalytic Reduction: SCR systems would require additional electricity to operate fans, pumps, and other equipment. If the electricity were generated on site, additional fuel would be used by the source to produce this electricity, or it would need to would come from the electric grid. If the additional electricity came from the plant, the boiler heat input would have to increase to compensate for the increased auxiliary power usage.

Non-Air Quality Environmental Impacts of Compliance

Dry Sorbent Injection: This technology would require additional precautions for fuel handling and waste systems to prevent non-air environmental impacts due to increased effluents in wastewater discharges and storm water runoff.

Spray Dryer Absorber Flue Gas Desulfurization: Using this control technology would require the facility to handle limestone for injection in the unit, and pebble lime for use in the dry scrubber. The lime used in this technology would need to be hydrated prior to use, raising the facility's overall water usage. If polluted water is released from the facility, wastewater treatment may be necessary.

Wet Flue Gas Desulfurization: This technology would increase calcium sulfate solids disposal. Typically solid wastes generated using this technology are dewatered and disposed of in landfills. Some of these control systems may be able to generate a gypsum byproduct that can be sold in the open market. If the gypsum cannot be sold, proper disposal would then be required. Significant water use for this technology may require treatment before being discharged in order to meet water effluent limits.

Selective Catalytic Reduction: The operation of an SCR system could have non-air environmental impacts due to the storage of ammonia at the facility. This may cause the potential for accidents due to an ammonia release. Post-control NO_x systems such as SCR would require additional safeguards for proper handling of reducing reagents such as urea or ammonia. Depending on the ammonia type, concentration, and quantity used, the material may also be subject to regulations such as the hazardous substances under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), and Clean Water Act.

Summary

Based on a review of possible and feasible options to reduce SO_2 and NO_x emissions at Unit 1, and Unit 2, the Air Program has determined that there are no cost-effective methods of SO_2 and NO_x reduction for this facility. All Class I areas impacted by sources in Missouri have made steady and significant improvement in visibility, and modeling shows they are projected to be below, or well below, their uniform rate of progress (URP) glidepaths in 2028. In conclusion, on the completion of the four factor analysis in this report, the Air Program is proposing to maintain current operational practices consistent with the parameters and limits in the New Madrid Power Plant Air Pollution Control Title V Permit to Operate.

**All control cost estimate calculations for wet FGD, SDA, DSI and SCR for both remaining useful life (RUL) scenarios are provided in the attached spreadsheets

New Madrid Unit 1 NOx SCR-EPA-RUL.xlsx
New Madrid Unit 1 NOx SCR-Original-RUL.xlsx
New Madrid Unit 1 SO2 DSI-EPA-RUL.xlsx
New Madrid Unit 1 SO2 DSI-Original-RUL.xlsx
New Madrid Unit 1 SO2 SDA-EPA-RUL.xlsm
New Madrid Unit 1 SO2 SDA-Original-RUL.xlsm
New Madrid Unit 1 SO2 wet_FGD-EPA-RUL.xlsm
New Madrid Unit 1 SO2 wet_FGD-Original-RUL.xlsm
New Madrid Unit 2 NOx SCR-EPA-RUL.xlsx
New Madrid Unit 2 NOx SCR-Original-RUL.xlsx
New Madrid Unit 2 SO2 DSI-EPA-RUL.xlsx
New Madrid Unit 2 SO2 DSI-Original-RUL.xlsx
New Madrid Unit 2 SO2 SDA-EPA-RUL.xlsm
New Madrid Unit 2 SO2 SDA-Original-RUL.xlsm
New Madrid Unit 2 SO2 wet_FGD-EPA-RUL.xlsm
New Madrid Unit 2 SO2 wet_FGD-Original-RUL.xlsm

C-4 Thomas Hill Energy Center Four-Factor Analysis

Thomas Hill Energy Center Four-Factor Analysis

Introduction

The Regional Haze Rule requires that states develop and implement comprehensive plans to reduce human caused regional haze in designated Class I areas located within the state, and for each Class I area located outside the state which may be impacted by air emissions from Missouri. Hercules-Glades Wilderness Area and Mingo Wilderness Area are the two Class I areas in Missouri. This long term strategy to reduce regional haze is codified in 40 CFR 51.308(f)(2)(i), requiring states to evaluate and verify if controls on emission sources are necessary, with the goal of returning targeted areas to their natural visibility conditions by 2064. Under the current 2017 Regional Haze Rule, the second planning period is being addressed, with it beginning in 2019 and progressing through 2028. The goal of the second planning period is a phased-strategy toward meeting objectives of the 2064 target year. In this strategy, states have an obligation to consult with the relevant federal land managers during the plan development process, which could include the National Park Service, the U.S. Forest Service, the Bureau of Land Management, and others. Section 169A(g) of the Clean Air Act (CAA) requires the state to assess four factors when considering potential control measures: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of any source evaluated. The Missouri Department of Natural Resources' Air Pollution Control Program (Air Program) focused its four factor analysis strategy on stationary point source emissions of nitrogen oxide (NO_x) and sulfur dioxide (SO_2) for the second planning period because these are the principal anthropogenic pollutants influencing Class I visibility in both Missouri and prospective nearby states. The Air Program conducted a screening analysis for point sources by pairing 2016 emissions over distance with combined sulfate and nitrate extinction-weighted residence times (EWRT) meeting a one percent threshold to determine which sources would be evaluated for controls based on the four factor analysis to meet the Regional Haze Rule Reasonable Progress Goals (RPG). If a source was selected for a four factor analysis, further evaluation was necessary to determine potentially available emission reduction measures listed in 40 CFR 51.308(f)(2), taking into consideration the U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*. Additionally, the Air Program used EPA's updated 2028 Regional Haze Modeling to estimate visibility conditions at the end of the second planning period in 2028. According to this modeling, both Missouri Class I areas' 2028 RPGs are below the Uniform Rate of Progress (URP) and hence meet the goals for the regional haze second planning period. Subsequently, Missouri meets the goals for the regional haze second planning period without adjusting the URP to account for impact from anthropogenic sources outside the United Sates, as the regional haze rule for the second planning period includes a provision that allows states to propose an adjustment.

Facility Description

Thomas Hill Energy Center (Thomas Hill) is a coal-fired power plant located in the town of Clifton Hill, in Randolph County, Missouri which converts the energy from coal and other fuels to electrical energy. The main sources of emissions are boilers that primarily combust coal and secondarily combust fuel oil. The power plant consists of three units that have a combined generating capacity of about 1,267 megawatts (MW). Unit one is a General Electric turbine with a net capacity of 185 MW, Unit 2 is a Westinghouse turbine with a net capacity of 305 MW, and Unit 3 is a Westinghouse turbine with a net capacity of 777

MW. When operating at full net capacity, the combined coal burn rate of all three units is approximately 14,461 tons per day. The Thomas Hill Energy Center is owned and operated by Associated Electric Cooperative, Inc. The three coal fired units are the focus of this analysis as verified through screening, although there are additional emission sources at the facility.

The three Thomas Hill facility coal fired units are all boilers. Unit 1 is a cycle fired boiler which was installed in 1966, fires up to 2,250 million British thermal units per hour (mmBtu/hr) of fuels and is designed to burn coal and fuel oil. Unit 2 is a cycle fired boiler which was installed in 1969, fires up to 3,579 mmBtu/hr of fuels and is designed to burn coal and fuel oil. Unit 3 is a wall fired boiler which was installed in 1982, fires up to 9,003 mmBtu/hr of fuels and is designed to burn coal and fuel oil. The following table summarizes the emission controls currently in place for Units 1, 2, and 3:

	Unit 1	Unit 2	Unit 3
SO_2	Powder River Basin low sulfur coal	Powder River Basin low sulfur coal	Powder River Basin low sulfur coal
NO_x	Overfire Air Selective Catalytic Reduction (BACT); control efficiency of 90 percent	Overfire Air Selective Catalytic Reduction (BACT); control efficiency of 90 percent	Overfire Air Selective Catalytic Reduction (BACT); control efficiency of 90 percent
PM/Mercury	Electrostatic precipitator, cold side, without flue gas conditioning (BACT) and powdered activated carbon injection system; control efficiency of 99 percent for PM	Electrostatic precipitator, cold side, without flue gas conditioning (BACT) and powdered activated carbon injection system; control efficiency of 99 percent for PM	Electrostatic precipitator, cold side, without flue gas conditioning (BACT) and powdered activated carbon injection system; control efficiency of 99 percent for PM

Baseline SO_2 and NO_x Emissions

The first step in developing this four factor analysis was to determine the baseline SO_2 and NO_x emissions for Unit 1, Unit 2, and Unit 3 respectively. The averaging period from January 1, 2015 through December 31, 2020 was used because it represents the latest complete annual emissions reported for each of these sources. Baseline annual SO_2 and NO_x emissions for these three units were obtained from continuous emission monitoring systems data contained in EPA's Clean Air Markets Division through their Air Markets Program Data.[1] Using baseline annual emissions information for the years 2015, 2016,

[1] U.S. Environmental Protection Agency, Clean Air Markets Division, Air Markets Program Data, 2021.

2017, 2018, 2019, and 2020, average pounds per hour, and average heat input were established. The following table summarizes the SO_2 and NO_x baseline emissions for Thomas Hill Units 1, 2, and 3.

Facility source	Air Contaminate	Average pounds per hour (lb/hr)	Average tons per year (tpy)	Average million British thermal units per year (mmBtu/year)	Timeframe
Unit 1	SO_2	628	2,290	11,887,239	Emissions based on 36-month annual average (1/1/15-12/31/20)
	NO_x	646	2,355		
Unit 2	SO_2	969	3,531	18,639,238	Emissions based on 36-month annual average (1/1/15-12/31/20)
	NO_x	1,068	3,890		
Unit 3	SO_2	2,558	9,719	47,387,294	Emissions based on 36-month annual average (1/1/15-12/31/20)
	NO_x	1,188	4,515		

Sulfur Dioxide Emission Controls

Coal Washing

Coal washing, also known as coal cleaning or coal beneficiation, involves separating out impurities from coal in a liquid medium and can include processes to remove ash, sulfur and moisture. The liquid medium may be combined with finely ground heavier minerals to achieve better separation of unwanted rock and mineral material from coal particles. Washing operations are carried out after coal is sized, then a number of different washing techniques are used depending on coal particle size, the type of coal, and the required level of preparation. The coal is next dewatered with the waste streams discarded. Although typically used for bituminous and anthracitic coals, subbituminous and lignite coals are more difficult to separate out mineral material and coal washing is more infrequent. Therefore, this technology was not further evaluated.

Coal Switching

An option for reducing SO_2 emissions is to reduce the sulfur content of the coal. Reducing the amount of sulfur in the coal inhibits the amount released during the combustion process, and would decrease the amount of SO_2 introduced further into the system. Thomas Hill burns western subbituminous coal, with an average sulfur content in the range of 0.18 to 0.22.[2] Because of the inherently low sulfur content of the coal used by the facility, fuel switching will not be further evaluated.

Dry Sorbent Injection (DSI)

[2] U.S. Energy Information Administration, EIA-923; EIA923_Schedules_2_3_4_5_M_12_2019_Final; Page 5 Fuel Receipts and Costs; Fuel Receipts and Cost Time Series File, 2015, 2016, 2017, 2018, 2019, 2020 Final.

Dry Sorbent Injection systems involve the injection of a dry sorbent into the flue gas ductwork following the boiler to reduce concentrations of the acid gases SO_2, hydrogen chloride and hydrogen fluoride which are regulated to prevent sulfur emissions. Sulfur oxides typically react directly with the dry sorbent, which are collected in a downstream particulate control device. The injection of hydrated lime, trona, or sodium bicarbonate into the flue gas for the removal of SO_2 and sulfur trioxide is a proven solution to reduce sulfur emissions. DSI is a system that is capable of 25 to 70 percent SO_2 removal, and higher with a fabric filter. Advantages of this control mechanism include lower capital cost, less corrosion, and a smaller footprint to those of other technologies. In comparison to other systems, the lower capital costs result in higher operating costs for equivalent SO_2 removal rates.

Unit 1 at the facility is currently burning low sulfur coal and has an activated carbon injection system installed with a mercury removal efficiency listed at 86 percent.[3] DSI's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at Thomas Hill Unit 1.

Unit 2 at the facility is currently burning low sulfur coal and has an activated carbon injection system installed with a mercury removal efficiency listed at 84 percent.[3] DSI's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at Thomas Hill Unit 2.

Unit 3 at the facility is currently burning low sulfur coal and has an activated carbon injection system installed with a mercury removal efficiency listed at 89 percent.[3] DSI's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at Thomas Hill Unit 3.

Spray Dryer Absorber (SDA) Flue Gas Desulfurization (FGD)

Spray Dryer Absorber Flue Gas Desulfurization technology operates using absorption as the prevalent collection mechanism. In general, the acid gas dissolves into the alkaline slurry droplets and then reacts with the alkaline material to form a filterable solid. Contact between the alkaline sorbent, usually hydrated lime, and flue gases make the gas removal process effective. The lime slurry is then atomized into droplets within the gas stream. The fine spray provides a high contact area in order for gas absorption to occur. Acid gases are then absorbed onto the atomized droplets. Evaporation of the slurry water in the droplets occurs at the same time as the acid gas absorption. The cooled flue gas then carries the dried reaction product downstream to the fabric filter. This dried reaction product can be recycled to optimize lime use. SDA FGD systems can have 70 to 90 percent SO_2 removal efficiency and higher.

Unit 1 at the facility is currently burning low sulfur coal and has an activated carbon injection system installed with a mercury removal efficiency listed at 86 percent.[3] Dry FGD's have been successfully

[3] U.S. Energy Information Administration, EIA-923; EIA923_Schedule_8_Annual_Environmental_Information_2019_Final; 8C Air Emissions Control Info; Annual Environmental Information, Schedule 8. Part C. Air Emissions Control Information, 2015, 216, 2017, 2018, 2019, 2020 Final.

installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at Thomas Hill Unit 1.

Unit 2 at the facility is currently burning low sulfur coal and has an activated carbon injection system installed with a mercury removal efficiency listed at 84 percent.[3] Dry FGD's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at Thomas Hill Unit 2.

Unit 3 at the facility is currently burning low sulfur coal and has an activated carbon injection system installed with a mercury removal efficiency listed at 89 percent.[3] Additionally, this unit currently has in place a spray type wet scrubber that uses limestone/dolomitic limestone/calcium carbonate as a sorbent. The sulfur removal efficiency is listed at 83 percent.[4] However, the wet scrubber at the facility is currently mothballed. Dry FGD's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at Thomas Hill Unit 3.

Wet FGD

In a Wet Flue Gas Desulfurization system, flue gas is channeled to a spray tower where a fluid slurry of sorbent is injected into the flue gas. The nozzles and injection locations are designed to optimize the size and density of slurry droplets formed by the system to provide good contact between the waste gas and sorbent. Part of the water in the slurry is evaporated and the waste gas stream becomes saturated. Sulfur dioxide dissolves into the slurry droplets where it reacts with the alkaline particles. The slurry falls to the bottom of the absorber where it is collected. Treated flue gas passes through a mist eliminator and then exits the absorber to remove any caught slurry droplets. The effluent is sent to a reaction tank where the SO_2/alkali reaction is completed forming a neutral salt. After passing through the tank, systems dewater the used slurry for disposal or use as a byproduct. Most wet scrubbers have removal efficiencies between 80 to 98 percent.

Unit 1 at the facility is currently burning low sulfur coal and has an activated carbon injection system installed with a mercury removal efficiency listed at 86 percent.[3] Wet FGD's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at Thomas Hill Unit 1.

Unit 2 at the facility is currently burning low sulfur coal and has an activated carbon injection system installed with a mercury removal efficiency listed at 84 percent.[3] Wet FGD's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at Thomas Hill Unit 2.

Unit 3 at the facility is currently burning low sulfur coal and has an activated carbon injection system installed with a mercury removal efficiency listed at 89 percent.[3] Additionally, this unit currently has in place a spray type wet scrubber that uses limestone/dolomitic limestone/calcium carbonate as a sorbent. The sulfur removal efficiency is listed at 83 percent.[4] However, the wet scrubber at the facility is currently mothballed. Information was not available to determine how much, if possible, to restart the

[4] U.S. Energy Information Administration, EIA-860; 6_2_EnviroEquip_Y2019; FGD; 2015, 2016, 2017, 2018, 2019, 2020 Form EIA-860 Data - Schedule 6F, 'FGD Data (Including DSI)'.

in place wet scrubber. New Wet FGD's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at Thomas Hill Unit 3.

Nitrogen Oxide Emission Controls

Low NO_x burners and Overfire Air

Low NO_x burners are used by many utilities throughout the country for both new and retrofit applications. Low NO_x burners limit NO_x formation by influencing the stoichiometric and temperature profiles of the combustion process in each burner flame. This type of control is accomplished due to machinery designs that stabilize the distribution and mixing of the fuel and air. As a result, O_2 is reduced in the primary combustion zone, there is a reduced flame temperature, and a there is a reduced residence time at peak temperature, all of which limit the formation of NO_x.

Unit 1 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 90 percent and is considered the best available control technology (BACT). The unit also operates an overfire air system with a control efficiency of 20 percent. Low NO_x burners are not a feasible option to be placed on cyclone fired boilers and therefore were not evaluated further.

Unit 2 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 90 percent and is considered BACT. The unit also operates an overfire air system with a control efficiency of 20 percent. Low NO_x burners are not a feasible option to be placed on cyclone fired boilers and therefore were not evaluated further.

Unit 3 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 90 percent and is considered BACT. The unit also operates an overfire air system with a control efficiency of 20 percent. Because this unit currently has a selective catalytic reduction system, Low NO_x Burners were not further evaluated.

Selective NonCatalytic Reduction (SNCR)

A Selective NonCatalytic Reduction system converts NO_x into nitrogen and water by injecting reagents at high temperature without the need of a catalyst. The system can achieve high reduction rates without the use of additional catalyst if the process is set at the correct temperature range. In this system, the ammonia or urea reagents, are injected directly into the existing flue gas pipe flow using water as a carrier in order to cover the entire cross section in the correct temperature range. This system can be an economical form of NO_x reducing technology and works for applications where a modest NO_x reduction of about 30 to 40 percent is required along with tight schedules where the flue gas temperatures are high enough (895°C-1100°C) to promote the reactions. SNCR systems typically reduce NO_x emission in a range from 30 to 60 percent.

Unit 1 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 90 percent and is considered the best available control technology (BACT). The unit also operates an overfire air system with a control efficiency of 20 percent. Because this unit currently has a selective catalytic reduction system, a SNCR was not further evaluated.

Unit 2 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 90 percent and is considered BACT. The unit also operates an overfire air system with a control efficiency of 20 percent. Because this unit currently has a selective catalytic reduction system, a SNCR was not further evaluated.

Unit 3 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 90 percent and is considered BACT. The unit also operates an overfire air system with a control efficiency of 20 percent. Because this unit currently has a selective catalytic reduction system, a SNCR was not further evaluated.

Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction technology is a proven and effective method to reduce NO_x emissions from coal fired power plants. In general, all through the combustion process, the nitrogen that occurs naturally in the coal, and the nitrogen and oxygen existing in the combustion air, combine to form NO_x. Before being released to the atmosphere, the exhaust gas proceeds through a large catalyst where the NO_x reacts with the catalyst and ammonia and is converted to nitrogen and water. Selective catalytic reduction typically removes between 75 to 85 percent, and in some cases higher, of the NO_x that is in the exhaust gas of a coal-fired power plant.

Unit 1 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 90 percent and is considered BACT. The unit also operates an overfire air system with a control efficiency of 20 percent. Because the SCR system may not be continuously in operation, the current SCR will be further evaluated based on various percent reductions of NO_x.

Unit 2 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 90 percent and is considered BACT. The unit also operates an overfire air system with a control efficiency of 20 percent. Because the SCR system may not be continuously in operation, the current SCR will be further evaluated based on various percent reductions of NO_x.

Unit 3 at the facility is currently operating a selective catalytic reduction system with a control efficiency of 90 percent and is considered BACT. The unit also operates an overfire air system with a control efficiency of 20 percent. Because the SCR system may not be continuously in operation, the current SCR will be further evaluated based on various percent reductions of NO_x.

The following table summarizes both the technologies that have been eliminated and evaluated for further study as discussed above and the expected control efficiency.

Technology	Evaluated Further	Assumed Control Efficiency (%)
Coal Washing	No	-
Coal Switching	No	-
Dry Sorbent Injection	Yes, Unit 1 Yes, Unit 2 Yes, Unit 3	80
Spray Dryer Absorber Flue Gas Desulfurization	Yes, Unit 1 Yes, Unit 2 Yes, Unit 3	~90

Technology	Evaluated Further	Assumed Control Efficiency (%)
Wet Flue Gas Desulfurization (Existing)	No, Unit 3	-
Wet Flue Gas Desulfurization (New)	Yes, Unit 1 Yes, Unit 2 Yes, Unit 3	~95.5
Low NO_x Burners	No, Unit 1 No, Unit 2 No, Unit 3	-
Selective NonCatalytic Reduction	No, Unit 1 No, Unit 2 No, Unit 3	-
Selective Catalytic Reduction	Yes, Unit 1 Yes, Unit 2 Yes, Unit 3	25, 45, 65, and 85

Four Factor Analysis

Costs of Compliance

Cost assessments for the control technologies evaluated were made utilizing the EPA Air Pollution Control Cost Manual Section 4, NO_x Controls, updated in 2019, and Section 5, SO_2 and Acid Gas Controls, updated in 2021. Estimates were also obtained by completing spreadsheets for SO_2 using EPA's Control Cost Manual, and SCR NO_x controls from EPA's Clean Air Markets Division Retrofit Analyzer tool, last updated in 2019.[5] The complete costs derived from the Cost Manual and retrofit analyzer tool may be found in the appendices for Unit 1, Unit 2, and Unit 3. The Capital Recovery Factor (CRF) was based on an interest rate of 3.25 percent and the unit's useful life, due to 2028 being the next Regional Haze reduction phase. The CRF was based on an interest rate of 3.25 percent and the unit's useful life for Unit 3. A typical overall lifespan for an electric generating unit of 55 years was used, however there is no enforceable shutdown date codified.[6] Cost estimates derived from the spreadsheet were converted to 2021 dollars for all control technology equipment. A summary of the control technologies further evaluated with costs and effectiveness is contained in the following tables. The below table shows the estimated cost of control for each selected control technologies and remaining useful life scenario as discussed in the main SIP document. The last column shows that the cost effectiveness of all control technologies exceed the cost effectiveness threshold of $3,658 per ton removed.

For DSI, the Air Program assumed that the facility will utilize milled Trona along with the existing electrostatic precipitator (ESP). It is likely that the existing ESP will not be able to handle the increase of particulate matter emissions associated with using the Trona; therefore, the facility needs to either upgrade the ESP or install a baghouse. The Air Program did not take into consideration the cost of upgrading the ESP or installing a baghouse in this cost analysis. Finally, the Air Program used 2021 CEPCI to project to control cost from 2016.

[5] U.S. Environmental Protection Agency, Clean Air Markets Division, Retrofit Cost Analyzer, 2019.
[6] U.S. Energy Information Administration, EIA-860; 3_1_Generator_Y2019; Retired and Canceled; 2015, 2016, 2017, 2018, 2019 Form EIA-860 Data - Schedule 3, 'Generator Data' (Retired & Canceled Units Only).

NO_x and SO_2 Control Costs and Effectiveness

Control Equipment	Boiler	Control Efficiency (%)	Remaining Useful Life (year)	Capital Costs	Annualized Costs	Emission removal (ton)	Cost Effectiveness (2021$/removed ton)
Wet FGD	Unit 1	95.5	8.0	$170,714,341	$30,787,736	2,193	$14,041
	Unit 2		8.0	$229,769,203	$41,207,077	3,422	$12,041
	Unit 3		12.67	$415,997,255	$55,701,065	9,190	$6,061
SDA	Unit 1	90	8.0	$147,690,824	$26,520,627	2,066	$12,834
	Unit 2		8.0	$205,093,957	$36,806,220	3,225	$11,412
	Unit 3		12.67	$413,827,101	$55,592,054	8,660	$6,419
DSI with ESP	Unit 1	80	8.0	$19,039,330	$9,901,781	1,837	$5,391
	Unit 2		8.0	$21,436,164	$14,112,472	2,867	$4,923
	Unit 3		14.5	$27,882,171	$30,856,224	7,698	$4,008
Wet FGD*	Unit 1	95.5	25	$170,714,341	$16,277,017	2,193	$7,423
	Unit 2		25	$229,769,203	$21,676,695	3,422	$6,334
	Unit 3		25	$415,997,255	$39,685,171	9,190	$4,318
SDA*	Unit 1	90	25	$147,690,824	$13,997,657	2,176	$6,431
	Unit 2		25	$205,093,957	$19,420,347	3,394	$5,722
	Unit 3		25	$413,827,101	$39,797,768	9,154	$4,348
DSI with ESP*	Unit 1	80	25	$19,039,330	$8,284,898	1,837	$4,510
	Unit 2		25	$21,436,164	$12,292,042	2,867	$4,288
	Unit 3		25	$27,882,171	$30,060,400	7,698	$3,905

***** Cost estimates based on remaining useful life based on EPA's control cost manuals

SCR at Various Efficiencies Cost Effectiveness

Control Equipment	Boiler	Capital Costs	Annual Operating and Maintenance Costs	Annualized Costs	Emission removal (ton)	Cost Effectiveness (2021$/removed ton)
SCR (85%)	Unit 1	---	$3,831,940	---	3,512	$1,091
	Unit 2	---	$6,231,601	---	5,849	$1,065
	Unit 3	---	$8,216,470	---	4,126	$1,991
SCR (65%)	Unit 1	---	$3,129,023	---	2,686	$1,165
	Unit 2	---	$5,069,352	---	4,473	$1,133
	Unit 3	---	$7,043,087	---	3,155	$2,232
SCR (45%)	Unit 1	---	$2,430,282	---	1,860	$1,307
	Unit 2	---	$3,911,279	---	3,097	$1,263
	Unit 3	---	$5,820,986	---	2,184	$2,665
SCR (25%)	Unit 1	---	$1,692,568	---	1,033	$1,638
	Unit 2	---	$2,697,530	---	1,720	$1,568
	Unit 3	---	$4,520,938	---	1,214	$3,725

Time Necessary for Compliance

The time necessary for compliance is the period needed for full implementation of the evaluated feasible control options. This would include the time needed to develop and finalize the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. Estimates for compliance ranged from 30 months for Dry Sorbent Injection, and 52 months each for Spray Dryer Absorber Flue Gas Desulfurization, and Wet Flue Gas Desulfurization, and 42 months for Selective Catalytic Reduction.

Energy Impacts

Dry Sorbent Injection: DSI systems would require auxiliary power at the plant by use of electricity to operate fans, pumps, and other equipment. Additional fuel would be expended at the facility to produce this electricity. Additionally, there would be a heat rate penalty associated with this technology.

Spray Dryer Absorber Flue Gas Desulfurization: Lime used in dry FGD systems must be hydrated prior to use, increasing the facility's overall consumption of electricity.

Wet Flue Gas Desulfurization: The primary energy impacts of the wet FGD alternative consists of the additional electrical load resulting from pumps and reagent preparation. As a result, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output.

Non-Air Quality Environmental Impacts of Compliance

Dry Sorbent Injection: This technology would require additional precautions for fuel handling and waste systems to prevent non-air environmental impacts due to increased effluents in wastewater discharges and storm water runoff.

Spray Dryer Absorber Flue Gas Desulfurization: Using this control technology would require the facility to handle limestone for injection in the unit, and pebble lime for use in the dry scrubber. The lime used in this technology would need to be hydrated prior to use, raising the facility's overall water usage. If polluted water is released from the facility, wastewater treatment may be necessary.

Wet Flue Gas Desulfurization: This technology would increase calcium sulfate solids disposal. Typically solid wastes generated using this technology are dewatered and disposed of in landfills. Some of these control systems may be able to generate a gypsum byproduct that can be sold in the open market. If the gypsum cannot be sold, proper disposal would then be required. Significant water use for this technology may require treatment before being discharged in order to meet water effluent limits.

Summary

Based on a review of possible and feasible options to reduce SO_2 and NO_x emissions at Unit 1, Unit 2, and Unit 3, the Air Program has determined that there are no cost-effective methods of SO_2 and NO_x reduction for this facility. All Class I areas impacted by sources in Missouri have made steady and significant improvement in visibility, and modeling shows they are projected to be below, or well below, their uniform rate of progress (URP) glidepaths in 2028. The Air Program is proposing to maintain current operational practices consistent with the parameters and limits in the Thomas Hill Energy Center Air Pollution Control Title V Permit to Operate.

**All control cost estimate calculations for wet FGD, SDA, and DSI for both remaining useful life (RUL) scenarios are provided in the attached spreadsheets

Thomas Hill Unit 1 NOx SCR-EPA-RUL.xlsx
Thomas Hill Unit 1 NOx SCR-Original-RUL.xlsx
Thomas Hill Unit 1 SO2 DSI-EPA-RUL.xlsx
Thomas Hill Unit 1 SO2 DSI-Original-RUL.xlsx
Thomas Hill Unit 1 SO2 SDA-EPA-RUL.xlsm
Thomas Hill Unit 1 SO2 SDA-Original-RUL.xlsm
Thomas Hill Unit 1 SO2 wet_FGD-EPA-RUL.xlsm
Thomas Hill Unit 1 SO2 wet_FGD-Original-RUL.xlsm
Thomas Hill Unit 2 NOx SCR-EPA-RUL.xlsx
Thomas Hill Unit 2 NOx SCR-Original-RUL.xlsx
Thomas Hill Unit 2 SO2 DSI-EPA-RUL.xlsx
Thomas Hill Unit 2 SO2 DSI-Original-RUL.xlsx
Thomas Hill Unit 2 SO2 SDA-EPA-RUL.xlsm
Thomas Hill Unit 2 SO2 SDA-Original-RUL.xlsm
Thomas Hill Unit 2 SO2 wet_FGD-EPA-RUL.xlsm
Thomas Hill Unit 2 SO2 wet_FGD-Original-RUL.xlsm
Thomas Hill Unit 3 NOx SCR-EPA-RUL.xlsx
Thomas Hill Unit 3 NOx SCR-Original-RUL.xlsx
Thomas Hill Unit 3 SO2 DSI-EPA-RUL.xlsx
Thomas Hill Unit 3 SO2 DSI-Original-RUL.xlsx
Thomas Hill Unit 3 SO2 SDA-EPA-RUL.xlsm
Thomas Hill Unit 3 SO2 SDA-Original-RUL.xlsm
Thomas Hill Unit 3 SO2 wet_FGD-EPA-RUL.xlsm
Thomas Hill Unit 3 SO2 wet_FGD-Original-RUL.xlsm

C-5 Sikeston Four-Factor Analysis

Sikeston Four-Factor Analysis

Introduction

The Regional Haze Rule requires that states develop and implement comprehensive plans to reduce human caused regional haze in designated Class I areas located within the state, and for each Class I area located outside the state which may be impacted by air emissions from Missouri. Hercules-Glades Wilderness Area and Mingo Wilderness Area are the two Class I areas in Missouri. This long term strategy to reduce regional haze is codified in 40 CFR 51.308(f)(2)(i), requiring states to evaluate and verify if controls on emission sources are necessary, with the goal of returning targeted areas to their natural visibility conditions by 2064. Under the current 2017 Regional Haze Rule, the second planning period is being addressed, with it beginning in 2019 and progressing through 2028. The goal of the second planning period is a phased-strategy toward meeting objectives of the 2064 target year. In this strategy, states have an obligation to consult with the relevant federal land managers during the plan development process, which could include the National Park Service, the U.S. Forest Service, the Bureau of Land Management, and others. Section 169A(g) of the Clean Air Act (CAA) requires the state to assess four factors when considering potential control measures: The cost of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of any source evaluated. The Missouri Department of Natural Resources' Air Pollution Control Program (Air Program) focused its four factor analysis strategy on stationary point source emissions of nitrogen oxide (NO_x) and sulfur dioxide (SO_2) for the second planning period because these are the principal anthropogenic pollutants influencing Class I visibility in both Missouri and prospective nearby states. The Air Program conducted a screening analysis for point sources by pairing 2016 emissions over distance with combined sulfate and nitrate extinction-weighted residence times (EWRT) meeting a one percent threshold to determine which sources would be evaluated for controls based on the four factor analysis to meet the Regional Haze Rule Reasonable Progress Goals (RPG). If a source was selected for a four factor analysis, further evaluation was necessary to determine potentially available emission reduction measures listed in 40 CFR 51.308(f)(2), taking into consideration the U.S. Environmental Protection Agency's (EPA's) *Draft Guidance on Progress Tracking Metrics, Long Term Strategies, Reasonable Progress Goals and Other Requirements for Regional Haze State Implementation Plans for the Second Implementation Period*. Additionally, the Air Program used EPA's updated 2028 Regional Haze Modeling to estimate visibility conditions at the end of the second planning period in 2028. According to this modeling, both Missouri Class I areas' 2028 RPGs are below the Uniform Rate of Progress (URP) and hence meet the goals for the regional haze second planning period. Subsequently, Missouri meets the goals for the regional haze second planning period without adjusting the URP to account for impact from anthropogenic sources outside the United Sates, as the regional haze rule for the second planning period includes a provision that allows states to propose an adjustment.

Facility Description

Sikeston Power Station (Sikeston) is owned and operated by the Sikeston Board of Municipal Utilities, and is located in Scott County, Missouri. The utility serves approximately 8,600 retail customers in the city. Sikeston also sells its wholesale power to the cities of Carthage, Columbia, Fulton, and West Plains, representing about half the capacity of its 235 megawatt steam turbine generator. This utility produces electric power through use of one coal fired unit that has the capability to burn fuel oils No. 2 and petroleum coke. The coal fired unit is the focus of this analysis as verified through screening, although there are additional emission sources at the facility.

The Sikeston facility's pulverized coal fired unit is a Babcock and Wilcox wall fired boiler, operational in 1981, and fires up to 2,349 million British thermal units per hour (mmBtu/hr) of fuels. The following table summarizes the emission controls currently in place for Unit 1:

	Unit 1
SO_2	Powder River Basin low sulfur coal Tray/Venturi type wet scrubber; control efficiency of 76 percent; scrubber is currently not operating
NO_x	Low NO_x burners with overfire air; control efficiency of 55 percent
PM/Mercury	Electrostatic precipitator, cold side, without flue gas conditioning; control efficiency of 99.4 percent, and Powdered activated carbon injection system; control efficiency of 87.3 percent for mercury

Baseline SO_2 and NO_x Emissions
The first step in developing this four factor analysis was to determine the baseline SO_2 and NO_x emissions for Unit 1. The averaging period from January 1, 2015 through December 31, 2020 was used because it represents the latest complete annual emissions reported for each of these sources. Baseline annual SO_2 and NO_x emissions for this unit was obtained from continuous emission monitoring systems data contained in EPA's Clean Air Markets Division through their Air Markets Program Data.[1] Using baseline annual emissions information for the years 2015, 2016, 2017, 2018, 2019, and 2020, average pounds per hour, and average heat input were established. The following table summarizes the SO_2 and NO_x baseline emissions for Sikeston Unit 1.

Facility source	Air Contaminate	Average pounds per hour (lb/hr)	Average tons per year (tpy)	Average million British thermal units per year (mmBtu/year)	Timeframe
Unit 1	SO_2	1,120	4,386	16,589,913	Emissions based on 36-month annual average (1/1/15-12/31/20)
	NO_x	230	901		

[1] U.S. Environmental Protection Agency, Clean Air Markets Division, Air Markets Program Data, 2021.

Sulfur Dioxide Emission Controls

Coal Washing

Coal washing, also known as coal cleaning or coal beneficiation, involves separating out impurities from coal in a liquid medium and can include processes to remove ash, sulfur and moisture. The liquid medium may be combined with finely ground heavier minerals to achieve better separation of unwanted rock and mineral material from coal particles. Washing operations are carried out after coal is sized, then a number of different washing techniques are used depending on coal particle size, the type of coal, and the required level of preparation. The coal is next dewatered with the waste streams discarded. Although typically used for bituminous and anthracitic coals, subbituminous and lignite coals are more difficult to separate out mineral material and coal washing is more infrequent. Therefore, this technology was not further evaluated.

Coal Switching

An option for reducing SO_2 emissions is to reduce the sulfur content of the coal. Reducing the amount of sulfur in the coal inhibits the amount released during the combustion process, and would decrease the amount of SO_2 introduced further in the system. Burning low sulfur coal also helps optimize mercury removal with the facility's Active Carbon Injection system. Sikeston burns western subbituminous coal, with an average sulfur content in the range of 0.23 to 0.68.[2] Because of the inherently low sulfur content of the coal used by the facility, and its dual benefit of mercury removal, fuel switching will not be further evaluated.

Dry Sorbent Injection (DSI)

Dry Sorbent Injection systems involve the injection of a dry sorbent into the flue gas ductwork following the boiler to reduce concentrations of the acid gases SO_2, hydrogen chloride and hydrogen fluoride which are regulated to prevent sulfur emissions. Sulfur oxides typically react directly with the dry sorbent, which are collected in a downstream particulate control device. The injection of hydrated lime, trona, or sodium bicarbonate into the flue gas for the removal of SO_2 and sulfur trioxide is a proven solution to reduce sulfur emissions. DSI is a system that is capable of 25 to 70 percent SO_2 removal, and higher with a fabric filter. Advantages of this control mechanism include lower capital cost, less corrosion, and a smaller footprint to those of other technologies. In comparison to other systems, the lower capital costs result in higher operating costs for equivalent SO_2 removal rates.

Unit 1 at the facility currently has in place a tray/venturi type wet scrubber that uses limestone as a sorbent. The sulfur removal efficiency is listed at 75.5 percent.[3] However, the wet scrubber at the facility is currently mothballed. The Sikeston facility has considered DSI as an alternate to restarting the wet scrubber system. The facility estimates that capital cost for installation of the DSI system would be approximately 4 to 5 million dollars and would require a new storage silo, feeder, mill, blowers and piping. Additionally there would be costs associated with the sorbent the DSI system would use, impacting normal operation and increasing maintenance expenses. Sikeston currently is able to reuse most of the ash produced at the plant. A DSI system may negatively impact the chemistry of the ash and

[2] U.S. Energy Information Administration, EIA-923; EIA923_Schedules_2_3_4_5_M_12_2019_Final; Page 5 Fuel Receipts and Costs; Fuel Receipts and Cost Time Series File, 2015, 2016, 2017, 2018, 2019, 2020 Final.
[3] U.S. Energy Information Administration, EIA-860; 6_2_EnviroEquip_Y2019; FGD; 2015, 2016, 2017, 2018, 2019, 2020 Form EIA-860 Data - Schedule 6F, 'FGD Data (Including DSI)'.

cause it to be placed in an onsite pond, or landfill. Depending on ash quality the ash produced may be subject to the federal Coal Combustion Residuals and Effluent Limitation Guidelines rules. Because DSI's have been successfully installed on several coal fired facilities throughout the country, this is a viable option for improving SO_2 removal and a dollars per ton of pollutant reduction, and has been included in the table NO_x and SO_2 Control Costs Effectiveness based on facility estimates. Additionally, estimates for a new DSI system is also included in the table NO_x and SO_2 Control Costs Effectiveness.

Spray Dryer Absorber (SDA) Flue Gas Desulfurization (FGD)

Spray Dryer Absorber Flue Gas Desulfurization technology operates using absorption as the prevalent collection mechanism. In general, the acid gas dissolves into the alkaline slurry droplets and then reacts with the alkaline material to form a filterable solid. Contact between the alkaline sorbent, usually hydrated lime, and flue gases make the gas removal process effective. The lime slurry is then atomized into droplets within the gas stream. The fine spray provides a high contact area in order for gas absorption to occur. Acid gases are then absorbed onto the atomized droplets. Evaporation of the slurry water in the droplets occurs at the same time as the acid gas absorption. The cooled flue gas then carries the dried reaction product downstream to the fabric filter. This dried reaction product can be recycled to optimize lime use. SDA FGD systems can have a 70 to 90 percent, and higher SO_2 removal efficiency.

Unit 1 at the facility currently has in place a tray/venturi type wet scrubber that uses limestone as a sorbent. The sulfur removal efficiency is listed at 75.5 percent.[3] However, the wet scrubber at the facility is currently mothballed. SDA FGD's have been successfully installed on several coal fired facilities throughout the country, and this is a viable option for improving SO_2 removal at Sikeston Unit 1.

Wet FGD

In a Wet Flue Gas Desulfurization system, flue gas is channeled to a spray tower where a fluid slurry of sorbent is injected into the flue gas. The nozzles and injection locations are designed to optimize the size and density of slurry droplets formed by the system to provide good contact between the waste gas and sorbent. Part of the water in the slurry is evaporated and the waste gas stream becomes saturated. Sulfur dioxide dissolves into the slurry droplets where it reacts with the alkaline particles. The slurry falls to the bottom of the absorber where it is collected. Treated flue gas passes through a mist eliminator and then exits the absorber to remove any caught slurry droplets. The effluent is sent to a reaction tank where the SO_2/alkali reaction is completed forming a neutral salt. After passing through the tank, systems dewater the used slurry for disposal or use as a byproduct. Most wet scrubbers have removal efficiencies in excess of 90 percent with a typical range from 80 to 98 percent.

Unit 1 at the facility currently has in place a tray/venturi type wet scrubber that uses limestone as a sorbent. The sulfur removal efficiency is listed at 75.5 percent.[3] However, the wet scrubber at the facility is currently mothballed. In 2011 the facility contacted a consultant on the feasibility of restarting their wet scrubber system and it was estimated to cost 25 million dollars to restart 2 of the 3 modules. The feasibility study did not include the possible impacts of the later Coal Combustion Residuals (CCR) and the Effluent Limitation Guidelines rules in evaluating a possible restart of this system, which with an advanced wastewater treatment system could add an additional 35 million dollars. Information from this study was used to estimate a dollars per ton of pollutant reduction and has been included in the table NO_x and SO_2 Control Costs Effectiveness. Additionally, a new FGD system is also a viable control technology and was further evaluated.

Nitrogen Oxide Emission Controls

Selective NonCatalytic Reduction (SNCR)

A Selective NonCatalytic Reduction system converts NO_x into nitrogen and water by injecting reagents at high temperature without the need of a catalyst. The system can achieve high reduction rates without the use of additional catalyst if the process is set at the correct temperature range. In this system, the ammonia or urea reagents, are injected directly into the existing flue gas pipe flow using water as a carrier in order to cover the entire cross section in the correct temperature range. This system can be an economical form of NO_x reducing technology and works for applications where a modest NO_x reduction of about 30 to 40 percent is required along with tight schedules where the flue gas temperatures are high enough (895°C-1100°C) to promote the reactions. SNCR systems can reduce NO_x emission in a range from 30 to 60 percent.

Unit 1 at the facility is currently operating a Low NO_x burners with overfire air system with a control efficiency of 55 percent. In 2009 the facility set up a contract with a consultant to evaluate flue gas characteristics to determine the capabilities of an SNCR system. In the testing of SNCR, Sikeston utilities operated a temporary urea injection and partial SNCR system. Maximum removal efficiencies were shown to be 33 percent at a cost of 1,151 dollars per ton. The testing also showed buildup of stalactites at the furnace room and convection pass due to the by product from the urea injection system. This resulted in possible tube damage in the boiler when the build-up formations dropped to the boiler floor. Additionally, it was found that the urea injection and ammonia slip adversely affected the ash quality and its potential for sale. Because SNCR technology is not a viable option it was not further evaluated, however a dollars per ton of pollutant reduction based on facility estimates has been included in the table NO_x and SO_2 Control Costs Effectiveness.

Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction technology is a proven and effective method to reduce NO_x emissions from coal fired power plants. In general, all through the combustion process, the nitrogen that occurs naturally in the coal, and the nitrogen and oxygen existing in the combustion air, combine to form NO_x. Before being released to the atmosphere, the exhaust gas proceeds through a large catalyst where the NO_x reacts with the catalyst and ammonia and is converted to nitrogen and water. Selective catalytic reduction typically removes between 75 to 85 percent of the NO_x that is in the exhaust gas of a coal-fired power plant but can be as high as 90 percent.

Unit 1 at the facility is currently operating a Low NO_x burners with overfire air system with a control efficiency of 55 percent. Because SCR technology is a viable option it was further evaluated.

The following table summarizes both the technologies that have been eliminated and evaluated for further study as discussed above and the expected control efficiency.

Technology	Evaluated Further	Assumed Control Efficiency (%)
Coal Washing	No	-

Technology	Evaluated Further	Assumed Control Efficiency (%)
Coal Switching	No	-
Dry Sorbent Injection (facility estimates)	Yes	-
Dry Sorbent Injection (New)	Yes	80
Spray Dryer Absorber Flue Gas Desulfurization	Yes	~90
Wet Flue Gas Desulfurization (Existing, facility estimates)	Yes	-
Wet Flue Gas Desulfurization (New)	Yes	~95.5
Selective NonCatalytic Reduction (facility estimates)	No	40
Selective Catalytic Reduction	Yes	85

Four Factor Analysis

Costs of Compliance

Cost assessments for the control technologies evaluated were made utilizing the EPA Air Pollution Control Cost Manual Section 4, NO_x Controls, updated in 2019, and Section 5, SO_2 and Acid Gas Controls, updated in 2021. Estimates were also obtained by completing spreadsheets for SO_2 and NO_x controls using EPA's Control Cost Manual, and for SCR control equipment, EPA's Clean Air Markets Division Retrofit Analyzer tool, last updated in 2019.[4] The complete costs derived from the Cost Manual and retrofit analyzer tool may be found in the appendices for Unit 1. The Capital Recovery Factor was based on an interest rate of 3.25 percent and the unit's useful life for Unit 1. A typical overall lifespan for an electric generating unit of 55 years was used, however there is no enforceable shutdown date codified.[5] When given, facility cost estimates were used. Cost estimates derived from the spreadsheet were converted to 2021 dollars for all control technology equipment. The below tables show the estimated cost of control for each selected control technologies and remaining useful life scenario as discussed in the main SIP document. The last column shows that the cost effectiveness of all control technologies exceed the cost effectiveness threshold of $3,658 and $5,370 per ton for removed for SO_2 and NO_x, respectively.

For DSI, the Air Program assumed that the facility will utilize milled Trona along with the existing electrostatic precipitator (ESP). It is likely that the existing ESP will not be able to handle the increase of particulate matter emissions associated with using the Trona; therefore, the facility needs to either upgrade the ESP or install a baghouse. The Air Program did not take into consideration the cost of upgrading the ESP or installing a baghouse in this cost analysis. Finally, the Air Program used 2021 CEPCI to project to control cost from 2016.

[4] U.S. Environmental Protection Agency, Clean Air Markets Division, Retrofit Cost Analyzer, 2019.
[5] U.S. Energy Information Administration, EIA-860; 3_1_Generator_Y2019; Retired and Canceled; 2015, 2016, 2017, 2018, 2019 Form EIA-860 Data - Schedule 3, 'Generator Data' (Retired & Canceled Units Only).

NO_x and SO_2 Control Costs and Effectiveness

Control Equipment	Boiler	Control Efficiency (%)	Remaining Useful Life (year)	Capital Costs	Annualized Costs	Emission removal (ton)	Cost Effectiveness (2021$/removed ton)
Wet FGD	Unit 1	95.5	11.67	$185,127,443 ($22,200,000)**	$26,746,245	4,110	$6,507
SDA	Unit 1	90	11.67	$161,590,802	$23,429,170	3,874	$6,049
DSI with ESP	Unit 1	80	13.5	$21,070,134 ($4,000,000 to $5,000,00)***	$14,297,095	3,443	$4,152
Wet FGD*	Unit 1	95.5	25	$185,127,443	$18,359,971	4,110	$4,467
SDA*	Unit 1	90	25	$161,590,802	$16,109,107	3,874	$4,159
DSI with ESP*	Unit 1	80	25	$21,070,134	$13,588,131	3,443	$3,946

*Cost estimates based on remaining useful life based on EPA's control cost manuals
**Sikeston Power Station estimate to restart the existing Tray/Venturi type wet scrubber
***Sikeston Power Station estimate

Control Equipment	Boiler	Control Efficiency (%)	Remaining Useful Life (year)	Capital Costs	Annualized Costs	Emission removal (ton)	Cost Effectiveness (cost/removed ton)
SCR	Unit 1	85	12.5	$97,055,513	$11,118,507	774	$14,369
SCR*	Unit 1	85	30	$97,055,513	$6,663,659	774	$8,612
SNCR	Unit 1						$1,408**

* Cost estimates based on remaining useful life based on EPA's control cost manuals

Time Necessary for Compliance

The time necessary for compliance is the period needed for full implementation of the evaluated feasible control options. This would include the time needed to develop and finalize the regulations, as well as the time needed to install the selected control equipment. The time needed to install the control equipment includes time for equipment procurement, design, fabrication, and installation. Estimates for compliance ranged from 30 months for Dry Sorbent Injection, and 52 months each for Spray Dryer Absorber Flue Gas Desulfurization, Wet Flue Gas Desulfurization, and 42 months for a Selective Catalytic Reduction.

Energy Impacts

Dry Sorbent Injection: DSI systems would require auxiliary power at the plant by use of electricity to operate fans, pumps, and other equipment. Additional fuel would be expended at the facility to produce this electricity. Additionally, there would be a heat rate penalty associated with this technology.

Spray Dryer Absorber Flue Gas Desulfurization: Lime used in dry FGD systems must be hydrated prior to use, increasing the facility's overall consumption of electricity.

Wet Flue Gas Desulfurization: The primary energy impacts of the wet FGD alternative consists of the additional electrical load resulting from pumps and reagent preparation. As a result, heat input to the boiler would need to increase to compensate for the increased auxiliary power requirements while achieving the same net plant output.

Selective Catalytic Reduction: SCR systems would require additional electricity to operate fans, pumps, and other equipment. If the electricity were generated on site, additional fuel would be used by the source to produce this electricity, or it would need to would come from the electric grid. If the additional electricity came from the plant, the boiler heat input would have to increase to compensate for the increased auxiliary power usage.

Non-Air Quality Environmental Impacts of Compliance

Dry Sorbent Injection: This technology would require additional precautions for fuel handling and waste systems to prevent non-air environmental impacts due to increased effluents in wastewater discharges and storm water runoff.

Spray Dryer Absorber Flue Gas Desulfurization: Using this control technology would require the facility to handle limestone for injection in the unit, and pebble lime for use in the dry scrubber. The lime used in this technology would need to be hydrated prior to use, raising the facility's overall water usage. If polluted water is released from the facility, wastewater treatment may be necessary.

Wet Flue Gas Desulfurization: This technology would increase calcium sulfate solids disposal. Typically solid wastes generated using this technology are dewatered and disposed of in landfills. Some of these control systems may be able to generate a gypsum byproduct that can be sold in the open market. If the gypsum cannot be sold, proper disposal would then be required. Significant water use for this technology may require treatment before being discharged in order to meet water effluent limits.

Selective Catalytic Reduction: The operation of an SCR system could have non-air environmental impacts due to the storage of ammonia at the facility. This may cause the potential for accidents due to an ammonia release. Post-control NO_x systems such as SCR would require additional safeguards for proper handling of reducing reagents such as urea or ammonia. Depending on the ammonia type, concentration, and quantity used, the material may also be subject to regulations such as the hazardous substances under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), and Clean Water Act.

Summary

In conclusion, based on a review of possible and feasible options to reduce SO_2 and NO_x emissions at Unit 1, the Air Program has determined that there are no cost-effective methods of SO_2 and NO_x reduction for this facility. All Class I areas impacted by sources in Missouri have made steady and significant improvement in visibility, and modeling shows they are projected to be below, or well below, their uniform rate of progress (URP) glidepaths in 2028. Based on the four factor analysis completed in this report, the Air Program is proposing to maintain current operational practices consistent with the parameters and limits in the Sikeston Power Station Air Pollution Control Title V Permit to Operate.

**All control cost estimate calculations for wet FGD, SDA, and DSI for both remaining useful life (RUL) scenarios are provided in the attached spreadsheets

Sikeston Unit 1 NOx SCR-EPA-RUL.xlsm
Sikeston Unit 1 NOx SCR-Original-RUL.xlsm
Sikeston Unit 1 SO2 DSI-EPA-RUL.xlsx
Sikeston Unit 1 SO2 DSI-Original-RUL.xlsx
Sikeston Unit 1 SO2 SDA-EPA-RUL.xlsm
Sikeston Unit 1 SO2 SDA-Original-RUL.xlsm
Sikeston Unit 1 SO2 wet_FGD-EPA-RUL.xlsm
Sikeston Unit 1 SO2 wet_FGD-Original-RUL.xlsm

Sikeston additional information in response to the FLMs and EPA's comments during the 60-day formal consultation period

1. What are the revenues lost due to not being able to sell fly ash because of adding Dry Sorbent Injection (DSI) SO_2 control? What are the hauling, landfill, and water costs?

   Spreadsheet attached (Attachment A) covers revenue losses. These values come from a spreadsheet used for annual EIA-923 reporting. Not only does this result in offset revenue, but it also affects our beneficial reuse contract and negatively impacts other industries by reducing or eliminating a viable source of concrete/cement fill. While DSI controls could possibly help to reduce SO_2 emissions, the net result will be an increase in landfilled ash and an amplified strain on an already struggling public power generator. Our ash marketer has seen the ash impacts of DSI and stated, “Trona has been a death sentence for ash, in our experience. Basically full-time landfill ash at that point.”

   There are a variety of factors that affect the cost of landfilling ash. Transportation and distance, volume, and dusting, just to name a few. Our ash marketer reported typical costs around \$50 – \$100/ton for off-site landfills, depending upon the distance. Disposal costs are higher when the ash is “unconditioned,” meaning ash that does NOT go through a pug mill. Unconditioned ash would also add the cost of geotube storage.

   Generally speaking, for the application of a sorbent for SO_2 control at a generator the size of Sikeston’s unit, aside from the additional cost of the injected material and the actual system costs, you would be adding around \$2.5MM in new annual O&M costs and removing \$300,000 (or more) from annual beneficial reuse for the changes in ash handling.

2. Due to DSI SO_2 control, what is the estimated cost to convert the current Electrostatic Precipitator (ESP) to a Baghouse, or adding a new Baghouse?

   Per Burns & McDonnell:

   a. New fabric filter: \$45M - \$75M, plus Owner costs
   b. New ESP: \$36M - \$60M, plus Owner costs
   c. ESP rebuild: \$29M - \$49M, plus Owner costs

3. Please provide supporting documentation on the estimate given to restart the Flue-Gas Desulfurization (FGD) unit. What would be the cost of a new water treatment plant due to FGD?

   I’ve attached the 2011 S&L study (Attachment B - 2011 Sikeston FGD Re-Start Report.pdf) detailing the scrubber restart evaluation. This study concluded a \$22.2 million dollar cost to rehabilitate and restart the existing FGD. Additionally, subsequent reports (Attachment C - 2020 RUL Study.pdf) have adjusted the 2011 results to reflect “2017 dollars,” now at \$25 million. The new water treatment plant wasn't considered in 2011, simply because of the uncertainty in the ELG rule progress. Regardless, subsequent reports have addressed this in a high level capacity, based on engineering history and known plant variables, included as an attachment (Attachment D - 2017 Regulatory Review.pdf).

Attachment A

Attachment A

Annual Ash Sales by Month						
	2015	2016	2017	2018	2019	2020
JAN	$ 17,492.82	$ 30,980.55	$ 49,045.43	$ 33,591.43	$ 19,381.84	$ 25,483.66
FEB	$ 12,443.50	$ 21,239.38	$ 23,702.36	$ 15,984.86	$ 15,219.82	$ 17,088.32
MAR	$ 9,904.04	$ 12,474.56	$ 13,663.90	$ 8,114.44	$ 11,352.70	$ 41,723.08
APR	$ 7,928.31	$ 16,690.39	$ 22,757.14	$ 12,429.42	$ 29,564.72	$ 23,167.00
MAY	$ 5,615.83	$ 9,871.98	$ 27,500.54	$ 21,222.90	$ -	$ 32,529.10
JUN	$ -	$ 20,716.54	$ 25,561.94	$ 8,556.39	$ -	$ -
JUL	$ 9,048.46	$ 18,354.15	$ 21,243.13	$ 16,863.54	$ 51,868.18	$ 64,376.68
AUG	$ 28,589.37	$ 3,287.11	$ 29,759.54	$ 26,273.41	$ 19,070.60	$ 27,657.23
SEP	$ 33,861.37	$ 4,210.10	$ 23,097.62	$ 31,355.07	$ 11,414.71	$ 37,253.77
OCT	$ 26,194.47	$ 6,272.29	$ 35,925.06	$ 43,672.94	$ 20,987.89	$ 37,741.43
NOV	$ 39,497.48	$ 29,438.72	$ 40,039.71	$ 35,960.00	$ 37,901.22	$ 33,979.62
DEC	$ 35,699.22	$ 35,011.62	$ 33,652.21	$ 53,866.45	$ 54,403.70	$ 23,423.28
	$226,274.87	$208,547.39	$345,948.58	$307,890.85	$271,165.38	$364,423.17

Attachment B

2. SULFUR DIOXIDE COMPLIANCE

2.1 FGD PERFORMANCE IN THE NEW OPERATING MODE

Re-starting the FGD system involves a change in operation from the way it was previously operated, in several ways:

- The coal has changed dramatically, from 2.8% sulfur Illinois coal to 0.31% sulfur Powder River Basin coal.
- The original objective of meeting a 1.2 lb. SO_2/MMBtu emission limit (76% reduction from the high-sulfur coal) has changed to achieving lowest feasible emissions for least consumption of allowances, say 95% reduction from the low-sulfur coal.
- Disposal pond is full and pond disposal of an objectionable paste material has been rendered obsolete by the option of producing a fully oxidized, commercial gypsum product.

To demonstrate the expected performance of the Sikeston FGD system in the new operating mode, Sargent & Lundy developed a mass balance model of the Sikeston FGD system. S&L's standard wet FGD mass balance program was modified to match the original B&W configuration. This model was tested and tuned to match the mass balance B&W originally provided. Referring to Appendix A, the mass balance for this case is titled "WFGD System – 2.8% Sulfur, 4.8 lbSO_2/MMBtu – 100% Flue Gas Treated". The mass balance was then modified to show the re-start case:

- Coal was changed to the current 0.31% sulfur Powder River Basin coal.
- Primary (hydrocyclone) and secondary (vacuum drum filter) gypsum dewatering was added to the process, to support commercial sale of the by-product.

This case is titled "WFGD System – 0.31% Sulfur, 0.691 lbSO_2/MMBtu – 100% Flue Gas Treated".

SPS personnel indicated the desire to maintain flexibility in fuel procurement, so they identified a popular fuel to use as a "worst case." To demonstrate this worst-case coal, the case titled "WFGD System – 0.35% Sulfur, 0.857 lbSO_2/MMBtu – 100% Flue Gas Treated" was prepared.

The questions to be answered by these mass balances are discussed below.

- What is the maximum SO_2 removal the system can reliably achieve?

Both the 0.31% sulfur case and the 0.35% sulfur case show approximately 94% SO_2 removal without the use of forced oxidation.

- Can the system produce a gypsum oxidation level acceptable to agricultural users, without the addition of an oxidation air system?

Both the 0.31% sulfur case and the 0.35% sulfur case show that the oxygen in the flue gas is sufficient to produce a minimum of 90% calcium sulfate gypsum, which should be acceptable for agricultural use.

- Will the increase in flue gas flow with the PRB coals be so much that the ID fans do not have sufficient capability?

The worst-case mass balance shows that the flue gas flow increases from 2.59 million lb/h (435,000 acfm) to 2.73 million lb/h (448,000 acfm), which is only a 3.1% increase.

Sargent & Lundy examined the ID fan curve, which is not well annotated. We believe the reference point at 483,000 acfm and 2,890 feet of air (30.25 inches of water) is the test block condition. A system head curve (current operation with FGD bypassed) was generated and reproduced for the fan test that demonstrated an average (for the two fans) of 518,000 acfm/24.1 in. water ID fan capability. On this curve, the current operating point is shown at 448,000 acfm/26.2 in. wc. Based on historical data, S&L developed a system head curve for the system including the FGD system losses. The historical, high-sulfur coal operating point is shown on the “with FGD” system curve at 435,000 acfm/24.6 in. water. The projected operating point for PRB coal with FGD is shown on the curve at 448,000 acfm. This operating point appears to be well within the capability of the fan.

S&L checked the power demand of the fan at the new operating point. Power demand at 448,000 acfm/26.2 in. water will be 2,125 hp. The fan motors are rated at 2500 hp each.

2.2 FLUE GAS DESULFURIZATION (FGD) REHABILITATION

The Sikeston FGD system was built in 1978 as a part of the overall Sikeston Power Station (SPS) construction. It operated from 1981 thru 1997 burning the original design Southern Illinois No. 6 coal containing 2.8% sulfur (4.8 lb. SO_2/MMBtu). The FGD system used Southern Illinois limestone having a high calcium carbonate (>95%) content. The system was shut down in 1998 when the plant switched to burning Powder River Basin (PRB) coal containing approximately 0.31% sulfur (0.7 lb. SO_2/MMBtu). The FGD system has been maintained in a cold state since shutdown.

Operating in natural oxidation mode on 2.8% sulfur coal, the Sikeston FGD system produced a mixed by-product of approximately 30-35% gypsum and 65-70% calcium sulfite. The spent slurry was pumped to the plant's dewatering pond system through the spent slurry pumps and booster pumps. When the FGD system was shut down, pond duty was limited to ash disposal and small quantities of waste water.

A condition assessment of the Sikeston FGD system equipment was conducted by Sargent & Lundy LLC staff during October 2011. The assessment was performed by visiting the site, visually inspecting the equipment (where possible), and interviewing BMU staff who were present when the scrubber was last operated to obtain plant information and historical scrubber operation and maintenance information.

Two portions of the FGD system that were not inspected during the site visit are:

- Limestone receiving, conveying and silo equipment
- Wet ash pond system

These systems were not included in the contract scope. Conversations with the plant staff indicated that the condition of the limestone receiving and storage equipment is acceptable, with specific condition-related maintenance required to the conveying system. The ash ponds are nearing their design storage capacity and cannot be used for future storage of the gypsum produced from the scrubbing process.

The FGD system, which was inspected for existing condition, consists of the:

- Inlet and Discharge Flue Gas Absorber Ductwork,
- Primary and Secondary Gypsum Dewatering,
- FGD Control System,
- Electrical Distribution System,

- FGD Building,
- Continuous Emission Monitors
- Chimney Flue (Wet),
- and FGD Scrubber Modules.

The condition inspection information of the scrubber modules A, B,C and Common Equipement is located in Appendix B.

2.3 RECOMMENDED FGD REHABILITATION AND ASSOCIATED COST ESTIMATE

2.3.1. System-by-System Rehabilitation Cost Breakdown

FGD System Rehabilitation		

The FGD System consists of the following subsystems:
• Common Systems
• Limestone Preparation and Feed System
• A and (B or C) Quencher/Absorber Modules
  o Quencher Process Equipment
  o Absorber Process Equipment
Each subsystem section contains recommendations for required repairs and/or upgrades which are necessary to restart the FGD System.		

FGD System Rehabilitation		
Total FGD System Estimated Cost	**$18.0 million**	
(Total scrubber cost is sum of Common Systems, Limestone Preparation & Feed System, A and (B or C) Quencher/Absorber Modules, and New FGD System Equipment.)		
Common System Rehabilitation		
Total Common Estimated Cost	**$5.6 million**	
(Total common system cost is sum the rehabilitation of the flue gas ductwork; gypsum dewatering; process control; electrical distribution; FGD building, wet chimney flue; and wet flue continuous emission monitors.		

Inlet and Discharge Flue Gas Ductwork Rehabilitation	
	Recommendation
Inlet Duct and Dampers from Air Heaters to Quencher Inlet:	No work required on A, B and C modules ductwork and dampers.
Outlet Duct and Dampers from Absorber Outlet to Breeching Ductwork	• Replace B & C absorber duct with fiberglass duct. • Install three new absorber double louver (C-276) dampers Replace breeching to chimney with fiberglass.
Spent Slurry System Rehabilitation	
	Recommendation
Primary Spent Slurry Pumps	Inspect pump and motor and repair/overhaul as required.
Secondary Spent Slurry Pumps	Demolish
Hydrocyclone	New System
Scrubber Control System Rehabilitation	
	Recommendation
FGD Control Room	• Use existing control panel as termination point for interfacing with new DCS I/O cabinet • Terminate field cabinet wiring with existing control panel terminations. • Install DCS cabinet for interface with central control room. • Install data cables between FGD building and central control room.

Control Field Devices	• Replace existing data transmitters (pressure, temperature, flow) • Replace local field instruments (pressure, temp, rotameters) • Replace all primary orfices. • Rebuild or replace all valve actuators.
Electrical Distribution System Rehabilitation	
	Recommendation
4 kV System	• Inspect and test 4 kV circuit breakers • Repair and/or replace (if required).
480V and Lower Voltage Systems	• Inspect and test 480V and lower voltage circuit breakers • Repair and/or replace (if required).
Electric Cable Distribution Tray and Conduit System	Repair and replace light fixtures, switches and outlets (if required).
Scrubber Building Rehabilitation	
	Recommendation
FGD Building Enclosure and Structural Steel	Repair the corroded bracing on first level of building.
Chimney Flue (wet) Rehabilitation	
	Recommendation
Interior Flue (wet)	Remove and replace flake glass coating on top and bottom 30 ft interior of steel flue.
Exterior Shell	No work required on exterior chimney concrete shell.

Continuous Emissions Monitors (Wet Flue) Rehabilitation		
	Recommendation	
Wet Flue Continuous Emission Monitor	No work required on wet flue CEMS and stack flow monitor.	
Limestone Preparation and Feed System Rehabilitation		
Total Limestone Estimated Cost		
(Total limestone cost is sum of the limestone preparation system and feed system cost.)		
Limestone Preparation Rehabilitation	**Recommendation**	
Mill feeder	• Inspect belt, drive and motor. • Repair/overhaul as required.	
Ball Mill		
Drum Bearings and Liner	• Replace drum bearings • Install new drum liners.	
Gear Drive and Motor	• Inspect gear drive and motor. • Repair/overhaul as required.	
Install New Grinding Ball Charge	Fill mill drum with new grinding balls.	
Mill Product Tank		
Interior Surface	• Remove rubber lining. • Install new flake glass interior coating.	
Exterior Surface	No work required	
Agitator and Motor	• Inspect agitator drive and motor. • Repair/overhaul as required.	
Mill Product Pumps and motors	• Inspect pump and motor • Repair/overhaul as required.	
Product Classifier	Replace all hydrocyclones in cluster	

Feed Slurry System Rehabilitation	**Recommendation**
Limestone Slurry Storage Tank	
Interior Surface	• Remove rubber lining. • Install new flake glass interior coating.
Exterior Surface	No work required.
Agitator and Motor	• Inspect agitator drive and motor. • Repair/overhaul as required.
Slurry Transfer Pumps and Motors	• Inspect pump and motor • Repair/overhaul as required.
Slurry Transfer Piping	Replace with fiberglass pipe.

A and B or C Quencher/Absorber Modules Rehabilitation	
Total A & B or C Quencher/Absorber Modules Rehabilitation Estimated Cost	**$12.4 million**
(Total module cost is sum of A Module and either B or C Module rehabilitation cost.)	
A Quencher/Absorber Module Train Estimated Cost	**$2.6 million**
(Total A module cost is sum of all A module sub-system rehabilitation costs.)	
Quencher Process Equipment	
Quencher Portion of Module	**Recommendation**
Interior Surface:	No work required.
Exterior Surface:	• No work required. • Monitor seam separation for further degradation.
Throat Sprays:	• No work required
Sump Downcomer	• No work required

Quencher Recirculation Tank		
Interior Surface	• No repair to existing flake glass lining interior lining required. •	
Exterior Surface	• Replace bottom two feet of tank side wall if required. • Coat new section of tank walls with flake glass lining.Paint replaced portion of tank wall. • Remove curb from tank foundation. • Add tank overflow pipe and route to floor drain.	
Agitator and Motor	• Inspect agitator drive and motor. • Repair/overhaul as required.	
Quencher Recirculation System Pump and Motor	• Inspect pump and motor • Repair/overhaul as required.	
Distribution Piping to Quencher Sprays	Replace rubber lined pipe with fiberglass pipe.	
<u>Absorber Process Equipment</u>		
Absorber Portion of Module	**Recommendation**	
Interior Surfaces	No work required.	
Exterior Surfaces	No work required.	
Slurry Sprays	No work required.	
Trays	No work required.	
Mist Eliminators		
Secondary (Upper)	Replace with improved element.	
Primary (Lower)	No work required.	
Mist Eliminator Sprays		
Secondary (Upper)	No work required.	
Primary (Lower)	No work required.	
Sump Downcomer	No work required	

Absorber Reaction Tank		
Interior Surface	• No repair to existing flake glass lining interior lining required. •	
Exterior Surface	• Replace bottom two feet of tank side wall. • Coat new section of tank walls with flake glass lining. • Paint replaced portion of tank wall. • Remove curb from tank foundation. • Add tank overflow pipe and route to floor drain.	
Agitator and Motor	• Inspect agitator drive and motor. • Repair/overhaul as required.	
Absorber Recirculation Pumps and Motors:	Inspect pump and motor and repair/overhaul as required.	
Distribution Piping to Absorber Sprays	Replace rubber lined pipe with fiberglass pipe.	
B or C Module Estimated Cost	**$9.8 million**	
(Total B or C module train cost is sum of all sub-system costs for one train.)		
Quencher Process Equipment		
Quencher Portion of Module	**Recommendation**	
Interior Surface	• Remove rubber lining • Install new flake glass interior coating	
Exterior Surface	• No work required. • Monitor seam separation for further degradation.	
Throat Sprays	• No work required	
Sump Downcomer	Replace rubber lined pipe with fiberglass pipe.	

Quencher Reaction Tank	
Interior Surface	• Remove rubber lining. • Install new flake glass interior coating.
Exterior Surface	• Paint replaced portion of tank wall. • Remove curb from tank foundation. • Add tank overflow pipe and route to floor drain.
Agitator and Motor	• Inspect agitator drive and motor. • Repair/overhaul as required.
Quencher Recirculation System Pump and Motor	• Inspect pump and motor. • Repair/overhaul as required.
Distribution Piping to Quencher Sprays	Replace rubber lined pipe with fiberglass pipe.
<u>Absorber Process Equipment</u>	
Absorber Portion of Module	**Recommendation**
Interior Surfaces	• Remove rubber lining. • Install new flake glass interior coating.
Exterior Surfaces	No work required.
Slurry Sprays	No work required.
Trays	No work required.
Mist Eliminators	
Secondary (Upper)	Replace with improved element.
Primary (Lower)	No work required.
Mist Eliminators Separator Sprays	
Secondary (Upper)	No work required.
Primary (Lower)	No work required.
Sump Downcomer	Replace rubber lined pipe with fiberglass pipe.

Absorber Reaction Tank	
Interior Surface	• Remove rubber lining. • Install new flake glass interior coating.
Exterior Surface	• Paint replaced portion of tank wall. • Remove curb from tank foundation. • Add tank overflow pipe and route to floor drain.
Agitator and Motor	• Inspect agitator drive and motor. • Repair/overhaul as required.
Absorber Recirculation Pumps and Motors	• Inspect pump and motor. • Repair/overhaul as required.
Distribution Piping to Absorber Sprays	Replace rubber lined pipe with fiberglass pipe.

2.3.2. Estimated Cost for New FGD System

The cost for a new FGD system to replace the mothballed system was estimated using $700 per kilowatt. This construction cost estimate for a new scrubber is based on recent industry construction experience. The plant gross electrical capacity is 251.8 MW (obtained from recent turbine heat rate information). The cost to construct a new scrubber on the Sikeston plant site is $176,260,000.

2.4 FGD QUENCHER CONVERSION

The quencher is an essential part of the scrubber process. It cools the flue gas to ensure the rubber lining and plastic components of the absorber section of the scrubber are not damaged. At the San Miguel power station, S&L converted the venturi quencher to an open spray quencher because the unit was ID fan limited. The conversion reduced the pressure drop through the quencher by more the 3 inches water. The following explains why this is not necessary at SPS.

The design of the early Babcock & Wilcox FGD system is unique in that it features a separate quencher section, ahead of the absorber. The quencher uses the venturi concept, which creates a high-velocity turbulent zone where slurry is introduced. The turbulence and high pressure drop in the venturi cause thorough mixing of the slurry into the flue gas. This assures that all of the flue gas is cooled before it reaches the rubber lining of the absorber section.

Experience has demonstrated to the industry that the thoroughness of mixing in the venturi quencher is more than is necessary to adequately quench the flue gas. It carries with it the penalty of substantial restriction to the gas flow, which may limit fan capacity and also consumes valuable electricity. In Section 2.1, above, Sargent & Lundy has reviewed the application of the existing ID fans to the combination of the higher flue gas flow when burning PRB coal and operation of the FGD system. That review showed that the ID fans are capable of handling this slightly higher design point without modification. This finding means that conversion of the quencher is not necessary to maintain ID fan margin. Conversion of the quencher would have to be justified based solely on reduced electrical consumption.

The design of the quencher/absorber/sump vessel is unusual, in that it is center-supported, with the sump hanging from the support and the quencher and absorber resting on the support. In addition, it is unusual in that the support girders are integral with the lower part of the walls of the quencher and absorber. In the case of the quencher, this means the girders are canted to follow the taper of the expanding portion of the venturi (see Figure 2-R). To avoid disturbing the girder, the taper of the bottom of the venturi must remain, so the walls of the new quencher will not be perfectly vertical. The figure shows how the gunite-lined walls of the venturi would be removed down to the girder, and replaced with new tile-lined walls that eliminate most of the taper. This is similar to the conversion S&L did at San Miguel, except that the new San Miguel quencher was built with unlined solid C-276 (nickel) plate. Since that time, C-276 has become prohibitively expensive. Also, the C-276 experienced severe abrasion in the area of slurry impingement. Before and after photos of the San Miguel quencher are shown in Figure 2-S.

Figure 2-1 – Quencher Conversion

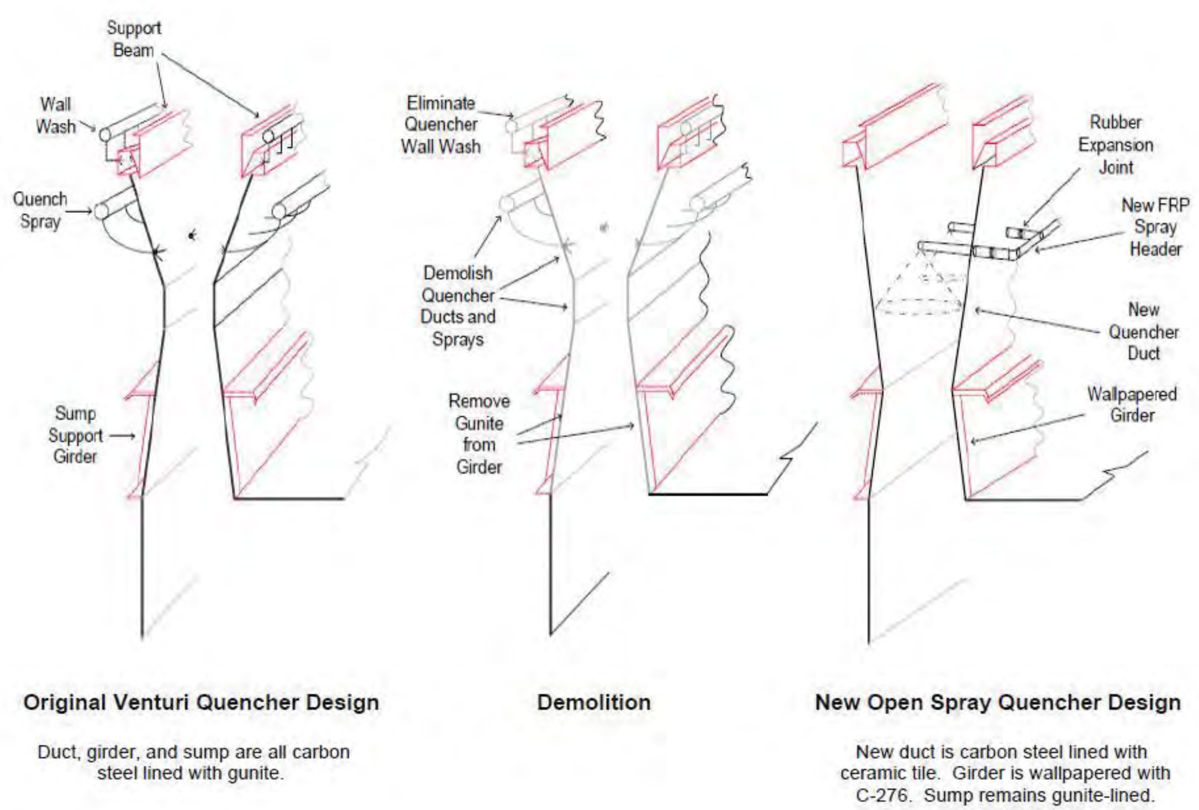


Figure 2-2 – San Miguel Quencher Section

Left Photo: Original Venturi Quencher Right Photo: Open Spray Quencher

In a conversion to open spray quencher, the quencher sprays would also be changed. The existing sprays are large-droplet sprays that depend upon the turbulence of the venturi to achieve liquid-gas contact. The open spray quencher would have fine-mist spray nozzles (similar to those already in the absorber zone) centered in the quencher duct. Internal spray piping would be C-276, while external piping would be FRP, with a rubber expansion joint at the connection to the internal piping. This design would differ slightly from San Miguel, in that there would be only a single quencher spray level, whereas two levels were employed there. A single level is expected to be adequate to achieve quenching and very little SO_2 absorption occurs in a co-current spray zone. At San Miguel, accommodation of two quencher spray levels, combined with the residual taper of the walls, made it difficult to avoid wall zones with high erosion potential. Also, San Miguel experienced dried slurry from the upper level accumulating on the nozzles of the lower level. These problems would be avoided with a single spray level design. The quencher wall wash feature would be eliminated. However, again, the quencher conversion does not appear to be necessary or attractive for Sikeston Power Station.

S&L estimated the cost of the quencher conversion, as shown in Table 2-1, in the event the quencher required modification. The estimated \$5.9 million conversion is not necessary at SPS to restart the FGD system and achieve 94% SO_2 removal.

Table 2-1 – Cost to Convert the Quenchers from Venturi to Open Spray Quenchers

Conversion of 2 Quenchers	$5.9 million

2.5 FGD MIST ELIMINATOR UPGRADE

2.5.1. Mist Eliminator Elements

Sargent & Lundy has investigated the design, performance and condition of the Sikeston FGD Mist Eliminators (MEs). S&L recommends changing the second stage ME elements. The design of the mist eliminators is typical of these early units. The elements are installed in a flat, horizontal array, as shown in Figure 2-3. Later designs tip the elements, so they drain from a single point, rather than the whole bottom edge. This reduces the tendency to form stalactites if any scaling occurs. The inspection indicated no issues with the flat arrangement, so S&L recommends retaining it as-is.

Figure 2-3 – Existing Mist Eliminators

However, Sikeston Power Station staff indicated there have been issues with opacity. Current operation, bypasses the FGD system, so the current opacity issue is strictly about ash passing through the electrostatic precipitator (ESP). Operation with the FGD system will affect opacity in two ways:

- Ash Removed in the Absorber

The FGD system will inadvertently remove some ash. This is believed to be larger particles, but S&L expects the issue consists mainly of fine particulate.

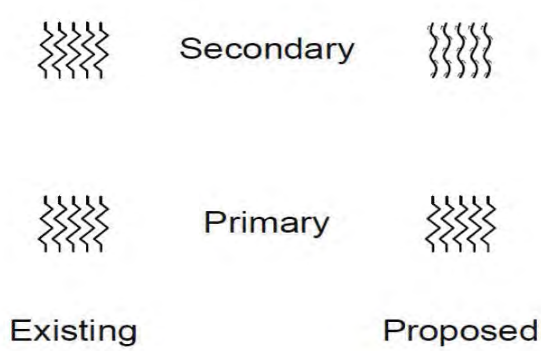
- Mist Added in the Absorber

Water mist also counts as particulate. To achieve particulate emission requirements, it is important to have effective FGD mist eliminators.

The Sikeston mist eliminator design is also typical in that it uses chevron elements. These elements are used both for the first-stage ME and for the second-stage ME. Mist eliminator elements are shown in Figure 2-4. The existing Sikeston FGD ME elements are chevrons for both stages, as shown on the left. The diagram on the right shows chevrons for the first stage (bulk mist eliminator), but J-hook elements for the second stage (fine mist eliminator). S&L recommends changing the second stage ME elements.

Figure 2-4 Mist Eliminator Elements

Chevrons for Primary and Secondary **Chevrons for Primary; J-Hooks for Secondary**



The cost of replacements of the elements for the secondary mist eliminators in two absorbers is included in the FGD rehabilitation cost.

2.5.2. Mist Eliminator Wash

Sargent & Lundy recommends resuming operation of the mist eliminator wash in the same way it was oprated previously. Mist eliminator washing at Sikeston generally follows accepted practice. Sprays are provided on the leading face (bottom) of the primary mist eliminator and another set between the primary and secondary mist eliminators. These latter have downward-facing nozzles to rinse the primary mist eliminator and upward-facing nozzles to wash the secondary mist eliminator. See Figure 2-5. S&L saw no evidence of the isolated headers and solenoid valves that would indicate zone washing, so it is assumed the mist eliminators are washed as a single zone. Because of the open-loop operation on the pond, minimizing mist eliminator wash to achieve water balance has not been an issue. In the future, it is anticipated that the quantity of water leaving with the by-product will still be high enough that it will not be necessary to ration mist eliminator washing to maintain a water balance.

Figure 2-5 – Between-Stage Mist Eliminator Wash Nozzles

The water used for mist eliminator washing was of a fairly high order, a mixture of the following sources:

- Cooling Tower Blowdown
- Service Water
- Clarified Recycle Water

According to accounts from previous operation, as well as the evidence from observation, this water was successful in cleaning the mist eliminators without creating scale buildup or other problems.

2.6 GYPSUM DEWATERING UPGRADE

The Sikeston FGD system was designed to produce a low-grade product. Natural oxidation of the by-product from the 2.8% sulfur coal produced a by-product that was a mixture of two different crystal types:

- Calcium Sulfate ($CaSO_4$), or gypsum   flat, plate-type crystals
- Calcium Sulfite ($CaSO_3$)   rod-shaped crystals

The mixture has no commercial use. Also, the dissimilar crystal types trap water between them, making the mixture retain water, which creates a paste-like consistency. See Figure 2-6. This material is best disposed of in ponds. This explains why the scrubber was built for pond disposal.

Figure 2-6 – Mixture of $CaSO_3$ and $CaSO_4$ Crystals (under magnification)

Two things have changed. The scrubber will now run on flue gas from combustion of PRB coal. This coal contains very little sulfur, plus it requires somewhat higher air flow for combustion. The combination means that there is sufficient oxygen in the flue gas to achieve very high oxidation of the by-product without injecting additional air. The by-product will be over 90% calcium sulfate (gypsum). This by-product is desirable in two respects:

- It is a product with several commercial uses
- It dewaters easily because the crystals are of uniform shape that allows moisture to escape from between them

Sikeston Power Station personnel have worked to establish the feasibility of producing gypsum as an agricultural soil supplement in the Mississippi Valley. Gypsum has two benefits in that it neutralizes acidic soil and it provides sulfur as a nutrient. Producing gypsum for agricultural use is a specific application with characteristics slightly different from producing gypsum for wallboard manufacture or for cement manufacture. Specifically:

- The gypsum need not be washed free of chloride and fine gypsum crystals.
- The gypsum need not be dewatered to less than 10% moisture; 15% is acceptable.
- The gypsum must be stockpiled, for delivery during one month of the year.

Sargent & Lundy sees two possible dewatering schemes to suit these parameters.

- Vacuum Filtration
- Gypsum Stack Dewatering

2.6.1. Vacuum Filtration

A primary dewatering step would consist of a cluster of hydrocyclones, similar to the plant's existing limestone mill classifier (Figure 2-7). This cluster would be located adjacent to the mill classifier. Two tanks on the ground outside the building would receive the overflow and underflow from the hydrocyclones. The Filter Feed Tank would receive the large crystals (underflow). The Reclaim Water Tank would receive the fines, for return to the absorbers.

Figure 2-7 – Hydrocyclones for Primary Gypsum Dewatering

Secondary dewatering would be done in the vacuum filter. Vacuum filtration involves placing the thin slurry of mature gypsum from the Filter Feed Tank. The slurry is placed on the fabric and air is drawn through the fabric. The air carries water out of the solids, leaving a relatively dry filter cake on the fabric. The filter cake is moved to the storage pile on a belt conveyor. For this application, S&L recommends a simple vacuum drum filter (Figure 2-8), as this device can meet the requirements. The drum filter would be located inside a new enclosure on the roof above the mill classifier and the new hydrocyclones. A new second floor would be built above the existing Limestone Slurry Tank on half the bay that is open for mill hoisting. This floor would accommodate the vacuum filter pump/moisture separator and the filter blowback fan.

Figure 2-8 – Vacuum Drum Filter

Gypsum cake would be conveyed to a radial stacker, which would make the gypsum storage pile. Although gypsum leachate is not harmful, the storage pile would have an impermeable base, to avoid any controversy. As a sector of the pile reaches full height, it would be covered with tarpaulins, weighted with used tires, in similar fashion to the way road salt is stockpiled.

2.6.2. Gypsum Stacking

An alternative approach to gypsum dewatering would use the same primary dewatering step as the vacuum flitration approach. However, the secondary dewatering would be done at the storage pile. The impermeable base would be surrounded by a curb and gutter. At the end of the pile that will be inventoried last, the base would slope downward, ending in a sump. Gypsum from the hydrocyclone underflow tank would be pumped to a radial stackout pipe, creating a wet stack of gypsum. Water in the gypsum would decant and drain to the sump. Decant water would be pumped from the sump back to the absorbers.

As the gypsum stack reaches full height, the stacker pipe would move to its next position to make a new, adjacent stack. As the top of a completed stack dries, that stack can be covered with tarps and tires as described above.

Gypsum stacking is less common than vacuum filtration, but it can be seen in operation at two Ameren plants (Sioux and Labadie), not far from Sikeston. S&L expects the cost of dewatering by gypsum stacking to be similar to that of vacuum filtration with a drum filter.

Figure 2-9 – Dewatering by Gypsum Stacking

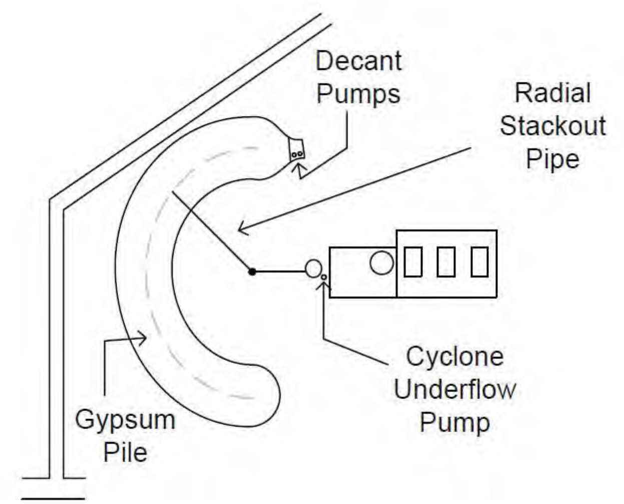
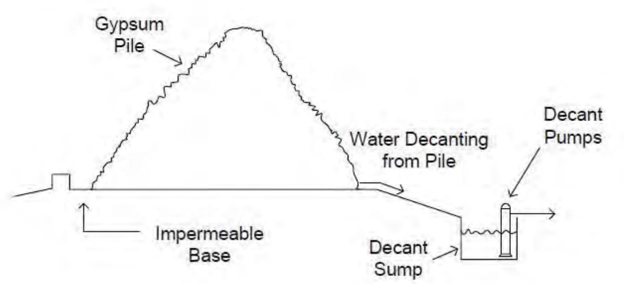


Figure 2-10 – Cross-Section of Gypsum Stack



The cost shown for gypsum dewatering are for the vacuum filtration option. S&L believes the cost of the gypsum stacking option will be similar, but slightly lower.

6. SUMMARY AND RECOMMENDATIONS

Sargent & Lundy performed the study to investigate several possible responses to the Cross-State Air Pollution Rule (CSAPR) and the Proposed Utility MACT rule. This involved tasks to determine the feasibility of re-starting the Sikeston Power Station FGD system, mothballed since 1998, as well as tasks to estimate the cost of replacing the existing FGD system with a new one, or avoiding SO_2 and mercury issues altogether by switching to burning gas at SPS.

6.1 RE-STARTING THE EXISTING FGD SYSTEM

Re-starting the existing FGD system would not consist of simply operating it in the same mode it did when it was last operated. The fuel has changed and the target emissions have changed since that time. Also, SPS personnel rightly anticipate that there will soon be new Federal rules placing severe constraints on operators of ponds such as that last used by the FGD system. Sargent & Lundy verified that the FGD system will operate favorably in the altered operating mode.

- The FGD system will achieve 95% removal of the SO_2 resulting from combustion of the PRB coal.
- The FGD system will produce a highly oxidized gypsum by-product, without the need for a forced oxidation system.
- The FGD system will create a slightly higher flue gas pressure drop, but not enough to require modification to the ID fans.

However, to accommodate the desire to produce by-product gypsum dewatered to less than 15% moisture for commercial sale, and long-term storage of the by-product, a new gypsum dewatering system would be required. This could be either a mechanical system using a vacuum drum filter, or it could be a gravity gypsum stacking system. S&L has estimated a cost for the vacuum filter system and believes the gypsum stacking system would have similar cost.

A second aspect of re-starting the FGD system is rehabilitation. S&L was pleasantly surprised by the condition in which the system was left. It reflects good operating practices when the system was operating as well as good practices when mothballing the system. S&L has performed a preliminary condition assessment to support our estimate of the cost for rehabilitation.

6.2 REPLACEMENT OF THE FGD SYSTEM WITH A NEW FGD SYSTEM

S&L prepared a factored estimate of the cost to replace the FGD system with a new one. This estimate is based on S&L's database of recent projects, adjusted for size, scope and escalation.

6.3 CONVERSION TO NATURAL GAS FIRING

Sargent & Lundy developed a cost estimate for conversion of SPS to natural gas firing. This estimate has two components. S&L estimated the cost of replacing the coal burners with natural gas burners. S&L located the nearest natural gas transmission line and estimated the cost to run a branch line to SPS. This is not a detailed estimate and has similar accuracy to the factored estimate for the new FGD system.

6.4 COST COMPARISON

The estimated costs are shown in Table 6-1. This shows that re-starting the existing mothballed FGD system is the most favorable option, by a wide margin.

Table 6-1 – Summary of the Cost Estimates for Alternatives

	Re-Start Existing FGD System	New FGD System	Convert to Natural Gas
Capital Cost	$22.2 million	$176 million	$52 million

Attachment C

Attachment C

Regional Haze Rule: States will be required to submit their Regional Haze State Implementation Plan (SIP) for the second regional haze planning period by July 31, 2021. As part of the next planning period, Missouri will be required to update its Long-Term Strategy and Reasonable Progress Goals (RPGs) to demonstrate that the State is meeting, or exceeding, the uniform rate of progress (i.e., reductions in visibility impairing air pollutants) that would lead to natural visibility conditions by 2064. The Regional Haze rule requires states to prepare an RPG four-factor analysis of emissions from existing sources, taking into consideration the costs of compliance, time necessary for compliance, energy and on-air quality environmental impacts and remaining useful life. Based on a review of RPG evaluations conducted in Texas and Arkansas as part of the initial planning period, it is possible that a four-factor RPG evaluation of SPS Unit 1 could conclude that additional SO2 emission reductions from SPS Unit 1 would be cost-effective and provide measurable visibility improvement at one or more Class I area. Potential SO2 reduction strategies would include DSI, re-starting the existing wet FGD, or installing a new dry or wet FGD control system. Because SPS Unit 1 is equipped with an existing, but non-functioning, wet FGD control system, re-starting the existing FGD could be identified as a cost-effective alternative. Based on cost estimates prepared by S&L in 2011, the order of magnitude cost of restarting the existing FGD system would be in the range of $25MM (2017 dollars).

Source: SL- Sikeston U1 RUL Study_R1_April -30-2020 Final Report.docx. Remaining Useful Life Study, prepared by Sargent & Lundy, 4/20/2020.

Attachment D

Attachment D

Although the existing wet FGD system is currently inoperative, SPS will have to meet the applicable standards if the FGD system is restarted or replaced, and FGD wastewaters are discharged through the facility's wastewater management system. FGD wastewater treatment costs were not included in the October 2011 FGD Re-Start Study, and could have a significant impact on the cost of restarting or replacing the existing wet FGD control system. The FGD wastewater ELG standards were based on advanced physical/chemical and biological treatment of the wastewater stream prior to discharge. Advanced wastewater treatment, including chemical precipitation, filtration, and anoxic/anaerobic biological treatment will likely be required to meet all applicable ELG standards. Advanced FGD wastewater treatment, including both physical/chemical and biological treatment, could add an order of magnitude cost of $35MM to the cost of a wet FGD control system. However, the extent of wastewater treatment required will be a function of the wastewater stream characteristics and the specific wastewater discharge and receiving stream limits, and must be evaluated on a case-by-case basis.

Source: SBMU Regulatory Review Report_R0.docx. Prepared by Sargent & Lundy, 5/12/2017.

C-6 Labadie Energy Center Four-Factor Analysis

Ameren MISSOURI

October 15, 2020

Ms. Darcy Bybee,
Director
Air Pollution Control Program
Missouri Department of Natural Resources
P.O. Box 176
Jefferson City, MO 65102

Re: Regional Haze Four-Factor Analysis – Information Collection Request
Ameren Missouri Labadie Energy Center
Facility ID: 071-0003

Dear Ms. Bybee:

Union Electric Company, d/b/a Ameren Missouri, herein responds to the subject Information Collection Request letter from MDNR dated July 29, 2020. In the letter, MDNR requested certain information required for the Missouri Department of Natural Resources' (MDNR) Regional Haze four-factor analysis for the Ameren Missouri Labadie Energy Center located at 226 Labadie Power Plant Road in Labadie, MO. Based on the letter, the four-factor analysis is required to evaluate technically feasible SO_2 and NOx control technologies for Boilers 1 through 4. This is required to be included as part of MDNR's development of a strategy for meeting reasonable progress goals for visibility impairment at Class 1 areas during the 2028 planning period.

The attached report contains information on cost estimations using the USEPA Air Pollution Control Cost Manual and Ameren site specific studies previously performed to determine the overall cost effectiveness of installing additional emission controls on Labadie's units. The coal fired steam electric generating units (EGUs) at the Labadie Energy Center utilize a variety of lower emitting processes that include the following technologies: ultra-low sulfur fuel, low NOx burners, overfire air (OFA) systems, and neural network optimization systems. These existing technologies minimize emissions and Ameren utilizes post combustion controls on these units to further control mercury, non-mercury metals and particulate matter. Because of the already low emission rates, the installation of additional post combustion controls would have negligible overall impact.

In accordance with the information collection request, evaluations of the four Regional Haze Rule factors, including costs, have been included for Wet Flue Gas Desulfurization (Wet FGD), Spray Dry Absorbers (SDA), Dry Sorbent Injection (DSI), Selective Catalytic Reduction (SCR), and Selective Non-Catalytic Reduction (SNCR) controls. That information is provided in the attached report. Qualitative assessments were performed for the other emission controls where quantitative evaluation methodologies from USEPA were unavailable.

Please feel free to contact Michael Hutcheson (mhutcheson@ameren.com) or myself (swhitworth@ameren.com), at your convenience if you have questions or if you need additional information.

Sincerely,

Steven C. Whitworth
Senior Director, Environmental Policy and Analysis

Attachment

Response to Missouri Department of Natural Resources
Regional Haze Four-Factor Analysis - Information Collection Request
Dated July 29, 2020
For the Labadie Energy Center

Ameren Missouri
Environmental Services
1901 Chouteau Ave.
St. Louis, MO

Ameren Regional Haze Response

Table of Contents

I. Introduction

Ameren is providing the following information in response to the Missouri Department of Natural Resources (MDNR) letter regarding Regional Haze Four Factor Analysis-Information Collection Request dated July 29, 2020. The MDNR letter requests data and information for an analysis of the potential SO_2 and NOx emission reduction strategies at the Labadie Energy Center coal fired steam electric generating units (EGUs). The information has been requested to facilitate MDNR's development of Missouri's Regional Haze Rule state implementation plan (SIP).

The Regional Haze rule requires states to develop a long term strategy for reducing emissions from sources impacting visibility at Class I areas with a goal of returning to natural visibility conditions by 2064. The Regional Haze Rule provides four factors for states to consider when developing its potential control strategy. All four of these factors are discussed in this response. Specifically, Ameren is providing the following information:

1. The cost of potential emission control strategies for Labadie Energy Center EGUs are detailed below as requested in the subject information collection request. In cases where detailed cost estimates for certain technologies were not available, a qualitative analysis of the feasibility and comparable cost of the technology are included.
2. The time required for the installation of the potential control strategies for the Labadie Energy Center EGUs is detailed below including the engineering, permitting, procurement and construction timelines. Also discussed is the impact on timing that would result from control requirements on multiple units and units at multiple facilities.
3. The remaining useful life of the Labadie Energy Center EGUs are discussed as outlined in Ameren's recently released 2020 Integrated Resource Plan.
4. The energy and non-air quality environmental impacts of potential control strategies are discussed where those costs or impacts are identifiable.

The cost analyses included in this response to the MDNR request for information are not detailed engineering evaluations of each potential control option. The analyses provided herein have been performed at the behest of MDNR and we emphasize that they represent first order estimates prepared without the detailed engineering required to establish actual budget cost estimates and control device effectiveness evaluations. The analyses do not reflect the final engineering basis for development of any of the identified controls. The estimates, however, have been conducted in accordance with MDNR's request using the techniques in USEPA Air Pollution Control Cost Manual (EPA/452/B-02-001) as described below and are rough order of magnitude estimates. Actual engineering design assumptions and resulting costs of the devices may differ from the assumptions made in the below analyses based on facts that exist at the time of decommissioning.

Additionally, based on a review of visibility modeling conducted using US EPA modeling platforms by the US EPA[1], the Midwest Ozone Group (MOG) and the Lake Area Director's Consortium (LADCO), visibility in Class I areas in the Midwest and eastern states will likely meet the required visibility glidepath goals during the 2028 planning horizon. Accordingly, as described more fully herein,

[1] US EPA Technical Support Document for EPA's Updated 2028 Regional Haze Modeling Page 25, Table 3-3: https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf

additional controls on the Labadie Energy Center units are not warranted based on modeling projections, the costs identified for additional controls, and the other relevant factors..

II. Labadie Site Description

a. Unit Information

Labadie Energy Center consists of four pulverized coal, dry bottom, tangentially fired boilers (B-1, B-2, B-3, and B-4) which began construction from 1966-1967 and achieved commercial operation from 1970 to 1973. Boilers 1 and 2 have the same design rating (6183 MMBtu/hr) and nameplate capacity (675 MW). Similarly, Boilers 3 and 4 have a design rating of 6107 MMBtu/hr and a nameplate capacity of 690MW.

Ameren has employed a combination of emission control strategies on the Labadie Energy Center EGUs to minimize emissions of regulated pollutants including add on controls, lower emitting processes and use of lower emission fuels. Emission controls on the four Labadie Energy Center EGUs include activated carbon injection and electrostatic precipitators (ESPs) for control of Mercury (Hg) and particulate matter (PM). These controls enable Ameren to meet the stringent maximum achievable control technology requirements for Hg and non-Hg metals (PM surrogate) of the Mercury and Air Toxics Standards Rule (MATS rule).

NOx emissions are controlled from Units 1 through 4 via a combination of low NOx burners (LNB), separated over-fire air (OFA) and neural network optimization. The neural network optimization system combined with the Low NOx burners and staged combustion from separated over-fire air systems optimizes the reductions possible from these combustion controls. Additional reductions are not possible via further optimization. Additional NOx reductions from adding additional over-fire air systems to further stage construction are believed to have limited benefit as a result of the significant amount of combustion staging already occurring. Through this combination of controls, Ameren has achieved industry leading NOx control levels in the absence of post combustion controls. Ameren consistently achieves NOx emission rates at the Labadie Energy Center EGUs under 0.10 lbs. NOx per million Btus of heat input without the significant added costs of employing selective catalytic reduction technology (SCR) or selective non-catalytic reduction technology (SNCR).

The control of sulfur oxides is accomplished at the Labadie Energy Center by combusting very low sulfur coals. Ameren currently combusts some of the lowest sulfur coals available on the market. Ameren has a fuel procurement strategy designed to sustainably maintain its supply of low sulfur coals while also minimizing the cost of those fuels. Additional reductions from the purchase of even lower sulfur coals are not expected to be available or sustainable on an ongoing basis.

The above control strategies all combine together to effectively control emissions from the boilers. Because of the already low emission rates at the Labadie EGUS additional emission controls will have a lower overall impact.

b. Remaining Useful Life

Ameren recently released its 2020 Integrated Resource Plan (IRP) with a commitment to transition its generation fleet to a cleaner and more diverse portfolio. The plan includes the addition of 3,100 megaWatts (MW) of wind and solar generation resources by 2030. The plan also includes the retirement of all Ameren coal fired generation by 2042 and the retirement of Meramec Energy Center in 2022 and the retirement of the two Sioux Energy Center EGUs in 2028. The retirement of the Labadie EGUs is also included in the 2020 IRP. Two Labadie units are scheduled for retirement in 2036 and two in 2042 as outlined in the 2020 IRP.

The remaining useful life of emission units is considered in two ways under Regional Haze guidance. Remaining useful life must be taken into account as it is impacted by the time required for the installation of controls on a unit and as it affects the cost effectiveness of the controls on a cost per ton of emission reduction basis. The planned retirement of emission units within the Regional Haze planning horizon can be taken into account by states when developing a Regional Haze state implementation plan (SIP). Units that will retire before the end of the planning horizon (2028) can avoid the analysis of all four factors.

Remaining useful life also affects the cost effectiveness of any installed controls. Cost effectiveness of a control is determined based on the capital costs and the annual operation and maintenance costs annualized for the life of the control device or the life of the emission unit whichever is less. The period of annualization is the difference between the date a control device can be constructed and the retirement date of an emission unit (or the control device whichever is less).

Impacting the amount of time for annualizing those costs is the time required for the installation of controls. This time includes the planning, engineering, and permitting time required along with the actual purchasing and construction of the control device. These processes can take many years in combination after the state implementation plan is finalized which may push the operation of any new control device to 2028 or beyond. The time for installation of the different control devices evaluated in this document have been taken into account based on the best information and belief.

The amount of additional time for the construction of a new emission control devices lowers the overall useful life of the added control equipment. While normally new control equipment may have 30 or more years of useful life, any added controls at Labadie would have a reduced lifespan because the retirement dates for the Labadie EGUs are less than 30 years away based on the 2020 IRP retirement date of 2036 for Units 3 and 4 and 2042 for Units 1 and 2. This reduced lifespan increases the annualized cost because the total capital investment cost is annualized over a lower number of years. Changes in the annualization period has a large effect on the cost per ton of emission reduction. Decreases in the annualization period decrease the cost effectiveness of the control device by increasing the cost per ton of emission reduction making the installation of the control less beneficial.

It should also be noted that the time for the construction of the emission controls estimated in this analysis assume that only controls at Rush Island Energy Center are required. Should emission controls be required at multiple energy centers, the time for construction would most likely be extended as multiple large construction projects at multiple facilities requires additional coordination for engineering services, construction services and equipment procurement. For this reason, the times for construction are underestimated should multiple facilities be impacted by the Regional Haze SIP and the cost estimates would thereby be underestimated as well.

c. Site Specific Conditions Affecting Installation of Controls

An additional factor to consider is the physical ability to add additional control devices to the units. When the Labadie site was designed, equipment was laid out to achieve the best operation while keeping a small footprint for the site. Over time, changes to the layout have been made to improve the effectiveness of controls and to meet new regulatory requirements such as the Coal Combustion Residuals rule. These changes include the construction of new ductwork and ESP boxes on Units 1 and 2 and the installation of the material handling equipment and wastewater equipment necessary to meet the requirements of dry ash handling contained in the CCR rule. These changes along with the already congested layout creates problems for designing the layout for new emission control devices which take up a large amount of space. Labadie especially has a very cramped equipment layout with little extra room to install new, unplanned equipment or buildings. If new equipment needs to be added, significant rework will need to be performed including changing the layout of the ductwork. Ductwork changes may necessitate the inclusion of booster fans as well as electrical supply upgrades needed for the auxiliary power supply.

III. USEPA Air Pollution Control Cost Manual

a. Equation Limitations

The USEPA Air Pollution Control Cost Manual[2] (the Manual) provides very rough order of magnitude estimates of the cost to install and operate air pollution controls at a site. Using the methods and cost equations in the manual can produce inaccurate results depending on the situation. The estimations being used are very much generalized and will not show the actual costs that Labadie would incur due to the installation of additional emission controls. The manual itself indicates that the rough order of magnitude estimates are only “nominally accurate to within +/- 30 percent”.

Error will also occur at higher rates for cost estimations where the sample size from the original studies that helped develop the Manual were small. Specifically, this can occur when estimating pricing for controls not normally placed on units of certain MW sizes or emission rates. The Manual specifically points out that dry flue gas desulfurization (FGD) systems typically are not installed on larger combustion units. Using generalized equations to estimate costs on installing control devices for non-normal situations will produce values that are not representative of actual site-specific costs or emission reductions that would be achieved. Ameren recommends that MDNR rely both on previous actual site-specific studies performed along with the values produced using the equations in the Manual.

There are also certain default cost values that appear in the example equations for Direct Annual Cost calculations that are not representative of actual costs Ameren would incur. Examples of these default costs are the costs to purchase a ton of limestone, the costs for electricity and make-up water, and the cost for waste disposal. These estimates utilize relevant unit cost data obtained from

[2] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

actual operation data or prior performed studies when available instead of the default values in the Manual.

In addition, part of its risk mitigation and regulatory planning processes, Ameren has over the years developed high-level capital cost estimates for some of these control strategies with respect to various regulatory proposals. These estimates have been included in this evaluation for comparison to the values estimated using the Manual. Such estimates, however, are not based on detailed engineering and do not include the allowance for funds used during construction (AFUDC) costs in the total capital costs to better align with the Control Cost Manual "overnight" estimation calculation method.

b. Chapter Revision

Another limitation with the cost estimations is that Section 5, Chapter 1 of the Manual on SO_2 and Acid Gas Controls is currently in draft form. A revision to Section 5, Chapter 1 of the Manual was proposed in July 2020 and is currently undergoing a public comment period. Even though the July 2020 proposal is still under review, this version was used to estimate the SO_2 control cost instead of the previous version published in December 1995. The use of the draft control cost manual was recommended by footnote 63 of the EPA document "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period." Because Section 5, Chapter 1 of the Manual is still in draft and subject to change, the basis for the SO_2 control technology estimates in the draft manual, including the assumptions and equations, may contain errors. Because they are not finalized and may contain errors, the use of the draft Section 5 as recommended by EPA guidance on Regional Haze SIP development may result in inaccurate estimations for control costs. In order to better justify these estimates, they have been compared to site specific engineering cost estimates developed for Ameren.

A noted concern with the draft Section 5 of the EPA Control Cost Manual is the Spry Dry Absorber (SDA) estimation procedure appears to be missing a retrofit factor in the equations for the total capital cost for larger units. A retrofit factor is used in estimates for other controls like wet flue gas desulfurization, selective catalytic reduction (SCR), etc. In the draft Section 5, USEPA has broken out the capital cost equations for the SDA depending on the unit size and USEPA includes a retrofit factor in the capital cost equations for SDA installation on smaller EGUs. The Manual recommends using a different equation if your unit size is greater than 600 MW. However, like the Manual indicates, installing Dry FGDs on larger units is uncommon. Creating equations to estimate prices for larger units will most likely have a higher chance of error because of limited example cases. Despite this concession by USEPA, one notable factor is absent in the cost estimation equation for large units. The cost equation for large units greater than 600 MW does not include a built-in retrofit factor when calculating Total Capital Investment even though the larger units will have the same if not greater retrofit issues that smaller units will have. Further along in the procedure a retrofit factor is included in the denominator for the calculation of annual maintenance costs. The inclusion of this factor in the denominator appears to assume that a retrofit factor was applied to the Total Capital Investment and needed to be removed to estimate the annual maintenance cost.

If the greater than 600 MW equation is used as it currently is written, the retrofit factor never gets applied to the Total Capital Investment. As stated in the Manual, retrofit factors are recommended for use in the cost estimations for sites requiring more difficult installations. Leaving the retrofit factor out of the equation for larger units appears to be an error in the draft Section 5 TCI equation for large

SDA installations. To correct for this error, Ameren has added in the retrofit multiplier to the SDA total capital cost for the greater than 600 MW equation from the Manual.

c. Retrofit Adjustments

The Manual allows for the use of retrofit adjustments for existing sites with conditions that lead to higher costs to retroactively install emission controls. Under the procedures in the Manual, higher retrofit factors are used for congested sites as costs can vary from site to site depending on the complexity of installing new equipment in an existing facility. As discussed in Section II, Labadie has a higher cost to fitting in additional controls because of limited space and the large amount of rework required for the ductwork and additional upgrades necessary to existing equipment that would need to occur to handle the operation of additional controls. These units were constructed 50 years ago, with little consideration to providing areas to accommodate future modification and plant additions. The site is constrained by the river on one side, the "close-coupled" coal pile, reclaim and receiving systems and coal rail loops, and switchyard operational area. Only one side of the plant is practical for retrofits. Much of that remaining space was taken up by the construction of the "C" precipitators in the early 1980's. Because of these high cost issues, the retrofit factor for Labadie has been increased to 1.5 for Wet FGD and SDA installations. These higher SO_2 retrofit factors are, in part, justified based on a comparison of the results of the capital cost estimates using the Manual and the capital cost estimates completed for Ameren's internal evaluations. The retrofit factor has been increased to 1.2 for SCR NOx control. The following list describes the reasons why space issues and construction costs will be higher than average at Labadie:

- Retrofits requiring very long runs of flue gas ductwork will be made high over existing equipment. At Labadie, the ductwork needed may reach 800 feet. The height will require extensive structural steel and foundations that meet current wind and seismic design loads. The cost of this structural work, including reinforcement of existing structures due to the new additional loads, will be significant.
- New controls would potentially require relocation of buildings and equipment. Some equipment, piping, and bus ducts are underground, adding significant cost.
- The electrical power requirements for new controls can be quite large and existing power sources in the plant are not adequate. Getting the required power directly from the switchyard adds significant costs.
- Some controls will add enough pressure resistance to the draft systems that will require the installation of new and/or booster fans. The installation of this equipment in areas with limited space will increase costs, along with the additional power needs to run the equipment.
- Scheduling of control equipment installation for multiple units and coordinating with other maintenance occurring during outages will be a challenge, especially given the limited number of craft labor available nationally to perform these installations. The control cost manual specifically asks for costs itemized in formulas to be considered without adding in significant cost adjustments for labor due to overtime or premium pricing for specialized technicians. The retrofit factor is used to account for these premium labor factors.

d. Inflation Adjustments

Values in the Manual have also been adjusted for inflation. The Manual provides a model with equations to estimate the cost of SO_2 and NOx controls based on 2016 dollars and have been adjusted for inflation for this evaluation. Section 1, Chapter 2 of the Manual under section 2.5.3 recommends adjusting for inflation only to the date that the cost estimate is prepared and not escalated to a future year. Ameren utilized a 2% per year inflation adjustment for the cost estimates in this document as recommended by USEPA in the Manual. All values have been adjusted to 2020 dollars.

IV. SO_2 Control Technologies

a. Feasible Options

While most of the listed control options in the MDNR data request letter are technically "feasible" for use on coal fired boilers, many of them are not normally used on larger sized boilers and would not be cost effective or control emissions efficiently. Units 1 through 4 at Labadie Energy Center currently combust western sub-bituminous low sulfur coals which already greatly reduces the SO_2 emission rate. Wet FGDs are the more common post combustion SO_2 control utilized on larger boilers like Units 1 through 4. Dry Sorbent Injection (DSI) systems have also been used for SO_2 controls, but it is less commonly used for larger boilers. Ameren has previously performed rough order of magnitude cost studies for both Wet FGDs and DSI installation and operation costs and those cost estimates are presented in the discussion below. The capital cost values have been altered from the study to remove out AFUDC costs as required by the Control Cost Manual to fit the “overnight” estimation method. The values have also been adjusted for inflation to 2020 dollars amounts.

b. Cost Calculations

Section 5, Chapter 1 of the USEPA Air Pollution Control Cost Manual was used to evaluate add on SO_2 control technologies at Labadie Energy Center for capital costs, annual operating and maintenance costs, and the annualized costs and the cost effectiveness for removing emissions. While the Manual mentions a few different available SO_2 control technologies, it only performs an extensive review with cost equations for Wet Limestone FGDs and Lime Spray Dry Absorbers. Ameren has used the equations in the Manual to perform cost estimations for the installation and operation of both technologies. These values are also compared to the cost estimates that Ameren has performed in the past for Wet FGD as well as costs for Dry Sorbent Injection (DSI) control systems.

While DSI costs are not detailed in the Manual, they are provided here for comparison to other SO_2 control technologies. It should be noted that the costs detailed in the Ameren studies are based on the average cost for installation of the same technology on each of the four (4) EGUs. Significant cost savings associated with engineering, procurement, project management, construction management are inherent in those estimates. Conversely, the capital costs for installation of these technologies on a single unit or pair of units are likely underestimated because of this. In other words, the annualized cost per ton of emission reduction for installing Wet FGD on just Unit 1 (or any single unit) is likely higher than shown in Table 3 because cost efficiencies assumed for multi-unit installations will not be possible. Tables 1 through 3 detail the evaluation of the cost of the SO_2 control technologies.

Table 1: SO_2 Estimated Emission Reductions

Control Equipment Type	Labadie Boilers	Baseline Emission Rate (lb/mmbtu)	Control Rate (lb/mmbtu)	Control Effectiveness (Percent Reduction)	Annual Emissions Reduction (tons/year)
Wet FGD	B1	0.44	0.05	89%	7,395
	B2	0.44	0.05	89%	7,395
	B3	0.44	0.05	89%	6,904
	B4	0.44	0.05	89%	6,904
SDA	B1	0.44	0.06	86%	7,205
	B2	0.44	0.06	86%	7,205
	B3	0.44	0.06	86%	6,727
	B4	0.44	0.06	86%	6,727

Table 2: SO_2 Estimated Control Costs using USEPA Air Pollution Control Cost Manual Equations

Control Equipment Type	Labadie Boilers	Capital Costs	Annual Operating and Maintenance Costs	Annualized Costs	Cost Effectiveness (cost/removed ton)
Wet FGD	B1	$445,565,100	$13,121,516	$59,702,814	$8,074
	B2	$445,565,100	$13,121,516	$59,702,814	$8,074
	B3	$446,087,333	$12,722,224	$83,261,587	$12,061
	B4	$446,087,333	$12,722,224	$83,261,587	$12,061
SDA	B1	$409,406,400	$11,173,764	$53,947,778	$7,487
	B2	$409,406,400	$11,173,764	$53,947,778	$7,487
	B3	$418,504,320	$10,869,315	$77,018,655	$11,450
	B4	$418,504,320	$10,869,315	$77,018,655	$11,450

Table 3: SO_2 Estimated Control Costs from Previous Ameren Studies

Control Equipment Type	Labadie Boilers	Capital Costs	Annual Operating and Maintenance Costs	Annualized Costs	Cost Effectiveness (cost/removed ton)
Wet FGD	B1	$447,660,000	$7,560,000	$54,241,589	$7,335
	B2	$447,660,000	$7,560,000	$54,241,589	$7,335
	B3	$447,660,000	$7,560,000	$78,229,404	$11,332
	B4	$447,660,000	$7,560,000	$78,229,404	$11,332
DSI	B1	$143,424,000	$21,963,200	$35,672,030	$6,069
	B2	$143,424,000	$21,963,200	$35,672,030	$6,069
	B3	$143,424,000	$21,963,200	$40,990,942	$7,470
	B4	$143,424,000	$21,963,200	$40,990,942	$7,470

As discussed above, Units 1 through 4 at the Labadie Energy Center burn very low sulfur coals as a control strategy to reduce SO_2 emissions. As shown in Table 1, the baseline SO_2 emission rates are already relatively low prior to the evaluation of additional post-combustion SO_2 controls. The potential reduction in SO_2 emissions resulting from adding post-combustion control devices, such as Wet Scrubbers (Wet FGD), SDAs, or DSI, is significantly lower for Units 1 through 4 when compared to similar coal fired emission units that do not burn low sulfur fuel. The lower potential for emission reductions results in higher costs of removal on a per ton of emission reduction basis.

Table 2 shows the estimated capital costs, annual operating and maintenance costs, and the annualized costs using the procedures in the Manual and the remaining useful life of the units from the 2020 IRP. Because Units 3 and 4 are scheduled for retirement in 2036 and Units 1 and 2 in 2042, the annualization period is different for the pairs of units. The earlier retirement of Units 3 and 4 results in higher annualized costs of removal than Units 1 and 2 which have the later retirement date. Per the procedures in the Manual, Wet Scrubbers and SDAs have an estimated control life of 30 years which is longer than the remaining life of the plant so the annualization period is based on the difference between the estimated date of operation for the control and the retirement date. Ameren has taken into account the time it takes for planning, engineering, permitting, purchasing, construction, installation and initialization of the controls and determined that for Wet Scrubbers and SDA, the estimated date of operation, assuming the Missouri state implementation plan is approved in 2023, would begin in 2028 for an annualization period of 8 years for Units 3 and 4 and 14 years for Units 1 and 2. For DSI controls, the estimated date of operation would begin in 2026 for an annualization period of 10 years for Units 3 and 4 and 16 years for Units 1 and 2.

Studies previously performed by Ameren on Wet Scrubbers show similar total capital cost amounts when compared to cost estimates using the equations in the Manual. While estimated calculations were performed for the SDA installation and operation based on the Manual equations, Ameren has not had site specific studies performed for SDA costs. This is mainly due to the fact, as stated in the Manual, that Dry FGD's are not a normal option for SO_2 emission reduction for units of Labadie's size. Nevertheless, the cost estimations still show that the cost for one ton of removal is relatively high for this scenario.

When using the Control Cost Manual equations, default values were updated to better estimate actual predicted costs for Labadie and the retrofit value was also increased to reflect the increased difficulty of the installation at the already congested site. While the capital cost is similar between the units, the annualized cost and cost to remove one ton of emissions is greatly affected by the remaining life of the units. However, in either case, Ameren believes the cost to remove one ton of SO_2 emissions with either an added on Wet FGD or SDA exceeds the reasonable cost of compliance which is one of the four factors in determining potential control measures for the State Implementation Plan.

While DSI calculations are not performed in the Control Cost Manual, Ameren had previously performed studies to determine the capital cost and annual operating costs of a DSI system at Labadie. For a DSI system to be installed at Labadie, a fabric filter most likely will be required to be installed to control PM emissions which increases the overall capital cost as seen in Table 3. DSI systems used as the main control measure for SO_2 are not normally installed on units of Labadie's size. The manual indicates that in 2018, only 17 power plants were using DSI to control SO_2 further indicating that this is not a common method for SO_2 removal. Even though the cost to remove one ton of emissions appear to be lower with DSI, the lower removal efficiency of SO_2 decreases the total overall tons of SO_2 removed which causes the addition of a DSI system to have a much lower impact on visible emissions.

c. Evaluations of FGD Technologies

Flue gas desulphurization technologies are generally classified as once-through or regenerative, and each of these can be further classified as wet or dry systems. Regenerative systems have higher capital costs than once-through systems because of the additional required process equipment to separate and dry the recovered salts. The vast majority of installed FGDs are once-through, and while most wet FGDs utilize limestone as the reagent, there are variations such as those below that are characterized by the reagents utilized. There are advantages and disadvantages of each technology, but in general the major equipment is very similar resulting in similar costs, and each technology can achieve high SO_2 removal rates. Detail studies of each technology would be required to determine the capital and operating costs for each specific unit application.

Section 5, Chapter 1 of the Manual includes cost equations for Wet Scrubbers using limestone as a reagent and SDAs with a lime reagent but does not include costs for other SO_2 control technologies. It does provide some relative cost information on other control technologies based on limited information on actual costs from plants that have installed the technology. The Manual indicates that Wet Scrubbers using lime have higher costs than limestone systems due to the higher purchase price cost of lime. The average controlled emission rate is also lower for limestone than lime-based systems as seen in Table 1.2 in Section 5 of the Manual. The higher operating costs and higher average controlled emission rates for lime systems indicates that the cost per ton of SO_2 reduction for a wet lime scrubber system would be higher than that of a limestone system.

The Manual does not include cost equations for Circulating Dry Scrubbers (CDS), however, it does indicate that the capital costs for a CDS system are similar to the SDA system for combustion units of the same size and emission rates. Table 1.2 in Section 5 of the Manual also indicates that the average emission rates for units with SDAs are lower than units with CDS installed. If units with SDAs have lower emission rates, but similar pricing, CDS cost to remove one ton of emissions would be higher than SDAs, making the evaluation of CDS costs unnecessary.

Magnesium Enhanced Lime (MEL) FGDs and Dual Alkali FGDs are both wet FGD systems. The absorber equipment may be smaller than a limestone Wet FGD, but the sorbent cost is significantly higher, making these control technologies not commonly used in the power industry. Table 1.1 in Section 5 of the Manual indicates that in 2018 only 4 Dual Alkali systems were installed at U.S. Power Plants. Dual Alkali systems also show similar SO_2 emission rates when compared to limestone FGD systems as shown in Table 1.2 in Section 5 of the Manual.

d. Evaluations of Other Technologies

Integrated Gasification Combined-Cycle (IGCC) is a very high capital cost technology and retrofitting an existing coal plant of Labadie's size would be very challenging and not economical. While theoretically, some systems like coal handling, water treatment, and steam turbines could be reused, they are spread out drastically over a large area as compared to a "green field" IGCC site making connecting these systems difficult. Trying to incorporate existing equipment could detrimentally influence the design and cost. The gasification plant, gas turbines, and heat recovery steam generators would require new locations on an already very congested site likely being very remote from the existing boiler building, again resulting in long runs of process lines between components. U.S. experience with reliability of the coal gasification process has not been good, and back-up natural gas for this technology would be very costly. We are currently not aware of an IGCC retrofit for an existing coal plant of Labadie's size.

Hydrated Ash Reinjection, Fuel Switching, and Coal Cleaning are also not optimal SO_2 control technologies for Labadie Units. Hydrated Ash Reinjection involves the improvement of lime sorbent utilization by the recirculation of the boiler's ash. This technology is more applicable for fluidized bed boilers, not pulverized coal boilers where there is no lime usage. Labadie is already burning 100% Power River Basin (PRB) coal, some of the lowest sulfur coals in the country. In addition, these units are typically burning coal from the individual mines and seams with some of the lowest sulfur contents within the PRB. Fuel switching is not reasonable because of the already low sulfur fuel being combusted. Coal cleaning is also more effective for coals where much of the sulfur is inorganic pyrite. Most of the sulfur in PRB coals are part of an organic compound and are less affected by coal cleaning. Because of the already low sulfur content of the coal and organic type of sulfur in the coal, coal cleaning to remove additional sulfur would be less effective and the costs unjustifiable when compared to sites using higher sulfur content coal.

V. NOx Control Technologies

a. Existing NOx Controls

As discussed above, Ameren minimizes NOx emissions at Units 1 through 4 at the Labadie Energy Center using a combination of low NOx burners, separated overfire air and neural network optimization. These technologies operate continuously while the boilers are in operation to prevent NOx from being generated in the combustion process. The LNB and OFA systems combine to delay the mixing of air and fuel to reduce and prevent the formation of thermal NOx and to complete fuel combustion in a lower temperature portion of the furnace to further reduce NOx emissions. These systems combined with an artificial intelligence neural network that learns and adjusts operational settings to optimize combustion (i.e., produce the lowest NOx emissions in the safest manner), along with burning 100% western sub-bituminous coal (lower nitrogen content to reduce fuel related NOx) have made these units some of the lowest NOx emitting coal-fired boilers in the country. Additional reductions in NOx from this combination of technologies is not believed to be achievable. Units 1 through 4 operate at an already optimized emission rate of 0.09 lb NOx/mmbtu based on 2017-2019 emissions data. Considering the uncontrolled NOx emission rate for tangentially fired boilers from AP-42 Table 1.1-2 is 8.4 lb/ton, and a subbituminous coal heat content of 17.5 mmbtu/ton, the uncontrolled NOx emission rate of the boilers would be 0.48 lb NOx/mmbtu. With existing LNB and OFA controls, Labadie already achieves 81% NOx control, among the lowest emission rates for coal-fired plants with no post-combustion controls.

b. Feasible Options

Both Selective Catalytic Reduction (SCR) systems and Selective Non-catalytic Reduction (SNCR) systems are feasible technologies for the Unit 1 through 4 EGUs at the Labadie Energy Center because they have been installed and operated successfully at other coal-fired EGUs. Similarly, flue gas recirculation (FGR) and low excess air are also feasible technologies, however, the current use of low

NOx burners and separated overfire air are similar technologies as FGR and low excess air and are believed to be both incompatible with and less effective than the existing technologies used to minimize NOx from Units 1 through 4.

c. Cost Calculations

SCR and SNCR technologies were evaluated following the methods of EPA's Air Pollution Control Cost Manual, Section 4, Chapters 1 and 2.

The evaluation of SCR controls following the procedures in the Manual uses a combination of plant-specific operation characteristics and default choices to estimate the potential reduction in annual NOx emissions, the total capital cost of construction, and the annualized cost of operation for the control. The SCR calculation includes the choice of outlet NOx emission rate. For the calculations below, the outlet NOx rate of 0.04 lb/mmBTU is chosen based on the cost manual Chapter 2, section 2.3.5, indicating that the NOx outlet should not be set less than 0.04 lb/mmBTU without a vendor guarantee. Since this analysis did not obtain specific vendor information, outlet NOx rates below this level are inappropriate.

Plant specific inputs are used in the SCR control cost tool, to fill in missing data or in place of defaults for the following tool inputs:

- Boiler MW rating at full load capacity
- Estimated actual megawatt hours output
- Net plant heat input rate in mmBtu/MW
- Sulfur content of fuel
- Number of days the SCR operates
- Number of days the boiler operates
- Inlet NOx in lbs/mmBtu
- Outlet NOx in lbs/mmBtu
- Number of chambers
- Number of catalyst layers
- Number of empty catalyst layers
- Gas temperature at inlet
- Estimated equipment life in years

Table 4 resulting emission reductions are regardless of reagent chosen, either ammonia or urea. Table 5 resulting cost effectiveness estimates vary based on the reagent chosen.

Table 4: NOx Estimated Emission Reductions using EPA Air Pollution Control Cost Manual Equation

Labadie Boilers	Control Equipment Type	Baseline Emission Rate (lb/mmBtu)	Control Rate (lb/mmBtu)	Control Effectiveness (Percent Reduction)	Annual Emissions Reduction (tons/year)
B1	SCR	0.09	0.04	56%	998
B2	SCR	0.09	0.04	56%	998
B3	SCR	0.09	0.04	56%	964
B4	SCR	0.09	0.04	56%	964

Table 5: NOx Estimated Control Costs using EPA Air Pollution Control Cost Manual Equation

Labadie Boilers	Control Equipment Type	Capital Costs	Annual Operating and Maintenance Costs	Annualized Costs	Cost Effectiveness (cost/removed ton)
B1	SCR - Ammonia	$214,663,839	$3,082,522	$23,619,764	$23,673
B2	SCR - Ammonia	$214,663,839	$3,082,522	$23,619,764	$23,673
B3	SCR - Ammonia	$218,834,320	$3,071,767	$32,126,553	$33,326
B4	SCR - Ammonia	$218,834,320	$3,071,767	$32,126,553	$33,326
Labadie Boilers	Control Equipment Type	Capital Costs	Annual Operating and Maintenance Costs	Annualized Costs	Cost Effectiveness (cost/removed ton)
B1	SCR- Urea	$214,663,839	$3,146,983	$23,684,224	$23,738
B2	SCR- Urea	$214,663,839	$3,146,983	$23,684,224	$23,738
B3	SCR- Urea	$218,834,320	$3,134,048	$32,188,833	$33,391
B4	SCR- Urea	$218,834,320	$3,134,048	$32,188,833	$33,391

The evaluation of SNCR controls according to the manual is not possible since page 1-41 states that "… the cost equations are sufficient for NOxout emission levels as low as 0.08 lb/mmBtu for FB and 0.1 lb/mmBtu for non-FB." Units 1 through 4 are not FB, or fluidized bed, boilers so the equations in the manual are only sufficient for outlet NOx rates down to 0.1 lb/mmBtu. Labadie currently emits at 0.09 lb/mmBtu, less than the 0.1 outlet concentration rate that the cost equation can estimate. From the Manual Section 4, Chapter 1, Figure 1.1c, SNCR NOx Reduction Efficiency Versus Baseline NOx Levels for Coal-Fired Utility Boilers, at inlet NOx concentrations below 0.2 lb/mmBtu, there are no datapoints from which to estimate NOx reduction efficiency. Extrapolating from the regression line, emission reductions of less than 20% may be expected for inlet NOx near 0.09 lb/mmBtu. With the period 2017-2019 averaging approximately 7,000 tons of NOx per year, the largest NOx reduction that could be expected is 1,400 tons per year with SNCR, with a more reasonable expectation of 1,050 tons per year based on 15% control efficiency.

To estimate the annualized cost in a methodology similar to the COST manual, the total capital cost of installing SNCR is estimated first, then the total capital costs are spread over the years of operation to estimate annual capital cost. Then the COST manual estimate of 25% capital cost and 75% operating costs are used to estimate total annual costs. The total annualized costs are then divided by the tonnage reduced to estimate cost effectiveness of SNCR.

The COST manual cites a NESCAUM study from March 7, 2005 on BART controls (http://www.nescaum.org/topics/regional-haze/regional-haze-documents) for an approximate utility capital cost of SNCR at $10 to $20 per kw. Costs are increased from 2005 dollars to 2020 by increasing 2% per year for 15 years, consistent with other cost estimates in this document. The total capital cost per unit is then divided over the remaining lifetime of each unit, and facility total annual capital cost is estimated at $4,336,313 in Table 6. The COST manual SNCR chapter states “A typical breakdown of annual costs for utilities is 25% for capital recovery and 75% for operating expense." With annual capital costs of $4,336,313, operating costs should be around $13,008,938, and total annual costs (capital recovery and operating) of $17,345,250.

Table 6: SNCR Cost Estimate

Capital Cost Range Singe Unit	Base Load (MW)	Base Load (kw)	Total Capital Cost per unit: Estimated $15 per kw	
			2005 dollars	2020 dollars
B1	675MW	675,000 kw	$10,125,000	$13,162,500
B2	675 MW	675,000 kw	$10,125,000	$13,162,500
B3	690 MW	690,000 kw	$10,350,000	$13,455,000
B4	690 MW	690,000 kw	$10,350,000	$13,455,000
Unit Name	Remaining Lifetime after Construction	Annual Capital Cost in 2020 Dollars	Annual Operating Cost in 2020 Dollars	Annual Total Cost
B1	16 years	$822,656	-	-
B2		$822,656		
B3	10 years	$1,345,500		
B4		$1,345,500		
Plant Total		$4,336,313	$13,008,938	$17,345,250

With annualized total cost estimated over $17 million at Labadie for SNCR that achieves 15% control efficiency and 1,050 tons of NOx reduced annually, the cost effectiveness estimated over $16,000/ton. SNCR is not a cost-effective option at Labadie due to already low NOx rates, little possible additional emission reductions, and capital cost recovery timeframes of only 10 to 16 years with established unit lifetimes.

d. Evaluations of Other Technologies

Low excess air technology is premised on lowering the amount of air (and its inherent nitrogen content) used for the combustion of coal in the furnace. As mentioned above, these units are already being operated at the lowest possible amount of air to safely and completely combust all of the coal.

Flue gas recirculation technology separates a small amount of flue gas from the boiler, typically from the boiler exit, and recirculates the flue gas back into the furnace to lower the flame temperature. This is a common technology on smaller gas and oil-fired units where duct runs are shorter, however, it is of limited value for larger coal fired EGUs. As mentioned above, these units already have significant staging of the combustion process resulting in a significant reduction of combustion temperatures. We are currently not aware of any large pulverized coal units utilizing this technology.

VI. Additional Impacts to Implementing New Controls

a. Air Quality Permitting

Permitting a new control device will require a construction permit from the Missouri DNR Air Pollution Control Program. Construction permits are charged a flat fee based on type, between $250 and $5,000, and an hourly rate of $75. A rough estimate of 100 hours for a permit leads to a permit cost above $7,500. The time to obtain the necessary permits is likely 12 months, adding to the time to implement the controls.

The COST manual introduction chapter describes the basic methodology for cost estimates, placing the permitting costs under indirect costs. Indirect costs are those borne by the facility even if the control equipment is not in continuous operation. Permitting costs are considered indirect costs, like property taxes, insurance, and administrative charges. However, the methodology outlined in the introduction and specific control chapters do not explicitly include permitting costs directly, either as a separate item or item included in the general percentage factor added to the total administrative cost. When an approximate one-time permitting cost of $7,500 is added to the administrative costs, the total cost effectiveness changes by less than $3/ton which is negligible. A more pressing concern is any time above 12 months to obtain a permit, which would decrease the lifetime of the control by a year. Changing the lifetime of controls can change cost effectiveness by $500/ton or more, so the permit issuance timing should be considered a more significant factor in overall cost effectiveness.

b. Waste Impacts

NOx controls typically do not significantly alter the characteristics of the fly ash, other than the deposition of ammonia sulfates in the fly ash. Ammonia content greater than 5 ppm can result in off-gassing, which would impact the salability of the ash as a byproduct, and excess ammonia will also impact the storage and disposal of the ash by landfill. SCR catalysts are not typically considered a hazardous waste once they can no longer be recycled or reused and can be disposed of in an approved landfill.

Wet FGD systems allow the recovery of salts in the form of gypsum, which can be sold as a byproduct or landfilled. Dry scrubber systems generally consume less water and require less waste processing, however, the waste generated from a dry scrubber contains metals and is considered hazardous waste. The generation of hazardous waste comes with significant costs to ship the waste offsite and disposal costs in an approved landfill.

c. Water Impacts

For NOx controls, the deposition of ammonia salts on the catalyst may require additional acid washing to remove deposits, if air and steam blowing are not sufficient to prevent buildup. Excess wastewater generated from acid washing must be disposed of and treated by the plant.

Dry FGD systems require additional water that is sprayed into the absorber to cool the flue gas to the proper temperature for chemical reaction. Wet FGD systems require additional water that is mixed with the alkali reagent to form the sorbent that is injected in the flue gas stream. Either wet or dry desulfurization systems will have additional water needs compared to existing plant controls. The processing of gypsum from a wet FGD system requires the waste slurry collected in the absorber to be filtered and then dewatered before being sent off site. The slurry wastewater treatment also includes the increase in pH to precipitate metals and potential additives to promote coagulation and flocculation.

d. Risk Management Plans

The Clean Air Act Section 112(r) requires risk management plans for facilities that use extremely hazardous substances. These plans are site-specific and must be revised and resubmitted to EPA every 5 years. For either SCR or SNCR that uses ammonia as the reagent, the cost manual recommends onsite storage concentration of 29%, above the RMP threshold of 20% concentration. The onsite storage of ammonia at 14 days or more is also over the 20,000 lb regulated substance RMP threshold. Formulating the plan, onsite monitoring and reporting, and minimum annual coordination with local emergency planning and response agencies represent significant administrative costs that the cost manual does not attempt to estimate or include.

Based on past plans of similar complexity created by Ameren, an estimate of plan initial design will take a total of 165 hours of engineering, reviews and administrative work, for a total of $19,250. A single year of annual monitoring, reporting, and meetings with emergency management personnel will take 218 hours for a total of $27,250. These costs are not included in the estimates above and they increase the cost effectiveness totals by less than $10/ton.

VII. Conclusion

The cost estimates and evaluations developed in this response are based from either the USEPA Air Pollution Control Cost Manual or previous studies performed by Ameren. The Manual states that equations may have up to 30% error and some of the studies performed by Ameren are many years old so actual costs may be higher or lower than the current estimates. Calculations were performed for Wet FGD, SDA, SCR and SNCR installations and operation using information from the Manual. Cost estimates were also provided for Wet FGD and DSI additions using previous Ameren order of magnitude studies. The cost estimates show the high cost of adding post combustion control technology to Units 1 through 4 at the Labadie Energy Center based on USEPAs methodology and supported by Ameren’s order of magnitude engineering cost estimates.

The estimated cost per ton of emission reduction for post combustion SO_2 controls ranges from $6,000 per ton for DSI on Units 1 and 2 to $12,000 per ton for wet FGD on Units 3 and 4. The estimated cost per ton of emission reduction for post combustion NOx controls are even higher and range from $23,000 to $33,000 per ton of NOx reduction. These costs are higher than previously determined to be cost effective.

Importantly, US EPA modeling platforms indicate that the glidepath for the Midwest and Eastern states are likely to achieve both the 2028 planning goals without the need for additional controls as well as the Regional Haze Rule Goals of obtaining natural visibility conditions by 2064. Also, the reduction in emissions from the addition of emission controls at Ameren are unlikely to have a noticeable change in visibility which is the overall purpose of the Regional Haze Rule. Because of the unreasonably high emission removal cost and EPA modeled compliance projection by 2064, Ameren recommends that the Regional Haze Rule state implementation plan (SIP) for Missouri indicate that the cost for additional emission controls at Labadie is too high and unnecessary for natural visibility conditions to be met by 2064.

Attachment I: SO_2 Calculation Spreadsheets

Ameren Wet FGD Calculations

Labadie Wet FGD

Inputs	Source	B1	B2	B3	B4	
Full Load Capacity (MW)	nameplate	675	675	690	690	
Net Plant Heat input rate (MMBtu/MW)	design rate/max load with 5% reduction	9.64	9.64	9.32	9.32	
Max heat input rate (Mmbtu/hr)	design rate	6183	6183	6107	6107	
Max annual MW Output	Calc: MW nameplate *8760	5,913,000	5,913,000	6,044,400	6,044,400	
Est annual MW Output	Estimated from averaged past air markets data	4,140,000	4,140,000	4,000,000	4,000,000	
Est time control operates	Estimate from past air markets data	7,712	7,517	7,226	7,864	
Est time boiler operates	Estimate from past air markets data	7,712	7,517	7,226	7,864	
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.700	0.700	0.662	0.662	
SO2 baseline lb/mmbtu	Estimated from averaged past air markets data	0.44	0.44	0.44	0.44	
SO2 Outlet lb/mmbtu	Estimated after control added	0.05	0.05	0.05	0.05	
SO2 Removal Efficiency	Calc (SO2in-SO2out)/SO2 in	89%	89%	89%	89%	
SO2 Removed per Hour (lb/hr)	Calc (SO2in * Effic * Max annual heat input rate)	2411	2411	2382	2382	
Total SO2 Removed per year (tons)	Calc: SO2 per hr removed * Time control operates/2000	7395	7395	6904	6904	
Retrofit Factor		1.50	1.50	1.50	1.50	
Remaining Equipment Life	Based on Construction Time and Remaining Life of Unit	14	14	8	8	
Number of Additional Personnel	Default from Manual	16	16	16	16	
Hourly Labor Rate	Default from Manual	60	60	60	60	
Limestone Cost ($/ton)	Updated based on Ameren specific data	60	60	60	60	
Make-up water cost ($/gallon)	Updated based on Ameren specific data	0.0063	0.0063	0.0063	0.0063	
Waste Disposal ($/ton)	Default from Manual	30	30	30	30	
Electricity Cost ($/kwh)	Default from Manual	0.0361	0.0361	0.0361	0.0361	
Assumed Interest Rate	Default from Manual (NOx and SO2 sections were different. Using NOx value since SO2 section is still in draft)	5.5%	5.5%	5.5%	5.5%	
	Capital Cost (2016 $)	$ 412,560,278	$ 412,560,278	$ 413,043,826	$ 413,043,826	
	Direct Annual Cost (2016 $)	$ 12,149,551	$ 12,149,551	$ 11,779,837	$ 11,779,837	
	Annualized Cost (2016 $)	$ 55,280,383	$ 55,280,383	$ 77,094,062	$ 77,094,062	**Total**
	Captial Cost (2020 $)	$ 445,565,100	$ 445,565,100	$ 446,087,333	$ 446,087,333	**$ 1,783,304,865**
	Direct Annual Cost (2020 $)	$ 13,121,516	$ 13,121,516	$ 12,722,224	$ 12,722,224	**$ 51,687,480**
	Annualized Cost (2020 $)	$ 59,702,814	$ 59,702,814	$ 83,261,587	$ 83,261,587	**$ 285,928,802**
	Cost Effectiveness (2020 $/ton)	$ 8,074	$ 8,074	$ 12,061	$ 12,061	

Ameren Study Cost Estimations	B1	B2	B3	B4	Total
Captial Cost (2020 $)	$ 447,660,000	$ 447,660,000	$ 447,660,000	$ 447,660,000	**$ 1,790,640,000**
Direct Annual Cost (2020 $)	$ 7,560,000	$ 7,560,000	$ 7,560,000	$ 7,560,000	**$ 30,240,000**
Annualized Cost (2020 $)	$ 54,241,589	$ 54,241,589	$ 78,229,404	$ 78,229,404	**$ 264,941,985**
Cost Effectiveness (2020 $/ton)	$ 7,335	$ 7,335	$ 11,332	$ 11,332	

Ameren SDA Calculations

Labadie SDA >600MW

Inputs	Source	B1	B2	B3	B4	
Full Load Capacity (MW)	nameplate	675	675	690	690	
Net Plant Heat input rate (MMBtu/MW)	design rate/max load with 5% reduction	9.64	9.64	9.32	9.32	
Max heat input rate (Mmbtu/hr)	design rate	6183	6183	6107	6107	
Max annual MW Output	Calc: MW nameplate *8760	5,913,000	5,913,000	6,044,400	6,044,400	
Est annual MW Output	Estimated from averaged past air markets data	4,140,000	4,140,000	4,000,000	4,000,000	
Est time control operates	Estimate from past air markets data	7,712	7,517	7,226	7,864	
Est time boiler operates	Estimate from past air markets data	7,712	7,517	7,226	7,864	
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.700	0.700	0.662	0.662	
SO2 baseline lb/mmbtu	Estimated from averaged past air markets data	0.44	0.44	0.44	0.44	
SO2 Outlet lb/mmbtu	Estimated after control added	0.06	0.06	0.06	0.06	
SO2 Removal Efficiency	Calc (SO2in-SO2out)/SO2 in	86%	86%	86%	86%	
SO2 Removed per Hour (lb/hr)	Calc (SO2in * Effic * Max annual heat input rate)	2350	2350	2321	2321	
Total SO2 Removed per year (tons)	Calc: SO2 per hr removed * Time control operates/2000	7205	7205	6727	6727	
Retrofit Factor		1.50	1.50	1.50	1.50	
Remaining Equipment Life	Based on Construction Time and Remaining Life of Unit	14	14	8	8	
Number of Additional Personnel	Default from Manual	8	8	8	8	
Hourly Labor Rate	Default from Manual	60	60	60	60	
Lime Cost ($/ton)	Default from Manual	125	125	125	125	
Make-up water cost ($/gallon)	Updated based on Ameren specific data	0.0063	0.0063	0.0063	0.0063	
Waste Disposal ($/ton)	Default from Manual	30	30	30	30	
Electricity Cost ($/kwh)	Default from Manual	0.0361	0.0361	0.0361	0.0361	
Assumed Interest Rate	Default from Manual (NOx and SO2 sections were different. Using NOx value since SO2 section is still in draft)	5.5%	5.5%	5.5%	5.5%	
	Capital Cost (2016 $)	$ 379,080,000	$ 379,080,000	$ 387,504,000	$ 387,504,000	
	Direct Annual Cost (2016 $)	$ 10,346,077	$ 10,346,077	$ 10,064,181	$ 10,064,181	
	Annualized Cost (2016 $)	$ 49,951,646	$ 49,951,646	$ 71,313,569	$ 71,313,569	**Total**
	Captial Cost (2020 $)	$ 409,406,400	$ 409,406,400	$ 418,504,320	$ 418,504,320	**$ 1,655,821,440**
	Direct Annual Cost (2020 $)	$ 11,173,764	$ 11,173,764	$ 10,869,315	$ 10,869,315	**$ 44,086,158**
	Annualized Cost (2020 $)	$ 53,947,778	$ 53,947,778	$ 77,018,655	$ 77,018,655	**$ 261,932,865**
	Cost Effectiveness (2020 $/ton)	$ 7,487	$ 7,487	$ 11,450	$ 11,450	

Ameren DSI Calculations

With Fabric Filter

Labadie

assumed 70% removal efficiency

Inputs	Source	B1	B2	B3	B4	
Full Load Capacity (MW)	nameplate	675	675	690	690	
Max heat input rate (Mmbtu/hr)	design rate	6183	6183	6107	6107	
Max annual MW Output	Calc: MW nameplate *8760	5,913,000	5,913,000	6,044,400	6,044,400	
Est annual MW Output	Estimated from averaged past air markets data	4,140,000	4,140,000	4,000,000	4,000,000	
Est time control operates	Estimate from past air markets data	7,712	7,517	7,226	7,864	
Est time boiler operates	Estimate from past air markets data	7,712	7,517	7,226	7,864	
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.700	0.700	0.662	0.662	
SO2 baseline lb/mmbtu	Estimated from averaged past air markets data	0.44	0.44	0.44	0.44	
SO2 Outlet lb/mmbtu	Estimated after control added	0.13	0.13	0.13	0.13	
SO2 Removal Efficiency		70%	70%	70%	70%	
Assumed Interest Rate	Default from Manual (using NOx section interest rate)	5.5%	5.5%	5.5%	5.5%	
Remaining Equipment Life	Based on Construction Time and Remaining Life of Unit	16	16	10	10	
Capital Recovery Factor		0.0956	0.0956	0.1327	0.1327	
SO2 Removed per Hour (lb/hr)	Calc (SO2in * Effic * Max annual heat input rate)	1917	1917	1893	1893	
Total SO2 Removed per year (tons)	Calc: SO2 per hr removed * Time control operates/2000	5878	5878	5487	5487	**Total**
	Captial Cost (2020 $)	$ 143,424,000	$ 143,424,000	$ 143,424,000	$ 143,424,000	**$ 573,696,000**
	Direct Annual Cost (2020 $)	21,963,200	21,963,200	21,963,200	21,963,200	**$ 87,852,800**
	Annualized Cost (2020 $)	$ 35,672,030	$ 35,672,030	$ 40,990,942	$ 40,990,942	**$ 153,325,944**
	Cost Effectiveness (2020 $/ton)	$ 6,069	$ 6,069	$ 7,470	$ 7,470	

Attachment II: NOx Calculation Spreadsheets

Ameren SCR Calculations

SCR Urea		Labadie Snapshot SCR				
Inputs	**Source**	**B1**	**B2**	**B3**	**B4**	
Full Load Capacity (MW)	Capacity	675	675	690	690	
Net Plant Heat input rate (MMBtu/MW)	design rate/max load with 5% reduction 2016-2019	9.64	9.64	9.64	9.64	
Max heat input rate (Mmbtu/hr)	design rate	6183	6183	6183	6183	
Max annual MW Output	Calc: MW baseplate *8760	5,913,000	5,913,000	6,044,400	6,044,400	
Est annual MW Output	Estimate from past, avg of all units 2016-2019	4,140,000	4,140,000	4,000,000	4,000,000	
Est time control operates	Estimate	7,712	7,517	7,226	7,864	
Est time boiler operates	Estimate	7,712	7,517	7,226	7,864	
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.700	0.700	0.662	0.662	
Reagent	Urea	-	-	-	-	
Nox Inlet lb/mmbtu	From actuals achieved with LNB/OFA	0.09	0.09	0.09	0.09	
Nox Outlet lb/mmbtu	Goal number - COST manual says outlet SCR is rarely below 0.04 per their review of CAMD data	0.04	0.04	0.04	0.04	
Nox Removal Efficiency	Calc (Noxin-Noxout)/Nox in	56%	56%	56%	56%	
Nox Removed per Hour (lb/hr)	Calc (Noxin * Effic * Max annual heat input rate)	325.35	325.35	209.02	332.58	
Total Nox Removed per year (tons)	Calc: Nox per hr removed * Time SCR operates/2000	997.74	997.74	964.00	964.00	**Urea Total**
Capital Cost (to build it, 2016 dollars)	From Tool, all defaults	$ 198,762,813	$ 198,762,813	$ 202,624,370	$ 202,624,370	**$ 802,774,367**
Annual Cost (operate and capital recovery, 2016	From Tool, all defaults, includes divided capital cost over years of operation	$ 21,929,837	$ 21,929,837	$ 29,804,475	$ 29,804,475	**$ 103,468,624**
Cost Effectiveness ($/ton, 2016 dollars)	Calc: Annual Cost by tons reduced	$ 21,979.51	$ 21,979.51	$ 30,917.51	$ 30,917.51	**$ 26,371.65**
Capital Cost (to build it, 2020 dollars)	Increase by 2% per year from 2016, 4 years total, 8%	$ 214,663,839	$ 214,663,839	$ 218,834,320	$ 218,834,320	**$ 866,996,316**
Annual O&M (one year operation, w/o capital	Increase by 2% per year from 2016, 4 years total, 8%	$ 3,146,983	$ 3,146,983	$ 3,134,048	$ 3,134,048	**$ 12,562,060**
Annualized Cost (operate and capital recovery, 2020	Increase by 2% per year from 2016, 4 years total, 8%	$ 23,684,224	$ 23,684,224	$ 32,188,833	$ 32,188,833	**$ 111,746,114**
Cost Effectiveness ($/ton, 2020 dollars)	Increase by 2% per year from 2016, 4 years total, 8%	$ 23,738	$ 23,738	$ 33,391	$ 33,391	**$ 28,481.38**

Labadie SCR B1 & B2 All Inputs		Source
Retrofit Factor	1.2	increased from default of 1.0
MW Rating at full load capacity	675	Plant specific
HHV of fuel	8826	default
Estimated acutal MWhs output	4,140,000	Plant specific
Net Plant Heat input rate (mmbtu/MW)	9.64	Plant specific
Sulfur content of fuel	0.19	Plant specific
Number of days SCR operates	321	Plant specific
Number of days boiler operates	321	Plant specific
Inlet Nox	0.09	Plant specific
Outlet Nox	0.04	Choice
Stoichiometric Ratio Factor	0.525	default 0.525 Urea, 1.05 ammonia
Number of Chambers	1	
Number of catalyst layers	2	
Number of empty layers	1	
Ammonia slip (ppm)	2	default
Volume of Layers	unk	
Flue Gas flow rate	unk	
Gas Temp at Inlet	750	
Base case fuel gas volumetric flow rate	516	default
Estimated operating life of catalyst	24,000	default
Estimated SCR equipment life (yrs)	16	default= 30, est startup 2023+3 years, retire 2042
Concentration of stored reagent	50	default 50 Urea, 29 ammonia
Density of reagent	71	default 71 Urea, 56 ammonia
Number of days reagent stored	14	default
Reagent	Urea	Choice
Desired dollar year	2016	default
CEPCI for goal year	541.7	default
CEPCI for 2016	541.7	default
Annual Interest Rate	5.5	default
Reagent cost	$ 1.66	default 1.66 urea, 0.293 ammonia
Electric cost	0.0361	default
Catalyst cost	$ 227	default
Operator Labor rate	$ 60	default
Operator hours/day	4	default
Maintenance Cost Factor	0.005	default
Administrative cost factor	0.03	default

Labadie SCR B3 & B4 All Inputs		Source
Retrofit Factor	1.2	default
MW Rating at full load capacity	690	Plant specific
HHV of fuel	8826	default
Estimated acutal MWhs output	4,000,000	Plant specific
Net Plant Heat input rate (mmbtu/MW)	9.64	Plant specific
Sulfur content of fuel	0.19	Plant specific
Number of days SCR operates	301	Plant specific
Number of days boiler operates	301	Plant specific
Inlet Nox	0.09	Plant specific
Outlet Nox	0.04	Choice
Stoichiometric Ratio Factor	0.525	default 0.525 Urea, 1.05 ammonia
Number of Chambers	1	
Number of catalyst layers	2	
Number of empty layers	1	
Ammonia slip (ppm)	2	default
Volume of Layers	unk	
Flue Gas flow rate	unk	
Gas Temp at Inlet	750	
Base case fuel gas volumetric flow rate	516	default
Estimated operating life of catalyst	24,000	default
Estimated SCR equipment life (yrs)	10	default= 30, est startup 2023+3 years, retire 2036
Concentration of stored reagent	50	default 50 Urea, 29 ammonia
Density of reagent	71	default 71 Urea, 56 ammonia
Number of days reagent stored	14	default
Reagent	Urea	Choice
Desired dollar year	2016	default
CEPCI for goal year	541.7	default
CEPCI for 2016	541.7	default
Annual Interest Rate	5.5	default
Reagent cost	$ 1.66	default 1.66 urea, 0.293 ammonia
Electric cost	0.0361	default
Catalyst cost	$ 227	default
Operator Labor rate	$ 60	default
Operator hours/day	4	default
Maintenance Cost Factor	0.005	default
Administrative cost factor	0.03	default

Ameren SNCR Calculations

Per the Control Cost Manual, the equations should not be used for outlet emissions below 0.1 lb/mmbtu, and Ameren units are already emitting below this rate.

Labadie SNCR Estimate

To get a general estimate of cost/ton, using potential emission reductions and general total costs to create an estimate.

Emission reductions possible at Labadie:

Current emissions rate:

0.09 lb/mmbtu
6,912.0 tons per year (avg 2016-2019)
7,000 rounded tons per year

At 20% reduction 1,400 tons reduced
At 15% reduction 1,050 tons reduced

Sum of NOx (tons)					
	2016	2017	2018	2019	Grand Total
Labadie	6,576	7,050	7,138	6,883	27,647
1	1,758	1,883	1,992	1,536	7,169
2	1,803	1,928	2,016	1,474	7,221
3	1,650	1,485	1,298	2,068	6,501
4	1,365	1,753	1,832	1,805	6,756
Rush Island	2,664	3,584	3,210	2,188	11,646
1	1,631	1,754	1,380	1,010	5,774
2	1,033	1,830	1,830	1,178	5,871

Estimated Control Efficiency	20% reduction	15% reduction
Tons Reduced	1,400	1,050
Cost Effectiveness Goal	Annualized Cost Threshold	
$5,000/ton	$ 7,000,000	$ 5,250,000
$8,000/ton	$ 11,200,000	$ 8,400,000
$10,000/ton	$ 14,000,000	$ 10,500,000

Typical breakdown of annual costs for utility boilers is 25% capital recovery, 75% operating expense (page 1-7)

Estimated Control Efficiency	20% reduction	15% reduction
Tons Reduced	1,400	1,050

NESCAUM study on BART from 2005 says capital cost of SNCR is $10 to $20/kw - use midpoint $15/kw

					2 units
675	MW =>	675,000.00	kw	$ 10,125,000	
each unit B1 and B2				in 2005 dollars	
				$ 13,162,500	$ 26,325,000
				in 2020 dollars	
690	MW =>	690,000.00	kw	$ 10,350,000	
each unit B3 and B4				in 2005 dollars	
				$ 13,455,000	$ 26,910,000
				in 2020 dollars	
				Plant Total SNCR Capital Installation Cost in 2020 dollars	$ 53,235,000

Avg annual cost per year

U1 &2 Lifetime		Capital Cost Divided by Operation Years
16	years (units 1 and 2 combined)	$ 1,645,313
	Per unit	$ 822,656.25

U3 &4 Lifetime		Capital Cost Divided by Operation Years
10	years (units 3 and 4 combined)	$ 2,691,000
	Per unit	$ 1,345,500

Plant Annual Capital Cost (25%) in 2020 dollars	$ 4,336,313
Plant Annual Operating Expense (75%) in 2020 dollars	$ 13,008,938
Plant Annualized Cost (total above) in 2020 dollars	$ 17,345,250

Tons reduced per year (@ 15% red)	1,050
Cost Effectiveness ($/ton)	16,519
in 2020 dollars	

Ameren – Labadie Control Technology Costs Based on 3.25% Interest Rate

Units 1, 2, 3, and 4
Sulfur Dioxide (SO_2)
Wet FGD

Appendix C - Four-Factor Analysis Infromation

Inputs	Source	B1	B2	B3	B4	
Full Load Capacity (MW)	nameplate	675	675	690	690	
Net Plant Heat input rate (MMBtu/MW)	design rate/max load with 5% reduction	9.64	9.64	9.32	9.32	
Max heat input rate (Mmbtu/hr)	design rate	6183	6183	6107	6107	
Max annual MW Output	Calc: MW nameplate *8760	5,913,000	5,913,000	6,044,400	6,044,400	
Est annual MW Output	Estimated from averaged past air markets data	4,140,000	4,140,000	4,000,000	4,000,000	
Est time control operates	Estimate from past air markets data	7,712	7,517	7,226	7,864	
Est time boiler operates	Estimate from past air markets data	7,712	7,517	7,226	7,864	
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.700	0.700	0.662	0.662	
SO2 baseline lb/mmbtu	Estimated from averaged past air markets data	0.44	0.44	0.44	0.44	
SO2 Outlet lb/mmbtu	Estimated after control added	0.05	0.05	0.05	0.05	
SO2 Removal Efficiency	Calc (SO2in-SO2out)/SO2 in	89%	89%	89%	89%	
SO2 Removed per Hour (lb/hr)	Calc (SO2in * Effic * Max annual heat input rate)	2411	2411	2382	2382	
Total SO2 Removed per year (tons)	Calc: SO2 per hr removed * Time control operates/2000	7395	7395	6904	6904	
Retrofit Factor		1.50	1.50	1.50	1.50	
Remaining Equipment Life	Based on Construction Time and Remaining Life of Unit	14	14	8	8	
Number of Additional Personnel	Default from Manual	16	16	16	16	
Hourly Labor Rate	Default from Manual	60	60	60	60	
Limestone Cost ($/ton)	Updated based on Ameren specific data	60	60	60	60	
Make-up water cost ($/gallon)	Updated based on Ameren specific data	0.0063	0.0063	0.0063	0.0063	
Waste Disposal ($/ton)	Default from Manual	30	30	30	30	
Electricity Cost ($/kwh)	Default from Manual	0.0361	0.0361	0.0361	0.0361	
Assumed Interest Rate	Default from Manual (NOx and SO2 sections were different. Using NOx value since SO2 section is still in draft)	3.3%	3.3%	3.3%	3.3%	
	Capital Cost (2016 $)	$ 412,560,278	$ 412,560,278	$ 413,043,826	$ 413,043,826	
	Direct Annual Cost (2016 $)	$ 12,149,551	$ 12,149,551	$ 11,779,837	$ 11,779,837	
	Annualized Cost (2016 $)	$ 49,406,615	$ 49,406,615	$ 71,352,184	$ 71,352,184	**Total**
	Captial Cost (2020 $)	$ 445,565,100	$ 445,565,100	$ 446,087,333	$ 446,087,333	**$1,783,304,865**
	Direct Annual Cost (2020 $)	$ 13,121,516	$ 13,121,516	$ 12,722,224	$ 12,722,224	**$ 51,687,480**
	Annualized Cost (2020 $)	$ 53,359,144	$ 53,359,144	$ 77,060,358	$ 77,060,358	**$ 260,839,004**
	Cost Effectiveness (2020 $/ton)	$ 7,216	$ 7,216	$ 11,162	$ 11,162	

Ameren Study Cost Estimations	B1	B2	B3	B4	Total
Captial Cost (2020 $)	$ 447,660,000	$ 447,660,000	$ 447,660,000	$ 447,660,000	**$1,790,640,000**
Direct Annual Cost (2020 $)	$ 7,560,000	$ 7,560,000	$ 7,560,000	$ 7,560,000	**$ 30,240,000**
Annualized Cost (2020 $)	$ 47,868,092.55	$ 47,868,092.55	$ 72,006,312.58	$ 72,006,312.58	**$ 239,748,810**
Cost Effectiveness (2020 $/ton)	$ 6,473	$ 6,473	$ 10,430	$ 10,430	

SDA

Inputs	Source	B1	B2	B3	B4	
Full Load Capacity (MW)	nameplate	675	675	690	690	
Net Plant Heat input rate (MMBtu/MW)	design rate/max load with 5% reduction	9.64	9.64	9.32	9.32	
Max heat input rate (Mmbtu/hr)	design rate	6183	6183	6107	6107	
Max annual MW Output	Calc: MW nameplate *8760	5,913,000	5,913,000	6,044,400	6,044,400	
Est annual MW Output	Estimated from averaged past air markets data	4,140,000	4,140,000	4,000,000	4,000,000	
Est time control operates	Estimate from past air markets data	7,712	7,517	7,226	7,864	
Est time boiler operates	Estimate from past air markets data	7,712	7,517	7,226	7,864	
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.700	0.700	0.662	0.662	
SO2 baseline lb/mmbtu	Estimated from averaged past air markets data	0.44	0.44	0.44	0.44	
SO2 Outlet lb/mmbtu	Estimated after control added	0.06	0.06	0.06	0.06	
SO2 Removal Efficiency	Calc (SO2in-SO2out)/SO2 in	86%	86%	86%	86%	
SO2 Removed per Hour (lb/hr)	Calc (SO2in * Effic * Max annual heat input rate)	2350	2350	2321	2321	
Total SO2 Removed per year (tons)	Calc: SO2 per hr removed * Time control operates/2000	7205	7205	6727	6727	
Retrofit Factor		1.50	1.50	1.50	1.50	
Remaining Equipment Life	Based on Construction Time and Remaining Life of Unit	14	14	8	8	
Number of Additional Personnel	Default from Manual	8	8	8	8	
Hourly Labor Rate	Default from Manual	60	60	60	60	
Lime Cost ($/ton)	Default from Manual	125	125	125	125	
Make-up water cost ($/gallon)	Updated based on Ameren specific data	0.0063	0.0063	0.0063	0.0063	
Waste Disposal ($/ton)	Default from Manual	30	30	30	30	
Electricity Cost ($/kwh)	Default from Manual	0.0361	0.0361	0.0361	0.0361	
Assumed Interest Rate	Default from Manual (NOx and SO2 sections were different. Using NOx value since SO2 section is still in draft)	3.3%	3.3%	3.3%	3.3%	
	Capital Cost (2016 $)	$ 379,080,000	$ 379,080,000	$ 387,504,000	$ 387,504,000	
	Direct Annual Cost (2016 $)	$ 10,346,077	$ 10,346,077	$ 10,064,181	$ 10,064,181	
	Annualized Cost (2016 $)	$ 44,554,548	$ 44,554,548	$ 65,926,730	$ 65,926,730	**Total**
	Captial Cost (2020 $)	$ 409,406,400	$ 409,406,400	$ 418,504,320	$ 418,504,320	**$1,655,821,440**
	Direct Annual Cost (2020 $)	$ 11,173,764	$ 11,173,764	$ 10,869,315	$ 10,869,315	**$ 44,086,158**
	Annualized Cost (2020 $)	$ 48,118,912	$ 48,118,912	$ 71,200,868	$ 71,200,868	**$ 238,639,559**
	Cost Effectiveness (2020 $/ton)	$ 6,678	$ 6,678	$ 10,585	$ 10,585	

DSI*

	With Fabric Filter					
Labadie		assumed 70% removal efficiency				
Inputs	**Source**	**B1**	**B2**	**B3**	**B4**	
Full Load Capacity (MW)	nameplate	675	675	690	690	
Max heat input rate (Mmbtu/hr)	design rate	6183	6183	6107	6107	
Max annual MW Output	Calc: MW nameplate *8760	5,913,000	5,913,000	6,044,400	6,044,400	
Est annual MW Output	Estimated from averaged past air markets data	4,140,000	4,140,000	4,000,000	4,000,000	
Est time control operates	Estimate from past air markets data	7,712	7,517	7,226	7,864	
Est time boiler operates	Estimate from past air markets data	7,712	7,517	7,226	7,864	
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.700	0.700	0.662	0.662	
SO2 baseline lb/mmbtu	Estimated from averaged past air markets data	0.44	0.44	0.44	0.44	
SO2 Outlet lb/mmbtu	Estimated after control added	0.13	0.13	0.13	0.13	
SO2 Removal Efficiency		70%	70%	70%	70%	
Assumed Interest Rate	Default from Manual (using NOx section interest rate)	3.25%	3.25%	3.25%	3.25%	
Remaining Equipment Life	Based on Construction Time and Remaining Life of Unit	16	16	10	10	
Capital Recovery Factor		0.0811	0.0811	0.1187	0.1187	
SO2 Removed per Hour (lb/hr)	Calc (SO2in * Effic * Max annual heat input rate)	1917	1917	1893	1893	
Total SO2 Removed per year (tons)	Calc: SO2 per hr removed * Time control operates/2000	5878	5878	5487	5487	**Total**
	Captial Cost (2020 $)	$ 143,424,000	$ 143,424,000	$ 143,424,000	$ 143,424,000	**$ 573,696,000**
	Direct Annual Cost (2020 $)	21,963,200	21,963,200	21,963,200	21,963,200	**$ 87,852,800**
	Annualized Cost (2020 $)	$ 33,600,642	$ 33,600,642	$ 38,992,085	$ 38,992,085	**$ 145,185,455**
	Cost Effectiveness (2020 $/ton)	$ 5,716	$ 5,716	$ 7,106	$ 7,106	

Units 1 and 2
Nitrogen Oxides (NO_x)
SCR – Ammonia

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}) =	$140,176,412	in 2016 dollars
Reagent Preparation Cost (RPC) =	$2,874,406	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2016 dollars
Balance of Plant Costs (BPC) =	$9,843,655	in 2016 dollars
Total Capital Investment (TCI) =	$198,762,813	in 2016 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.

$214,663,838.57

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}) =	$140,176,412 in 2016 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) =	$2,874,406 in 2016 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 2016 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}) =	$9,843,655 in 2016 dollars

Annual Costs

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

Direct Annual Costs (DAC) =	$2,553,498 in 2016 dollars
Indirect Annual Costs (IDAC) =	$16,133,901 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$18,687,399 in 2016 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 =	$993,814 in 2016 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$104,667 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$841,318 in 2016 dollars
Annual Catalyst Replacement Cost =		$613,698 in 2016 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 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 =		$2,553,498 in 2016 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) =	$14,237 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$16,119,664 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$16,133,901 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$18,687,399 per year in 2016 dollars
NOx Removed =	998 tons/year
Cost Effectiveness =	$18,730 per ton of NOx removed in 2016 dollars
	$20,182,390.74
	$20,228.11

SCR – Urea

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}) =	$140,176,412	in 2016 dollars
Reagent Preparation Cost (RPC) =	$2,874,406	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2016 dollars
Balance of Plant Costs (BPC) =	$9,843,655	in 2016 dollars
Total Capital Investment (TCI) =	$198,762,813	in 2016 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.

$214,663,838.57

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}) =	$140,176,412 in 2016 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) =	$2,874,406 in 2016 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 2016 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}) =	$9,843,655 in 2016 dollars

Annual Costs

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

Direct Annual Costs (DAC) =	$2,927,185 in 2016 dollars
Indirect Annual Costs (IDAC) =	$16,133,901 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$19,061,086 in 2016 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 =	$993,814 in 2016 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$478,355 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$841,318 in 2016 dollars
Annual Catalyst Replacement Cost =		$613,698 in 2016 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 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 =		$2,927,185 in 2016 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) =	$14,237 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$16,119,664 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$16,133,901 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$19,061,086 per year in 2016 dollars
NOx Removed =	998 tons/year
Cost Effectiveness =	$19,104 per ton of NOx removed in 2016 dollars

$20,585,973.17
$20,632.60

Units 3 and 4
Nitrogen Oxides (NO_x)
SCR – Ammonia

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}) =	$143,039,713	in 2016 dollars
Reagent Preparation Cost (RPC) =	$2,890,243	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2016 dollars
Balance of Plant Costs (BPC) =	$9,934,943	in 2016 dollars
Total Capital Investment (TCI) =	$202,624,370	in 2016 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.

$218,834,319.50

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}) =	$143,039,713 in 2016 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) =	$2,890,243 in 2016 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 2016 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}) =	$9,934,943 in 2016 dollars

Annual Costs

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

Direct Annual Costs (DAC) =	$2,554,453 in 2016 dollars
Indirect Annual Costs (IDAC) =	$24,065,837 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$26,620,291 in 2016 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 =	$1,013,122 in 2016 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$101,128 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$812,867 in 2016 dollars
Annual Catalyst Replacement Cost =		$627,336 in 2016 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 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 =		$2,554,453 in 2016 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) =	$14,325 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$24,051,513 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$24,065,837 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$26,620,291 per year in 2016 dollars
NOx Removed =	964 tons/year
Cost Effectiveness =	$27,614 per ton of NOx removed in 2016 dollars
	$28,749,914.01
	$29,823.56

SCR – Urea

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}) =	$143,039,713	in 2016 dollars
Reagent Preparation Cost (RPC) =	$2,890,243	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2016 dollars
Balance of Plant Costs (BPC) =	$9,934,943	in 2016 dollars
Total Capital Investment (TCI) =	$202,624,370	in 2016 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.

$218,834,319.50

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}) =	$143,039,713 in 2016 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) =	$2,890,243 in 2016 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 2016 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}) =	$9,934,943 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	$2,915,504 in 2016 dollars
Indirect Annual Costs (IDAC) =	$24,065,837 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$26,981,341 in 2016 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 =	$1,013,122 in 2016 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$462,179 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$812,867 in 2016 dollars
Annual Catalyst Replacement Cost =		$627,336 in 2016 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 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 =		$2,915,504 in 2016 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) =	$14,325 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$24,051,513 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$24,065,837 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$26,981,341 per year in 2016 dollars
NOx Removed =	964 tons/year
Cost Effectiveness =	$27,989 per ton of NOx removed in 2016 dollars

$29,139,848.72

$30,228.06

Units 1, 2, 3 and 4
Nitrogen Oxides (NO_x)
SNCR

Per the Control Cost Manual, the equations should not be used for outlet emissions below 0.1 lb/mmbtu, and Ameren units are already emitting below this rate.

Labadie SNCR Estimate

To get a general estimate of cost/ton, using potential emission reductions and general total costs to create an estimate.

Emission reductions possible at Labadie:

Current emission	B1	B2	B3	B4	
	0.09	0.09	0.09	0.09	lb/mmbtu
	1,792.25	1,805.250	1,625.250	1,688.750	tons per year (avg 2016-2019)
	1,800	1,800	1,700	1,700	rounded tons per year
At 20% reduction	360	360	340	340	tons reduced
At 15% reduction	270	270	255	255	tons reduced

Sum of NOx (tons)					
	2016	2017	2018	2019	Average
Labadie	6,576	7,049	7,138	6,883	6,912
B1	1,758	1,883	1,992	1,536	1,792
B2	1,803	1,928	2,016	1,474	1,805
B3	1,650	1,485	1,298	2,068	1,625
B4	1,365	1,753	1,832	1,805	1,689
Rish Island	2,664	3,584	3,210	2,188	2,912
B1	1,631	1,754	1,380	1,010	1,444
B2	1,033	1,830	1,830	1,178	1,468

Estimated Control			
Efficiency	15%	20%	eduction
Tons Reduced	1050	1400	
Cost Effectiveness			
Goal	Annualized Cost Threshold		
$5,000/ton	$ 5,250,000	$ 7,000,000	
$8,000/ton	$ 8,400,000	$ 11,200,000	
$10,000/ton	$ 10,500,000	$ 14,000,000	

Typical breakdown of annual costs for utility boilers is 25% capital recovery, 75% operating expense (page 1-7)

NESCAUM study on BART from 2005 says capital cost of SNCR is $10 to $20/kw - use midpoint $15/kw

	Base Load (MW)	Base Load (KW)	Capital Cost 2005 $	Capital Cost 2020 $	Life Time	Annual Cost 2020 $	Annual Operating Expense (75	Total Cost	Cost Effectiveness ($/ton)
B1	675	675,000	10,125,000	13,162,500	16	822,656	2,467,969	3,290,625	12,188
B2	675	675,000	10,125,000	13,162,500	16	822,656	2,467,969	3,290,625	12,188
B3	690	690,000	10,350,000	13,455,000	10	1,345,500	4,036,500	5,382,000	21,106
B4	690	690,000	10,350,000	13,455,000	10	1,345,500	4,036,500	5,382,000	21,106
	Plant Total SNCR Capital Installation Cost			53,235,000.00	Plant	4,336,313	13,008,938	17,345,250	16,519

Ameren Missouri additional information in response to the FLMs and EPA's comments during the 60-day formal consultation period

The following is supplemental information on Ameren Missouri's Regional Haze submission addressing comments on Retrofit Cost Factors for the large AQCS additions and the design parameters for the application of DSI for SO2 control.

Retrofit Cost Factors

Comments submitted to Missouri Department of Natural Resources Air Pollution Control Program on the draft Four Factor Analysis conducted for the second planning period of the Regional Haze Program were critical of the capital cost estimates for several SO2 control technologies and specifically the use of a retrofit factor in those capital cost estimates. The retrofit factors were proposed and used when site specific analyses conducted by Ameren resulted in significantly different costs than the estimates made using the US EPA's control cost manual cost equations. The retrofit factors proposed escalated costs to match engineering cost estimates which took into account site conditions at the Ameren Missouri Labadie Energy Center as this is the purpose of the retrofit factor. Below is a discussion of the reasons for the increased costs of a retrofit of the Labadie Energy Center to include additional SO2 controls.

When determining the total cost of a project, it is important to consider capital costs, operating costs and opportunity costs. Capital costs are the costs for engineering, design, materials, and labor. Operating costs are those costs for operating a fully constructed facility. Opportunity costs are those costs which a facility acquires or loses as a result of the project. Opportunity costs can have a significant impact on a project's cost at an existing facility if a project requires a facility to shutdown existing operations to accommodate a long construction schedule. At electric generating facilities, lost generation and lost revenue as a result of generator outages cannot be recovered. These impact the costs to a company in the form of lost opportunity costs.

To avoid lost opportunity costs, Facility owners will design projects which require installation of new equipment in a way that minimizes these lost opportunity costs. Site congestion makes design, engineering and construction of a new project more costly at large complex installations like Labadie Energy Center partly because of efforts to minimize lost opportunity costs. The cost estimates provided by Ameren Missouri are based on engineering design efforts that minimize lost opportunity costs and that increase the capital cost of the design as a result.

As discussed in the original Four Factor Analysis Information Collection Request Response submitted on October 20, 2020, a congested site can also increase the capital cost of a project in the following ways:

1. A congested site often requires modification or relocation of existing unrelated facilities or processes which are not part of the process for new greenfield construction.
2. A congested site increases the difficulty of construction (increasing labor and material costs) as a result of the need to work around ongoing production or as a result of an inability of construction equipment to access congested or hazardous areas. For example, congested sites with ongoing operations make fitting the large cranes and other large construction equipment into the site difficult with nearby energized equipment or other overhead obstacles.
3. A congested site requires new and/or innovative construction methods which increase the amount of labor and associated labor costs. Innovative construction methods can also result in construction delays which increase construction costs.
4. A congested site requires additional construction material by increasing the facility operating footprint and/or by increasing the difficulty of construction by requiring construction to occur under more hazardous conditions such as at high elevations.

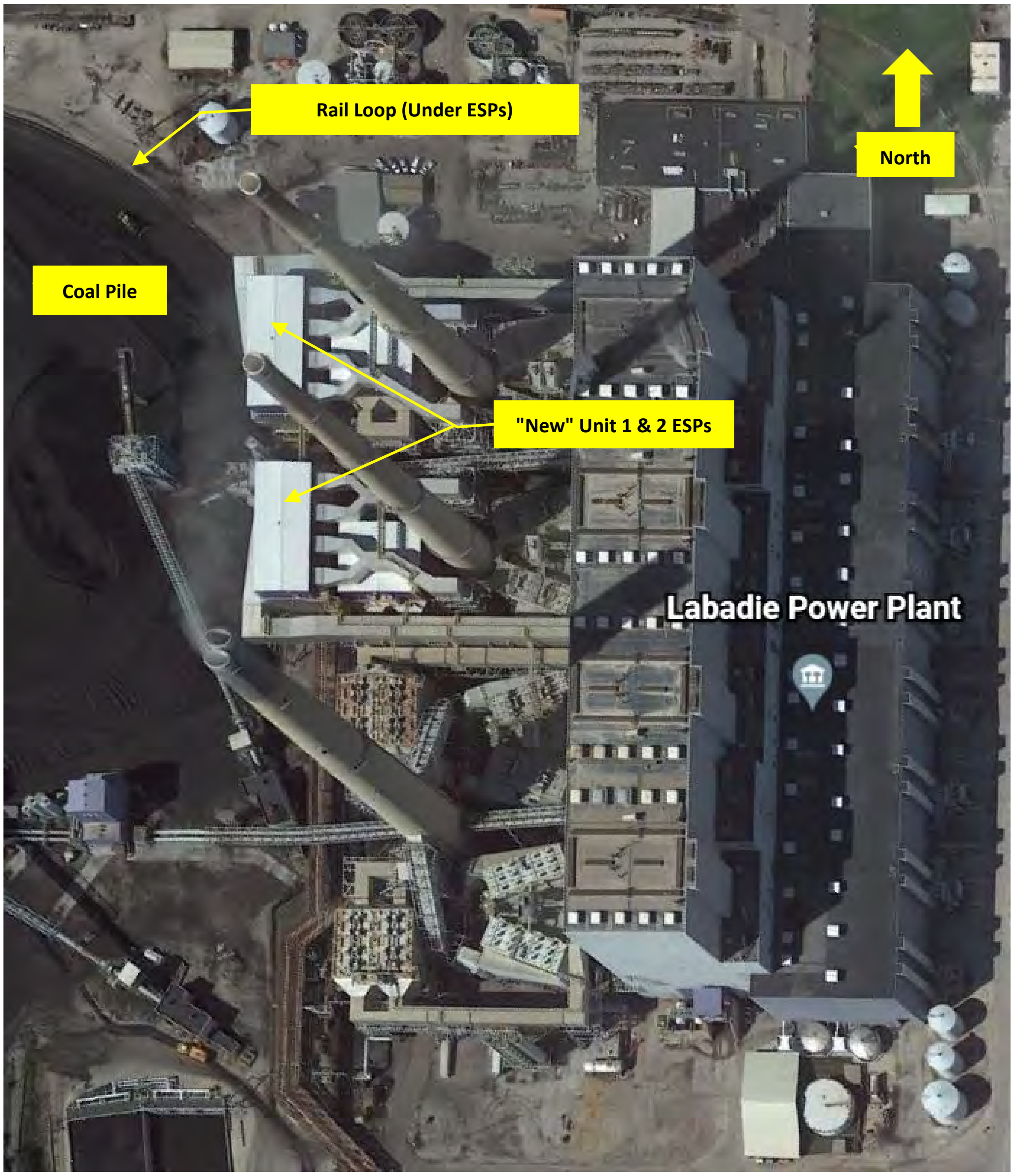


Figure 1. Google Earth Image Showing the Labadie Energy Center Site Congestion

As shown in the figure above, the Labadie Energy Center site is very congested making any major retrofits, particularly, back-end air quality control system (AQCS) modifications very challenging.

For example, Unit 1 and Unit 2 electrostatic precipitator modifications included the installation of new ESP boxes for compliance with the Mercury and Air Toxics Standards. These new ESP boxes were added to the existing flue gas path and ductwork after the existing ESP boxes from 2014 to 2016. The congested site necessitated constructing this equipment at an elevated position over the existing coal train rail loop and coal unloading equipment and structures. This required routing and installing new ductwork and new AQCS controls at elevated heights above and supported by existing structures requiring significant structural reinforcements including subsurface pile caps.

When making an engineering estimate of the capital costs for a WFGD, Ameren first considered the necessary equipment as this is a primary element of the design. Installation of one or several WFGD systems at Labadie would necessarily include lime/limestone unloading and storage facility, a reagent mix/prep facility, a pump house(s), absorber vessel(s)/spray tower(s), and a new stack(s). While the unloading and storage facilities could potentially be further away, the absorber vessel(s)/spray tower(s), pump house(s), mix/prep facility(ies) and the new stacks would need to be located near the units being controlled. Use of the area inside the rail loop (see Figure 1 above) which includes the coal pile, coal unloading, and coal reclaim facilities were necessarily excluded as relocation of any of these facilities would require significant capital cost and also require significant unit downtime (lost opportunity costs). The WFGD must necessarily collect the flue gas after routing through the ESPs, therefore the WFGD facilities must be on the stack side of the boiler house. Because of the existing ESPs and ash handling equipment located in this area as well as the existing stacks and coal belts, there isn't enough room to install absorber vessels and new stacks anywhere between the boiler house and the existing stacks. The only available open location for these facilities is an open area to the south of the existing plant.

Figure 2 shows the proposed location for a WFGD retrofit for Labadie's four units with the absorber vessels, new wet stacks, and support equipment south of the main plant building, requiring new flue gas ductwork to run over 800 feet in length and over 130 feet above ground. Because of all of the existing equipment, there is little room for new columns with the associated pile and pile caps to the support this new ductwork. This location and configuration has been identified as the lowest total cost option (i.e. combined capital and operating costs) as other possible locations will result in the modification of other plant systems (increased capital costs) and/or significant plant downtime for the modifications and the associated increased lost opportunity costs resulting from the inability of Labadie Energy Center to operate during construction.

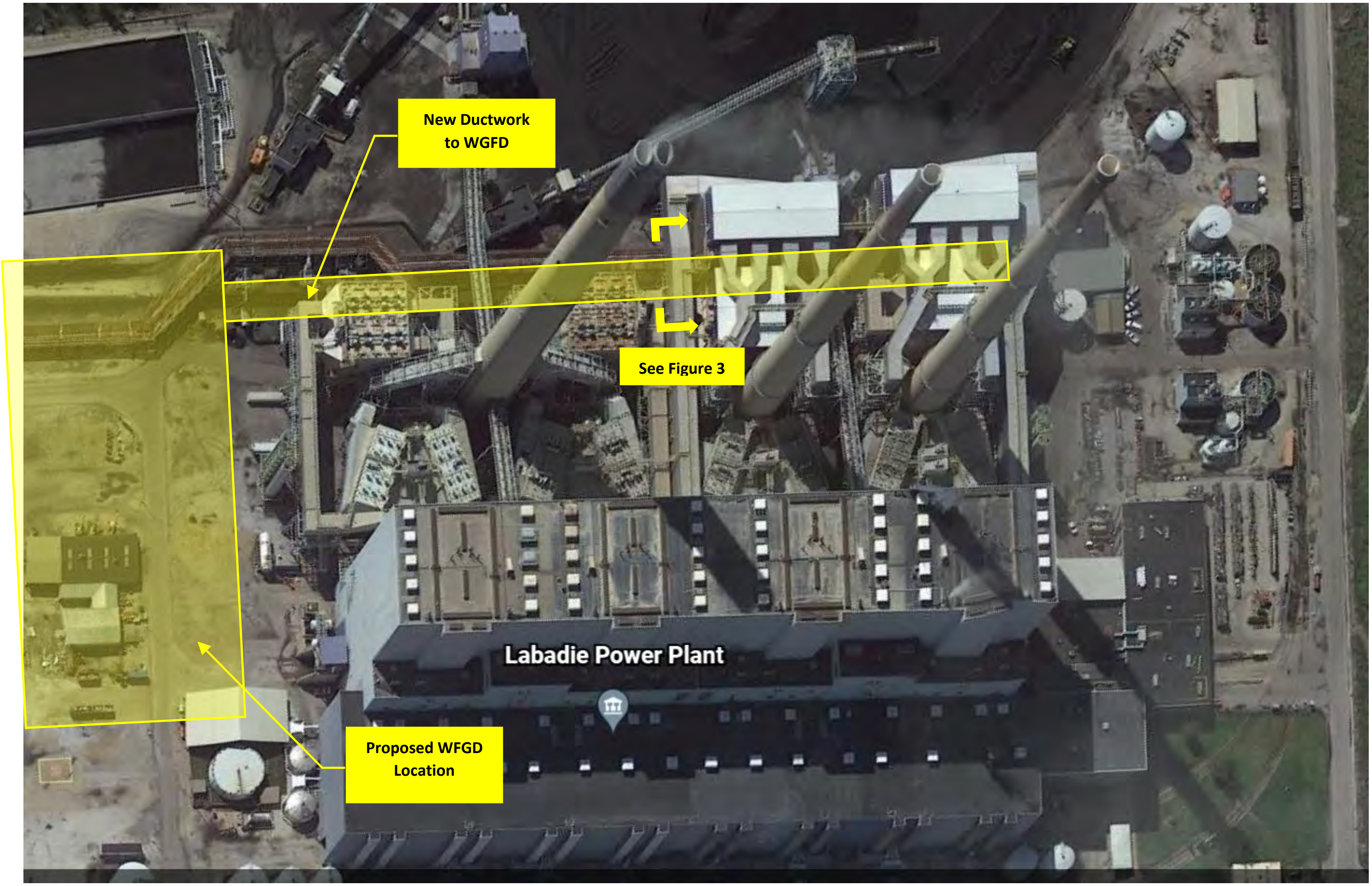


Figure 2. Google Earth Image Indicating the Potential Labadie WFGD Locations

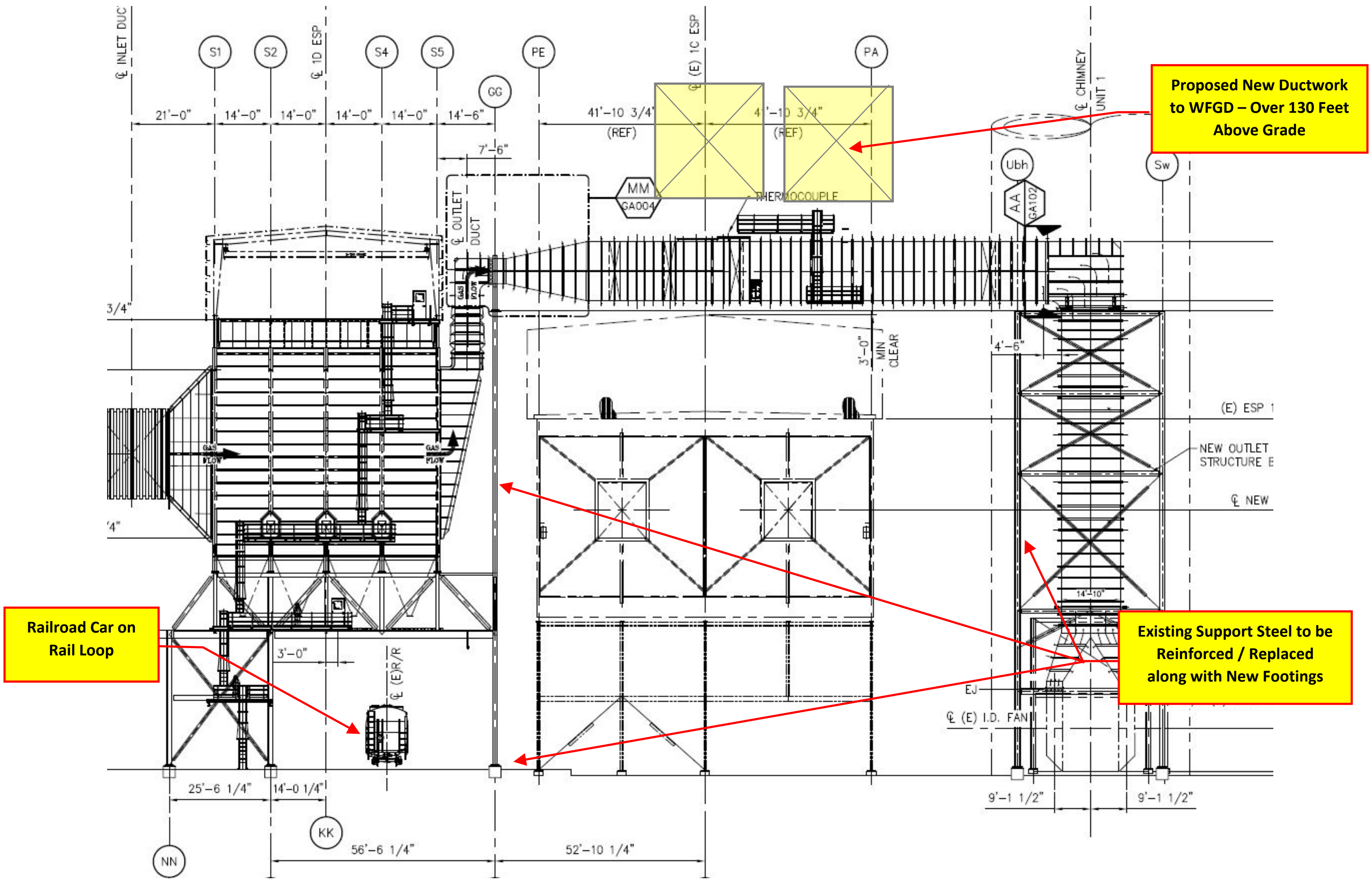


Figure 3. Annotated Drawing Excerpt Indicating the Ductwork Support Complications

All of the overhead interferences make it very difficult to drive pile as traditionally performed, requiring reinforcement of existing steel, foundations, pile caps, and installation of alternate piles. Due to the height and the need to meet current wind and seismic codes adds considerable complexity and cost.

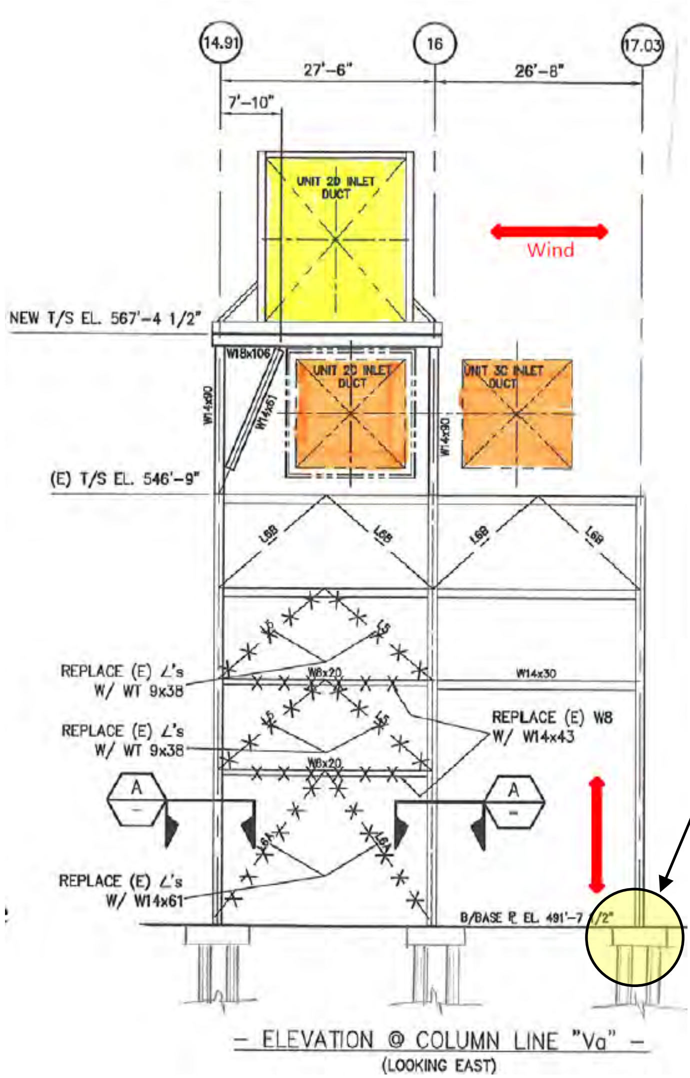


Figure 4. Illustrative Example of Using Existing Structure for Ductwork Support

Figure 5. Photo of an Existing Column Being Temporary Supported while the Pile Cap is Replaced

Dry Sorbent Injection Information

Figure 6. Layout of Potential DSI System at Labadie Energy Center

Dry Sorbent Injection (cont'd.)

Comments received by MDNR on the estimated costs for Dry Sorbent Injection (DSI) system(s) are critical and propose alternative cost estimates for DSI. As stated in Ameren's response to MDNR's Regional Haze Four Factor Analysis – Information Collection Request, DSI control system costs are not included in the USEPA's Control Cost Manual and so the basis for Federal Land Manager (FLM) estimates of DSI costs are uncertain. Ameren estimates are based on previously conducted DSI engineering cost estimates and are based on site specific evaluation of costs. It is also noted that FLM estimates of DSI costs assume that Labadie Energy Center units already include baghouse particulate controls and thereby overstate the potential SO2 control rate and underestimate the amount of required sorbent and the associated costs.

DSI systems control SO2 by injecting a sorbent (e.g. trona) into the flue gas ductwork upstream of particulate controls. The sorbent adsorbs the SO2 and is removed by the particulate control system with the fly ash. However, the DSI system does not start at the flue gas ductwork and does not end at the particulate control device. DSI systems require several additional system parts to control SO2. DSI systems include sorbent delivery, unloading and storage systems as well as sorbent conveying systems. Sorbent which is removed from the particulate control device with the fly ash must be transported and disposed. Each of these parts of the system (including sorbent delivery) will necessarily emit particulates (e.g. haul road fugitive dust, sorbent transfer particulate emissions as well as increased stack particulate) and all of these sources of emissions contribute to a detemination of whether or not DSI system installation will exceed New Source Review significant increase levels and be required to obtain a Prevention of Significant Deterioration (PSD) permit and meet Best Available Control Technology (BACT) requirements. Below we explain some of the site specific issues that impact cost estimates for installing and operating DSI system(s) at Labadie Energy Center units.

The biggest challenge with installation and operation of DSI systems is control of particulate matter emissions related to the injection of the large amounts of sorbent into the flue gas stream. Coal fired EGUs like the Labadie Energy Center units must meet the stringent PM standards of the Mercury and Air Toxics (MATS) rule. Not only does the particulate control device need to control particulate matter in the flue gas to meet the current MATS limits, it would need to limit the increased PM emission rates for all new equipment to less than the significance levels for a PSD (Prevention of Significant Deterioration) permit. Otherwise, the DSI systems will require a PSD permit be obtained with a BACT limit for PM. BACT in this case is assumed to be the addition of a baghouse; if a baghouse is required, this will further complicate the congested footprint). While sodium-based sorbents can improve fly ash resistivity and ESP performance, very high injection rates can result in increased PM emissions. The figure below shows data from an Ameren DSI test. The testing was performed on ½ of the flue gas from a single unit and the sorbent injection rates are ½ of those required for full scale implementation. As shown in Figure 7, for SO2 reductions of greater than 50%, greater than 10,000 lbs. of sorbent per hour would need to be injected per unit. This amount of sorbent would likely overwhelm the existing ESP controls and major ESP upgrades or baghouses would be required to meet PM limits or the requirement of PSD. ESP upgrades or a baghouse retrofit would cost significantly more and have a much high annual O&M cost. The cost estimates provided in Ameren's response to MDNR's Regional Haze Four Factor Analysis – Information Request assumed a 70 % control efficiency at a sorbent injection rate of 8-10 tons per hour per unit based on the data from the test results shown in Figure 7. The estimates also assumed that baghouses would be required with any DSI upgrades in order to achieve 70 % control.

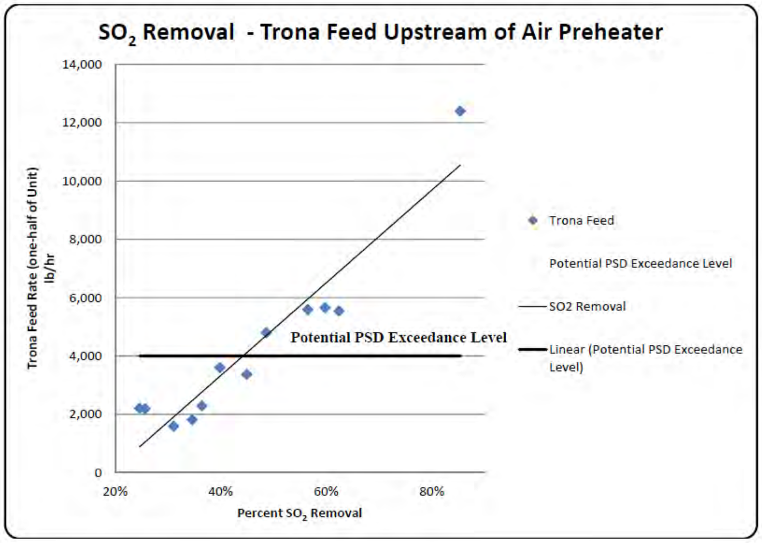


Figure 7. SO2 Removal – 2011 Test Results

Once the sorbent is removed from the flue gas with the fly ash via the particulate control system (whether ESP or baghouse), it must then be transported, stored and landfilled. Existing ash handling systems were designed for the highest projected ash production and removal rates, given actual projections of coal supply conditions and for the ultimate sale of ash as a saleable by-product. The high sorbent injection rates required for high SO2 reductions will exceed current system capacity and will necessitate upgrades to the existing ash handling systems including expansion of the ash storage capacities. It will also degrade the ash and potentially make the ash an unwanted by-product which must be landfilled.

To achieve a 70 % control efficiency per unit, the necessary sorbent feedrate would require multiple sorbent truck deliveries every hour (assuming deliveries 24 hours a day and 7 days a week). A rail unloading facility would likely be required not only to more efficiently deliver the sorbent, but to also eliminate the associated truck traffic through local towns and minimize fugitive dust emissions from haul roads. To ensure this rail unloading facility does not interfere with existing traffic and other plant operations such as coal deliveries, it will need to be a long distance from the silo and injection locations, which would further complicate the sorbent handling.

Similar to the existing activated carbon injection (ACI) systems shown in Figure 6 for mercury control, sorbent material properties and emission control requirements for DSI sorbents limit material conveying options for DSI systems to the use of pneumatic conveying to move the sorbent from the unloading operations to the storage silos to the boiler. For Labadie, the Unit 2 and Unit 3 systems are challenging since their silos will be further away from the unit, resulting in long conveying distances, which is especially concerning for hygroscopic materials. As a result of the potential long conveying distances, additional engineering, equipment (air dryers) and construction may be required.

With regards to sorbent selection, industry and Ameren experience indicate DSI results are very unit specific and vary with different sorbents, injection locations and arrangements, and of course, particulate matter controls. If implementing DSI at Labadie, Ameren would need to embark on a multimillion dollar testing program to determine the best sorbent and injection strategy prior to implementing full scale design of these systems. This testing would span several month, and need to include testing of the ESP performance and ash handling systems under various conditions.

Summary of the Air Program Evaluation

In conclusion, based on a review of possible and feasible options to reduce SO2 and NOx emissions at Unit 1, the Air Program has determined that there are no cost-effective methods of SO2 and NOx reduction for this facility. All Class I areas impacted by sources in Missouri have made steady and significant improvement in visibility, and modeling shows they are projected to be below, or well below, their uniform rate of progress (URP) glidepaths in 2028. Based on the four factor analysis completed in this report, the Air Program is proposing to maintain current operational practices consistent with the parameters and limits in Labadie Air Pollution Control Title V Permit to Operate.

**All control cost estimate calculations for wet FGD, SDA, and DSI for both remaining useful life (RUL) scenarios are provided in the attached 34 spreadsheets.

Example of the spreadsheets

Labadie boiler 1 SCR urea-EPA-RUL.xlsm
Labadie boiler 1 SCR urea-Original-RUL.xlsm

All spreadsheets are in Missouri Regional Haze Plan for the Second Planning Period, Attachment C https://dnr.mo.gov/document-search/missouri-regional-haze-plan-second-planning-period-attachment-c

C-7 Rush Island Energy Center Four-Factor Analysis

Ameren MISSOURI

October 15, 2020

Ms. Darcy Bybee, Director
Air Pollution Control Program
Missouri Department of Natural Resources
P.O. Box 176
Jefferson City, MO 65102

Re: Regional Haze Four-Factor Analysis – Information Collection Request
Ameren Missouri Rush Island Energy Center
Installation ID: 099-0016

Dear Ms. Bybee:

Union Electric Company, d/b/a Ameren Missouri, herein responds to the subject Information Collection Request letter from MDNR dated July 29, 2020. In the letter, MDNR requested certain information required for the Missouri Department of Natural Resources' (MDNR) Regional Haze four-factor analysis for the Ameren Missouri Rush Island Energy Center located at 100 Big Hollow Road in Festus, Missouri. Based on the letter, the four-factor analysis is required to evaluate technically feasible SO_2 and NOx control technologies for Boilers 1 and 2. This is required to be included as part of MDNR's development of a strategy for meeting reasonable progress goals for visibility impairment at Class 1 areas during the 2028 planning period.

The attached report contains information on cost estimations using the USEPA Air Pollution Control Cost Manual and Ameren site specific studies previously performed to determine the overall cost effectiveness of installing additional emission controls on Rush Island's units. The coal fired steam electric generating units (EGUs) at the Rush Island Energy Center utilize a variety of lower emitting processes that include the following technologies: ultra-low sulfur fuel, low NOx burners, overfire air (OFA) systems, and neural network optimization systems. These existing technologies minimize emissions and Ameren utilizes post combustion controls to further control mercury, non-mercury metals and particulate matter. Because of the already low emission rates, the installation of additional post combustion controls would have negligible overall impact.

In accordance with the information collection request, evaluations of the four Regional Haze Rule factors, including costs have been included for Wet Flue Gas Desulfurization (Wet FGD), Spray Dry Absorbers (SDA), Dry Sorbent Injection (DSI), Selective Catalytic Reduction (SCR), and Selective Non-Catalytic Reduction (SNCR) controls. That information is provided in the attached report. Qualitative assessments were performed for the other emission controls where quantitative evaluation methodologies from USEPA were unavailable.

Please feel free to contact Michael Hutcheson (mhutcheson@ameren.com) or myself (swhitworth@ameren.com), at your convenience if you have questions or if you need additional information.

Sincerely,

Steven C. Whitworth
Senior Director, Environmental Policy and Analysis

Attachment

Response to Missouri Department of Natural Resources
Regional Haze Four-Factor Analysis - Information Collection Request
Dated July 29, 2020
For the Rush Island Energy Center

Ameren Missouri
Environmental Services
1901 Chouteau Ave.
St. Louis, MO

Ameren Regional Haze Response

Table of Contents

I. Introduction

Ameren is providing the following information in response to the Missouri Department of Natural Resources (MDNR) letter regarding Regional Haze Four Factor Analysis-Information Collection Request dated July 29, 2020. The MDNR letter requests data and information for an analysis of the potential SO_2 and NOx emission reduction strategies at the Rush Island Energy Center coal fired steam electric generating units (EGUs). The information has been requested to facilitate MDNR's development of Missouri's Regional Haze Rule state implementation plan (SIP).

The Regional Haze rule requires states to develop a long term strategy for reducing emissions from sources impacting visibility at Class I areas with a goal of returning to natural visibility conditions by 2064. The Regional Haze Rule provides four factors for states to consider when developing its potential control strategy. All four of these factors are discussed in this response. Specifically, Ameren is providing the following information:

1. The cost of potential emission control strategies for Rush Island Energy Center EGUs are detailed below as requested in the subject information collection request. In cases where detailed cost estimates for certain technologies were not available, a qualitative analysis of the feasibility and comparable cost of the technology are included.
2. The time required for the installation of the potential control strategies for the Rush Island Energy Center EGUs is detailed below including the engineering, permitting, procurement and construction timelines. Also discussed is the impact on timing that would result from control requirements on multiple units and units at multiple facilities.
3. The remaining useful life of the Rush Island Energy Center EGUs are discussed as outlined in Ameren's recently released 2020 Integrated Resource Plan.
4. The energy and non-air quality environmental impacts of potential control strategies are discussed where those costs or impacts are identifiable.

The cost analyses included in this response to the MDNR request for information are not detailed engineering evaluations of each potential control option. The analyses provided herein have been performed at the behest of MDNR and we emphasize that they represent first order estimates prepared without the detailed engineering required to establish actual budget cost estimates and control device effectiveness evaluations. The analyses do not reflect the final engineering basis for development of any of the identified controls. The estimates, however, have been conducted in accordance with MDNR's request using the techniques in USEPA Air Pollution Control Cost Manual (EPA/452/B-02-001) as described below and are rough order of magnitude estimates. Actual engineering design assumptions and resulting costs of the devices may differ from the assumptions made in the below analyses based on facts that exist at the time of decommissioning.

Additionally, based on a review of visibility modeling conducted using US EPA modeling platforms by the US EPA[1], the Midwest Ozone Group (MOG) and the Lake Area Director's Consortium (LADCO), visibility in Class I areas in the Midwest and eastern states will likely meet the required visibility glidepath goals during the 2028 planning horizon. Accordingly, as described more fully herein,

[1] US EPA Technical Support Document for EPA's Updated 2028 Regional Haze Modeling Page 25, Table 3-3: https://www.epa.gov/sites/production/files/2019-10/documents/updated_2028_regional_haze_modeling-tsd-2019_0.pdf

additional controls on the Rush Island Energy Center units are not warranted based on modeling projections, the costs identified for additional controls, and the other relevant factors. .

II. Rush Island Site Description

a. Unit Information

Rush Island Energy Center consists of two pulverized coal, dry bottom, tangentially fired boilers (B-1 and B-2) which began construction in June 1971. Boilers 1 and 2 have the same design rating (5,922 MMBtu/hr) and nameplate capacity (621 MW).

Ameren uses a combination of emission control strategies on the Rush Island Energy Center EGUs to minimize emissions of regulated pollutants including add on controls, lower emitting process and the use of lower emission fuels. Both units are equipped with electrostatic precipitators (ESPs) for the control of Mercury (Hg), particulate matter (PM) and non-Hg metals. These controls enable Ameren to meet MO state implementation plan (SIP) requirements in the PM SIP for protection of the PM National Ambient Air Quality Standard (NAAQS) as well as the more stringent maximum achievable control technology requirements for Hg and non-Hg metals (PM surrogate) of the Mercury and Air Toxics Standards Rule (MATS).

NOx emissions are controlled from Units 1 and 2 via a combination of low NOx burners (LNB), over-fire air (OFA) and neural network optimization. The neural network optimization system combined with the LNB and staged combustion from separated over-fire air systems optimizes the reductions possible from these combustion controls. Additional reductions are not possible via further optimization. Additional NOx reductions from adding additional over-fire air systems to further stage construction are believed to have limited benefit as a result of the significant amount of staging already occurring. Through this combination of NOx controls, Ameren has achieved industry leading NOx control levels in the absence of post combustion controls. Ameren consistently achieves NOx emission rates at the Rush Island Energy Center EGUs under 0.10 lbs. NOx per million Btus of heat input without the significant added costs of employing selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) technology.

The control of sulfur oxides is accomplished at the Rush Island Energy Center by combusting very low sulfur coals. Ameren currently combusts some of the lowest sulfur coals available on the market. Ameren as a fuel procurement strategy designed to sustainably maintain its supply of low sulfur coals while also minimizing the cost of those fuels. Additional reductions from the purchase of even lower sulfur coals are not expected to be available or sustainable on an ongoing basis.

The above control strategies all combine together to effectively control emissions from the boilers. Because of the already low emission rates at the Rush Island EGUs additional emission control will have a lower overall impact.

b. Remaining Useful Life

Ameren recently released its 2020 Integrated Resource Plan (IRP) with a commitment to transition its generation fleet to a cleaner and more diverse portfolio. The plan includes the addition of 3,100 megaWatts (MW) of wind and solar generation resources by 2030. The plan also includes the retirement of all Ameren coal fired generation by 2042 and the retirement of Meramec Energy Center in

2022 and the retirement of the two Sioux Energy Center EGUs in 2028. The retirement of the Rush Island Energy Center EGUs is also included in the 2020 IRP. The Rush Island Energy Center EGUs are scheduled for retirement in 2039 as outlined in the 2020 IRP.

The remaining useful life of emission units is considered in two ways under Regional Haze guidance. Remaining useful life must be taken into account as it is impacted by the time required for the installation of controls on a unit and as it affects the cost effectiveness of the controls on a cost per ton of emission reduction basis. The planned retirement of emission units within the Regional Haze planning horizon can be taken into account by states when developing a Regional Haze SIP. Units that will retire before the end of the planning horizon (2028) can avoid the analysis of all four factors.

Remaining useful life also affects the cost effectiveness of any installed controls. Cost effectiveness of a control is determined based on the capital costs and the annual operation and maintenance costs annualized for the life of the control device or the life of the emission unit whichever is less. The period of annualization is the difference between the date a control device can be constructed and the retirement date of an emission unit (or the control device whichever is less).

Impacting the amount of time for annualizing those costs is the time required for the installation of controls. This time includes the planning, engineering, and permitting time required along with the actual purchasing and construction of the control device. These processes can take many years in combination after the state implementation plan is finalized which may push the operation of any new control device to 2028 or beyond. The time for installation of the different control devices evaluated in this document have been taken into account based on the best information and belief.

The amount of additional time for the construction of a new emission control devices lowers the overall useful life of the added control equipment. While normally new control equipment may have 30 or more years of useful life, any added controls at Rush Island would have a reduced lifespan because the retirement dates for the Rush Island EGUs are less than 30 years away based on the 2020 IRP retirement date of 2039 for Units 1 and 2. This reduced lifespan increases the annualized cost because the total capital investment cost is annualized over a lower number of years.

Changes in the annualization period has a large effect on the cost per ton of emission reduction. Decreases in the annualization period decrease the cost effectiveness of the control device by increasing the cost per ton of emission reduction making the installation of the control less beneficial.

It should also be noted that the time for the construction of the emission controls estimated in this analysis assume that only controls at Rush Island Energy Center are required. Should emission controls be required at multiple energy centers, the time for construction would most likely be extended as multiple large construction projects at multiple facilities requires additional coordination for engineering services, construction services and equipment procurement. For this reason, the times for construction are underestimated should multiple facilities be impacted by the Regional Haze SIP and the cost estimates would thereby be underestimated as well.

c. Site Specific Conditions Affecting Installation of Controls

An additional factor to consider is the physical ability to add additional control devices to the units. When the Rush Island site was designed, equipment was laid out to achieve the best operation while keeping a small footprint for the site. Over time, changes to the layout have been made to improve the effectiveness of controls and to meet new regulatory requirements such as the MATs Rule and the Coal Combustion Residuals rule. These changes include the construction of new ductwork and ESP boxes on Units 1 and 2 and the installation of the material handling equipment and wastewater equipment necessary to meet the requirements of dry ash handling contained in the CCR rule. These changes along with the already congested layout creates problems for designing the layout for new emission control devices which take up a large amount of space. This can create problems when new emission control devices which take up a large amount of space need to be added. Rush Island has a very cramped equipment layout with little extra room to install new, unplanned equipment or buildings. If new equipment needs to be added, significant rework will need to be performed including changing the layout of the ductwork. Additional booster fans may be needed along with major upgrades needed for the auxiliary power supply.

III. USEPA Air Pollution Control Cost Manual

a. Equation Limitations

The USEPA Air Pollution Control Cost Manual[2] (the Manual) provides very rough order of magnitude estimates of the cost to install and operate air pollution controls at a site. Using the methods and cost equations in the manual can produce inaccurate results depending on the situation. The estimations being used are very much generalized and will not show the actual costs that Rush Island would incur due to the installation of additional emission controls. The manual itself indicates that the rough order of magnitude estimates are only “nominally accurate to within +/- 30 percent”.

Error will also occur at higher rates for cost estimations where the sample size from the original studies that helped develop the Manual were small. Specifically, this can occur when estimating pricing for controls not normally placed on units of certain MW sizes or emission rates. The Manual specifically points out that dry flue gas desulfurization (FGD) systems typically are not installed on larger combustion units. Using generalized equations to estimate costs on installing control devices for non-normal situations will produce values that are not representative of actual site-specific costs or emission reductions that would be achieved. Ameren recommends that MDNR rely both on previous actual site-specific studies performed along with the values produced using the equations in the Manual.

There are also certain default cost values that appear in the example equations for Direct Annual Cost calculations that are not representative of actual costs Ameren would incur. Examples of these default costs are the costs to purchase a ton of limestone, the costs for electricity and make-up water, and the cost for waste disposal. These estimates utilize relevant unit cost data obtained from actual operation data or prior performed studies when available instead of the default values in the Manual.

In addition, part of its risk mitigation and regulatory planning processes, Ameren has over the years developed high-level capital cost estimates for some of these control strategies with respect to various regulatory proposals. These estimates have been included in this evaluation for comparison to the values estimated using the Manual. Such estimates, however, are not based on detailed engineering and do not include the allowance for funds used during construction (AFUDC) costs removed from the

[2] Available at https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution

total capital costs to better align with the Control Cost Manual "overnight" estimation calculation method.

b. Chapter Revision

Another limitation with the cost estimations is that Section 5, Chapter 1 of the Manual on SO_2 and Acid Gas Controls is currently in draft form. A revision to Section 5, Chapter 1 of the Manual was proposed in July 2020 and is currently under public comment period. Even though the July 2020 publication is still under review, this version was used to estimate the SO_2 control cost instead of the previous version published in December 1995. The use of the draft Section 5 of the control manual was recommended by footnote 63 of the EPA document "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period." Because Section 5, Chapter 1 of the Manual is still in draft and subject to change, the basis for the SO_2 control technology estimates in the draft manual, including the assumptions and equations, may contain errors. Because they are not finalized and may contain errors, the use of the draft Section 5 as recommended by USEPA guidance on Regional Haze SIP development may result in inaccurate estimations for control costs. In order to better justify these estimates, they have been compared to site specific engineering cost estimates developed for Ameren.

A noted concern with the draft Section 5 of the EPA Control Cost Manual is the spray dry absorber (SDA) estimation procedure appears to be missing a retrofit factor in the equations for the total capital cost for larger units. A retrofit factor is used in estimates for other controls like wet flue gas desulfurization, selective catalytic reduction (SCR), etc. In the draft Section 5, USEPA has broken out the capital cost equations for the SDA depending on the unit size and USEPA includes a retrofit factor in the capital cost equations for SDA installation on smaller EGUs. The Manual recommends using a different equation if your unit size is greater than 600 MW. However, like the Manual indicates, installing Dry FGDs on larger units is uncommon. Creating equations to estimate prices for larger units will most likely have a higher chance of error because of limited example cases. Despite this concession by USEPA, one notable factor is absent in the cost estimation equation for large units. The cost equation for large units greater than 600 MW does not include a built-in retrofit factor when calculating Total Capital Investment even though the larger units will have the same if not greater retrofit issues that smaller units will have. Further along in the procedure a retrofit factor is included in the denominator for the calculation of annual maintenance costs. The inclusion of this factor in the denominator appears to assume that a retrofit factor was applied to the Total Capital Investment and needed to be removed to estimate the annual maintenance cost.

If the greater than 600 MW equation is used as it currently is written, the retrofit factor never gets applied to the Total Capital Investment. As stated in the Manual, retrofit factors are recommended for use in the cost estimations for sites requiring more difficult installations. Leaving the retrofit factor out of the equation for larger units appears to be an error in the draft Section 5 TCI equation for large SDA installations. To correct for this error, Ameren has added in the retrofit multiplier to the SDA total capital cost for the greater than 600 MW equation from the Manual.

c. Retrofit Adjustments

The Manual allows for the use of retrofit adjustments for existing sites with conditions that lead to higher costs to retroactively install emission controls. Under the procedures in the Manual, higher retrofit factors should be used for congested sites as costs can vary from site to site depending on the complexity of installing new equipment in an existing facility. As discussed in section 2, Rush Island has a higher cost to fitting in additional controls because of limited space and the large amount of rework required for the ductwork and additional necessary current equipment upgrades that would need to occur to handle the operation of additional controls. These units were constructed 45 years ago, with little consideration to providing areas to accommodate future modification and plant additions. The site is constrained by the river on one side, the "close-coupled" coal pile, reclaim and receiving systems and coal rail loop, and switchyard operational area. Only one side of the plant may be practical for retrofits. For the following reasons, the retrofit factor for Rush Island has been increased to 1.5 for SO_2 controls, and 1.2 for SCR NOx control indicating the retrofits will be more complicated than average:

- Retrofits requiring very long runs of flue gas ductwork will be made high over existing equipment. The height will require extensive structural steel and foundations that meet current wind and seismic design loads. The cost of this structural work, including reinforcement due to the new additional loads, will be significant.
- New controls would potentially require relocation of buildings and equipment. Some equipment, piping, and bus ducts are underground, adding significant cost.
- The electrical power requirements for new controls can be quite large and existing power sources in the plant are not adequate. Getting the required power directly from the switchyard adds significant costs.
- Some controls will add enough pressure resistance to the draft systems that will require the installation of new and/or booster fans. The installation of this equipment in areas with limited space will increase costs, along with the additional power needs to run the equipment.
- Scheduling of control equipment installation for multiple units and coordinating with other maintenance occurring during outages will be a challenge, especially given the limited number of craft labor available nationally to perform these installations. The Manual specifically asks for costs itemized in formulas to be considered without adding in significant cost adjustments for labor due to overtime or premium pricing for specialized technicians. The retrofit factor is used to account for these premium labor factors.

d. Inflation Adjustments

Values in the Manual have also been adjusted for inflation. The Manual provides a model with equations to estimate the cost of SO_2 and NOx controls based on 2016 dollars and have been adjusted for inflation in this evaluation. Section 1, Chapter 2 of the Manual under section 2.5.3 recommends adjusting for inflation only to the date that the cost estimate is prepared and not escalated to a future year. Ameren utilized a 2% per year inflation adjustment for the cost estimates in this document as recommended by USEPA in the Manual. All values have been adjusted to 2020 dollars.

IV. SO_2 Control Technologies

a. Feasible Options

While most of the listed control options in the MDNR data request letter are technically "feasible" for use on coal boilers, many of them are not normally used on larger sized boilers and would not be cost effective or control emissions efficiently. Units 1 and 2 at the Rush Island Energy Center currently combust western sub-bituminous low sulfur coals which already greatly reduces the SO_2 emission rate. Wet FGDs are the more common post combustion SO_2 control utilized on larger boilers like Rush Island Units. Dry Sorbent Injection (DSI) systems have also been used for SO_2 controls, but it is less commonly used for larger boilers. Ameren has previously performed rough order of magnitude cost studies on both Wet FGDs and DSI installation and operation costs and those cost estimates are presented in the discussion below. The capital cost values have been altered from the study to remove out AFUDC costs as required by the Control Cost Manual to fit the "overnight" estimation method. The values have also been adjusted for inflation to 2020 dollars amounts.

b. Cost Calculations

Section 5, Chapter 1 of the USEPA Air Pollution Control Cost Manual was used to evaluate add on SO_2 control technologies at the Rush Island Energy Center for capital costs, annual operating and maintenance costs, and the annualized costs and the cost effectiveness for removing emissions. While the Manual mentions a few different available SO_2 control technologies, it only performs an extensive review with cost equations for Wet Limestone FGDs and Lime Spray Dry Absorbers. Ameren has used the equations in the Manual to perform cost estimations for the installation and operation of both technologies. These values are also compared to previous cost estimation studies that Ameren has performed in the past for Wet FGD as well as costs for Dry Sorbent Injection (DSI) control systems.

While DSI costs are not detailed in the Manual, they are provided here for comparison to other SO_2 control technologies. It should be noted that the costs detailed in the Ameren studies are based on the average cost for installation of the same technology on each of the four (4) EGUs. Significant cost savings associated with engineering, procurement, project management, construction management are inherent in those estimates. Conversely, the capital costs for installation of these technologies on a single unit or pair of units are likely underestimated because of this. In other words, the annualized cost per ton of emission reduction for installing Wet FGD on just Unit 1 (or any single unit) is likely higher than shown in Table 3 because cost efficiencies assumed for multi-unit installations will not be possible. Tables 1 through 3 show the results from the analysis of both SO_2 control technologies.

Table 1: SO_2 Estimated Emission Reductions

Control Equipment Type	Rush Island Boilers	Baseline Emission Rate (lb/mmbtu)	Control Rate (lb/mmbtu)	Control Effectiveness (Percent Reduction)	Annual Emissions Reduction (tons/year)
Wet FGD	B1	0.51	0.05	90%	8,291
	B2	0.51	0.05	90%	8,291
SDA	B1	0.51	0.06	88%	8,111
	B2	0.51	0.06	88%	8,111

Table 2: SO_2 Estimated Control Costs using EPA Air Pollution Control Cost Manual Equations

Control Equipment Type	Rush Island Boilers	Capital Costs	Annual Operating and Maintenance Costs	Annualized Costs	Cost Effectiveness (cost/removed ton)
Wet FGD	B1	$430,282,054	$12,938,443	$66,225,008	$7,988
	B2	$430,282,054	$12,938,443	$66,225,008	$7,988
SDA	B1	$376,653,888	$10,962,825	$57,583,739	$7,100
	B2	$376,653,888	$10,962,825	$57,583,739	$7,100

Table 3: SO_2 Estimated Control Costs using Previous Ameren Studies

Control Equipment Type	Rush Island Boilers	Capital Costs	Annual Operating and Maintenance Costs	Annualized Costs	Cost Effectiveness (cost/removed ton)
Wet FGD	B1	$422,280,000	$7,560,000	$59,741,415	$7,206
	B2	$422,280,000	$7,560,000	$59,741,415	$7,206
DSI	B1	$71,338,000	$15,688,000	$23,512,656	$5,116
	B2	$71,338,000	$15,688,000	$23,512,656	$5,116
DSI with Fabric Filter	B1	$139,358,000	$21,963,200	$37,248,579	$5,822
	B2	$139,358,000	$21,963,200	$37,248,579	$5,822

As discussed above, Units 1 and 2 at the Rush Island Energy Center burn very low sulfur coals as a control strategy to reduce SO_2 emissions. As shown in Table 1, the baseline SO_2 emissions rates are already relatively low prior to the evaluation of additional post-combustion SO2 controls. The potential reduction in SO_2 emissions resulting from adding post-combustion control devices, such as Wet Scrubbers, SDAs, or DSI, is significantly lower for the Rush Island Energy Center EGUs when compared to similar coal fired emission units that do not burn low sulfur fuel. This lower potential for emission reductions results in higher costs of removal on a per ton of emission reduction basis.

Table 2 shows the estimated capital costs, annual operating and maintenance costs, and the annualized costs using the procedures in the Manual and the remaining useful life of the units from the 2020 IRP. The Rush Island units are currently scheduled for retirement by the end of 2039. This early retirement of the units further increases the estimated emission removal costs because the units are planned for shutdown prior to the full life of the control equipment. Per the procedures in the Manual, Wet Scrubbers and SDAs have an estimated control life of 30 years which is longer than the remaining life of the plant so the annualization period is based on the difference between the estimated date of operation for the control and the retirement date. Ameren has taken into account the time it takes for planning, engineering, permitting, purchasing, construction, installation and initialization of the controls. Based on this, Ameren has determined that for Wet FGD and SDA controls, the estimated date of operation, assuming MO SIP approval by 2023, would be 2028 for an annualization period of 11 years.

For DSI controls, the estimated date of operation would begin in 2026 for an annualization period of 13 years.

Studies previously performed by Ameren on Wet Scrubbers show similar total capital cost amounts when compared to cost estimations using the equations in the Manual. While estimated calculations were performed for the SDA installation and operation based on the Manual equations, Ameren has not had site specific studies performed for SDA costs. This is mainly due to the fact, as stated in the Manual, that Dry FGD's are not a normal option for SO2 emission reduction for units of Rush Island's size. Nevertheless, the cost estimations still show that the cost for one ton of removal is relatively high for this scenario.

When using the Control Cost Manual equations, default values were updated to better estimate actual predicted costs for Rush Island and the retrofit value was also increased to reflect the increased difficulty of the installation at the already congested site. The capital cost, direct annual costs, and annualized costs are estimated to be the same for either unit. Ameren believes the cost to remove one ton of SO_2 emissions with either an added on Wet FGD or SDA exceeds the reasonable cost of compliance which is one of the four factors in determining potential control measures for the State Implementation Plan.

While DSI calculations are not performed in the Control Cost Manual, Ameren had previously performed studies to determine the capital cost and annual operating costs of a DSI system at Rush Island. Table 3 shows the cost for the installation of a DSI system both with and without a Fabric Filter. The addition of a Fabric Filter increases the SO_2 removal efficiency from 50% to 70%, however the cost effectiveness is worse because of the increased capital cost. DSI systems used as the main control measure for SO_2 are not normally installed on units of Rush Island's size. The manual indicates that in 2018, only 17 power plants were using DSI to control SO_2 further indicating that this is not a common method for SO_2 removal. Even though the cost to remove one ton of emissions appear to be lower with DSI, the lower removal efficiency of SO_2 decreases the total overall tons of SO_2 removed which causes the addition of a DSI system to have a much lower impact on visible emissions.

c. Evaluations of FGD Technologies

Flue gas desulphurization technologies are generally classified as once-through or regenerative, and each of these can be further classified as wet or dry systems. Regenerative systems have higher capital costs than once-through systems because of the additional required process equipment to separate and dry the recovered salts. The vast majority of installed FGDs are once-through, and while most wet FGDs utilize limestone as the reagent, there are variations such as those below that are characterized by the reagents utilized. There are advantages and disadvantages of each technology, but in general the major equipment is very similar resulting in similar costs, and each technology can achieve high SO_2 removal rates. Detail studies of each technology would be required to determine the capital and operating costs for each specific unit application.

Section 5, Chapter 1 of the Manual includes cost equations for Wet Scrubbers using limestone as a reagent and SDAs with a lime reagent but does not include costs for other SO_2 control technologies. It does provide some relative cost information on other control technologies based on limited information on actual costs from plants that have installed the technology. The Manual indicates that Wet Scrubbers using lime have higher costs than limestone systems due to the higher purchase price cost of lime. The average controlled emission rate is also lower for limestone than lime-based systems as seen in Table 1.2 in Section 5 of the Manual. The higher operating costs and higher average controlled emission rates for lime systems indicates that the cost per ton of SO_2 reduction for a wet lime scrubber system would be higher than that of a limestone system.

The Manual does not include cost equations for Circulating Dry Scrubbers (CDS), however, it does indicate that the capital costs for a CDS system are similar to the SDA system for combustion units of the same size and emission rates. Table 1.2 in Section 5 of the Manual also indicates that the average emission rates for units with SDAs are lower than units with CDS installed. If units with SDAs have lower emission rates, but similar pricing, CDS cost to remove one ton of emissions would be higher than SDAs, making the evaluation of CDS costs unnecessary.

Magnesium Enhanced Lime (MEL) FGDs and Dual Alkali FGDs are both wet FGD systems. The absorber equipment may be smaller than a limestone Wet FGD, but the sorbent cost is significantly higher, making these control technologies not commonly used in the power industry. Table 1.1 in Section 5 of the Manual indicates that in 2018 only 4 Dual Alkali systems were installed at U.S. Power Plants. Dual Alkali systems also show similar SO_2 emission rates when compared to limestone FGD systems as shown in Table 1.2 in Section 5 of the Manual.

d. Evaluations of Other Technologies

Integrated Gasification Combined-Cycle (IGCC) is a very high capital cost technology and retrofitting an existing coal plant of Rush Island's size would be very challenging and not economical. While theoretically, some systems like coal handling, water treatment, and steam turbines could be reused, they are spread out drastically over a large area as compared to a "green field" IGCC site making connecting these systems difficult. Trying to incorporate existing equipment could detrimentally influence the design and cost. The gasification plant, gas turbines, and heat recovery steam generators would require new locations on an already very congested site likely being very remote from the existing boiler building, again resulting in long runs of process lines between components. U.S. experience with reliability of the coal gasification process has not been good, and back-up natural gas for this technology would be very costly. We are currently not aware of an IGCC retrofit for an existing coal plant of Rush Island's size.

Hydrated Ash Reinjection, Fuel Switching, and Coal Cleaning are also not optimal SO_2 control technologies for Rush Island Units. Hydrated Ash Reinjection involves the improvement of lime sorbent utilization by the recirculation of the boiler's ash. This technology is more applicable for fluidized bed boilers, not pulverized coal boilers where there is no lime usage. Rush Island is already burning 100% Power River Basin (PRB) coal, some of the lowest sulfur coals in the country. In addition, these units are typically burning coal from the individual mines and seams with some of the lowest sulfur contents within the PRB. Fuel switching is not reasonable because of the already low sulfur fuel being combusted. Coal cleaning is also more effective for coals where much of the sulfur is inorganic pyrite. Most of the sulfur in PRB coals are part of an organic compound and are less affected by coal cleaning. Because of the already low sulfur content of the coal and organic type of sulfur in the coal, coal cleaning to remove additional sulfur would be less effective and the costs unjustifiable when compared to sites using higher sulfur content coal.

V. NOx Control Technologies

a. Existing NOx Controls

As discussed above, Ameren minimizes NOx emissions at Units 1 and 2 at the Rush Island Energy Center using a combination of low NOx burners, separated overfire air and neural network optimization. These technologies operate continuously while the boilers are in operation to prevent NOx from being generated in the combustion process. The LNB and OFA systems combine to delay the mixing of air and fuel to reduce and prevent the formation of thermal NOx and to complete fuel combustion in a lower temperature portion of the furnace to further reduce NOx emissions. These systems combined with an artificial intelligence neural network that learns and adjusts operational settings to optimize combustion (i.e., produce the lowest NOx emissions in the safest manner), along with burning 100% western sub-bituminous coal (lower nitrogen content to reduce fuel related NOx) have made these units some of the lowest NOx emitting coal-fired boilers in the country. Additional reductions in NOx from this combination of technologies is not believed to be achievable. These combustion control technologies operate continuously while the boilers are in operation and operate at an already optimized emission rate of 0.08 lb/mmBtu based on 2017-2019 operational data. Considering the uncontrolled NOx emission rate for tangentially fired boilers from AP-42 Table 1.1-2 is 8.4 lb/ton, and a subbituminous coal heat content of 17.5 mmBtu/ton, the uncontrolled NOx emission rate of the boilers would be 0.48 lb/mmBtu. With existing LNB and OFA controls, Rush Island already achieves 83% NOx control, among the lowest emission rates for coal-fired plants with no post-combustion controls.

b. Feasible Options

Both Selective Catalytic Reduction (SCR) systems and Selective Non-catalytic Reduction (SNCR) systems are feasible technologies for the Rush Island Energy Center EGUs because they have been installed and operated successfully at other coal-fired EGUs. Similarly, flue gas recirculation (FGR) and low excess air are also feasible technologies, however, the current use of low NOx burners and separated overfire air are similar technologies as FGR and low excess air and are believed to be both incompatible with and less effective than the existing technologies used to minimize NOx from Units 1 and 2.

c. Cost Calculations

SCR and SNCR technologies were evaluated following the methods of EPA's Air Pollution Control Cost Manual, Section 4, Chapters 1 and 2.

The evaluation of SCR controls following the procedures in the Manual uses a combination of plant-specific operation characteristics and default choices to estimate the potential reduction in annual NOx emissions, the total capital cost of construction, and the annualized cost of operation for the control. The SCR calculation includes the choice of outlet NOx emission rate. For the calculations below, the outlet NOx rate of 0.04 lb/mmBtu is chosen based on the cost manual Chapter 2, section 2.3.5, indicating that the NOx outlet should not be set less than 0.04 lb/mmBtu without a vendor guarantee. Since this analysis did not obtain specific vendor information, outlet NOx rates below this level are inappropriate.

Plant specific inputs are used in the SCR control cost tool, to fill in missing data or in place of defaults for the following tool inputs:

- o Boiler MW rating at full load capacity
- o Estimated actual megawatt hours output
- o Net plant heat input rate in mmBtu/MW
- o Sulfur content of fuel
- o Number of days the SCR operates
- o Number of days the boiler operates
- o Inlet NOx in lbs/mmBtu
- o Outlet NOx in lbs/mmBtu
- o Number of chambers
- o Number of catalyst layers
- o Number of empty catalyst layers
- o Gas temperature at inlet
- o Estimated equipment life in years

Table 4 resulting emission reductions are regardless of reagent chosen, either ammonia or urea. Table 5 resulting cost effectiveness estimates vary based on the reagent chosen.

Table 4: NOx Estimated Emission Reductions using EPA Air Pollution Control Cost Manual Equation

Rush Island Boilers	Control Equipment Type	Baseline Emission Rate (lb/mmBtu)	Control Rate (lb/mmBtu)	Control Effectiveness (Percent Reduction)	Annual Emissions Reduction (tons/year)
B1	SCR	0.08	0.04	50%	759
B2	SCR	0.08	0.04	50%	759

Table 5: NOx Estimated Control Costs using EPA Air Pollution Control Cost Manual Equation

Rush Island Boilers	Control Equipment Type	Capital Costs	Annual Operating and Maintenance Costs	Annualized Costs	Cost Effectiveness (cost/removed ton)
B1	SCR - Ammonia	$202,626,984	$2,778,794	$25,021,508	$32,965
B2	SCR - Ammonia	$202,626,984	$2,778,794	$25,021,508	$32,965
Rush Island Boilers	Control Equipment Type	Capital Costs	Annual Operating and Maintenance Costs	Annualized Costs	Cost Effectiveness (cost/removed ton)
B1	SCR- Urea	$202,626,984	$2,827,832	$25,070,545	$33,030
B2	SCR- Urea	$202,626,984	$2,827,832	$25,070,545	$33,030

The evaluation of SNCR controls according to the manual is not possible since page 1-41 states that "... the cost equations are sufficient for NOxout emission levels as low as 0.08 lb/mmBtu for FB and 0.1 lb/mmBtu for non-FB." Rush Island is not a FB, or fluidized bed, boilers so the equations in the manual are only sufficient for outlet NOx rates down to 0.1 lb/mmBtu. Rush Island currently emits at 0.08 lb/mmBtu, less than the 0.1 outlet concentration rate that the cost equation can estimate. From the Manual Section 4, Chapter 1, Figure 1.1c, SNCR NOx Reduction Efficiency Versus Baseline NOx Levels for Coal-Fired Utility Boilers, at inlet NOx concentrations below 0.2 lb/mmBtu, there are no datapoints from which to estimate NOx reduction efficiency. Extrapolating from the regression line, emission reductions of less than 20% may be expected for inlet NOx near 0.08 lb/mmBtu where Rush Island currently emits with LNB and OFA. With the period 2017-2019 averaging 3,000 tons of NOx per year, the largest NOx reduction that could be expected is 600 tons per year with SNCR, with a more reasonable expectation of 450 tons per year based on 15% control efficiency.

To estimate the annualized cost in a methodology similar to the COST manual, the total capital cost of installing SNCR is estimated first, then the total capital costs are spread over the years of operation to estimate annual capital cost. Then the COST manual estimate of 25% capital cost and 75% operating costs are used to estimate total annual costs. The total annualized costs are then divided by the tonnage reduced to estimate cost effectiveness of SNCR.

The COST manual cites a NESCAUM study from March 7, 2005 on BART controls (http://www.nescaum.org/topics/regional-haze/regional-haze-documents) for an approximate utility capital cost of SNCR at $10 to $20 per kw. Costs are increased from 2005 dollars to 2020 by increasing 2% per year for 15 years, consistent with other cost estimates in this document. The total capital cost per unit is then divided over the remaining lifetime of each unit, and facility total annual capital cost is estimated at $1,863,000 in Table 6. The COST manual SNCR chapter states "A typical breakdown of annual costs for utilities is 25% for capital recovery and 75% for operating expense." With annual capital costs of $1,863,000, operating costs should be around $5,589,000, and the total annual costs (capital recovery and operating).

Table 6: SNCR Cost Estimate

Capital Cost Range Singe Unit	Base Load (MW)	Base Load (kw)	Total Capital Cost per unit: Estimated $15 per kw	
			2005 dollars	2020 dollars
B1	621MW	621,000 kw	$9,315,000	$12,109,500
B2	621 MW	621,000 kw	$9,315,000	$12,109,500
Capital Cost Combined Units	Remaining Lifetime After Construction	Annual Capital Cost in 2020 Dollars	Annual Operating Cost in 2020 Dollars	Annual Total Cost
B1	13 years	$931,500	-	-
B2	13 years	$931,500		
Plant Total		$1,863,000	$5,589,000	$7,452,000

With annualized total cost estimated over $7.4 million at Rush Island for SNCR that achieves 15% control efficiency and 450 tons of NOx reduced annually, the cost effectiveness estimated over $16,500/ton. SNCR is not a cost-effective option at Rush Island due to already low NOx rates, little possible additional emission reductions, and capital cost recovery timeframes of only 13 years with established unit lifetimes.

d. Evaluations of Other Technologies

Low excess air technology is premised on lowering the amount of air (and its inherent nitrogen content) used for the combustion of coal in the furnace. As mentioned above, these units are already being operated at the lowest possible amount of air to safely and completely combust all of the coal.

Flue gas recirculation technology separates a small amount of flue gas from the boiler, typically from the boiler exit, and recirculates the flue gas back into the furnace to lower the flame temperature. This is a common technology on smaller gas and oil fired units where duct runs are shorter, however, it is of limited value for larger coal fired EGUs. As mentioned above, these units already have significant staging of the combustion process resulting in a significant reduction of combustion temperatures. We are currently not aware of any large pulverized coal units utilizing this technology.

VI. Additional Impacts to Implementing New Controls

a. Air Quality Permitting

Permitting a new control device will require a construction permit from the Missouri DNR Air Pollution Control program. Construction permits are charged a flat fee based on type, between $250 and $5,000, and an hourly rate of $75. A rough estimate of 100 hours for a permit leads to a permit cost above $7,500. The time to obtain the necessary permits is likely 12 months, adding to the time to implement the controls.

The COST manual introduction chapter describes the basic methodology for cost estimates, placing the permitting costs under indirect costs. Indirect costs are those borne by the facility even if the control equipment is not in continuous operation. Permitting costs are considered indirect costs, like property taxes, insurance, and administrative charges. However, the methodology outlined in the introduction and specific control chapters do not explicitly include permitting costs directly, either as a separate item or item included in the general percentage factor added to the total administrative cost. When an approximate one-time permitting cost of $7,500 is added to the administrative costs, the total cost effectiveness changes by less than $3/ton which is negligible. A more pressing concern is any time above 12 months to obtain a permit, which would decrease the lifetime of the control by a year. Changing the lifetime of controls can change cost effectiveness by $500/ton or more, so the permit issuance timing should be considered a more significant factor in overall cost effectiveness.

b. Waste Impacts

NOx controls typically do not significantly alter the characteristics of the fly ash other than the deposition of ammonia sulfates in the fly ash. Ammonia content greater than 5 ppm can result in off-gassing, which would impact the salability of the ash as a byproduct, and excess ammonia will also impact the storage and disposal of the ash by landfill. SCR catalysts are not typically considered a hazardous waste once they can no longer be recycled or reused and can be disposed of in an approved landfill.

Wet FGD systems allow the recovery of salts in the form of gypsum, which can be sold as a byproduct or landfilled. Dry scrubber systems generally consume less water and require less waste processing, however the waste generated from a dry scrubber contains metals and is considered hazardous waste. The generation of hazardous waste comes with significant costs to ship the waste offsite and disposal costs in an approved landfill.

c. Water Impacts

For NOx controls, the deposition of ammonia salts on the catalyst may require additional acid washing to remove deposits if air and steam blowing are not sufficient to prevent buildup. Excess wastewater generated from acid washing must be disposed of and treated by the plant.

Dry FGD systems require additional water that is sprayed into the absorber to cool the flue gas to the proper temperature for the chemical reaction. Wet FGD systems require additional water that is mixed with the alkali reagent to form the sorbent that is injected in the flue gas stream. Either wet or dry desulfurization systems will have additional water needs compared to existing plant controls. The processing of gypsum from a wet FGD system requires the waste slurry collected in the absorber to be filtered and then dewatered before being sent off site. The slurry wastewater treatment also includes an increase in pH to precipitate metals and potential additives to promote coagulation and flocculation.

d. Risk Management Plans

The Clean Air Act Section 112(r) requires risk management plans for facilities that use extremely hazardous substances. These plans are site-specific and must be revised and resubmitted to EPA every 5 years. For either SCR or SNCR that uses ammonia as the reagent, the cost manual recommends onsite storage concentration of 29%, above the RMP threshold of 20% concentration. The onsite storage of ammonia at 14 days or more is also over the 20,000 lb regulated substance RMP threshold. Formulating the plan, onsite monitoring and reporting, and minimum annual coordination with local emergency planning and response agencies represent significant administrative costs that the cost manual does not attempt to estimate or include.

Based on past plans of similar complexity created by Ameren, an estimate of plan initial design will take a total of 165 hours of engineering, reviews and administrative work, for a total of $19,250. A single year of annual monitoring, reporting, and meetings with emergency management personnel will take 218 hours for a total of $27,250. These costs are not included in the estimates above and they increase the cost effectiveness totals by less than $10/ton.

VII. Conclusion

The cost estimates and evaluations developed in this response are based from either the USEPA Air Pollution Control Cost Manual or previous studies performed by Ameren. The Manual states that equations may have up to 30% error and some of the studies performed by Ameren are many years old so actual costs may be higher or lower than the current estimates. Calculations were performed for Wet FGD, SDA, SCR and SNCR installations and operation using information from the Manual. Cost estimates were also provided for Wet FGD and DSI additions using previous Ameren order of magnitude studies. The cost estimates show the high cost of adding post combustion control technology to Units 1 and 2 at the Rush Island Energy Center based on USEPAs methodology and supported by Ameren's order of magnitude engineering cost estimates.

The estimated cost per ton of emission reduction for post combustion SO_2 controls ranges from \$5,100 to \$5,800 per ton for DSI to \$7,100 to \$8,000 per ton for SDA or wet FGD controls. The estimated cost per ton of emission reduction for post combustion NOx controls are even higher and range from \$32,000 to \$33,000 per ton of NOx reduction. These costs are higher than previously determined to be cost effective.

Importantly, US EPA modeling platforms indicate that the glidepath for the Midwest and Eastern states are likely to achieve both the 2028 planning goals without the need for additional controls as well as the Regional Haze Rule Goals of obtaining natural visibility conditions by 2064. Also, the reduction in emissions from the addition of emission controls at Ameren are unlikely to have a noticeable change in visibility which is the overall purpose of the Regional Haze Rule. Because of the unreasonably high emission removal cost and EPA modeled compliance projection by 2064, Ameren recommends that the Regional Haze Rule state implementation plan (SIP) for Missouri indicate that the cost for additional emission controls at Rush Island is too high and unnecessary for natural visibility conditions to be met by 2064.

Attachment I: SO_2 Calculation Spreadsheets

Ameren Wet FGD Calculations

Rush Island Wet FGD

Inputs	Source	B1	B2
Full Load Capacity (MW)	nameplate	621	621
Net Plant Heat input rate (MMBtu/MW)	design rate/max load with 5% reduction	10.04	10.04
Max heat input rate (Mmbtu/hr)	design rate	5922	5922
Max annual MW Output	Calc: MW nameplate *8760	5,439,960	5,439,960
Est annual MW Output	Estimated from averaged past air markets data	3780000	3780000
Est time control operates	Estimate from past air markets data	7,332	7,361
Est time boiler operates	Estimate from past air markets data	7,332	7,361
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.695	0.695
SO2 baseline lb/mmbtu	Estimated from averaged past air markets data	0.51	0.51
SO2 Outlet lb/mmbtu	Estimated after control added	0.05	0.05
SO2 Removal Efficiency	Calc (SO2in-SO2out)/SO2 in	90%	90%
SO2 Removed per Hour (lb/hr)	Calc (SO2in * Effic * Max annual heat input rate)	2724	2724
Total SO2 Removed per year (tons)	Calc: SO2 per hr removed * Time control operates/2000	8291	8291
Retrofit Factor		1.50	1.50
Remaining Equipment Life	Based on Construction Time and Remaining Life of Unit	11	11
Number of Additional Personnel	Default from Manual	16	16
Hourly Labor Rate	Default from Manual	60	60
Limestone Cost ($/ton)	Updated based on Ameren specific data	60	60
Make-up water cost ($/gallon)	Updated based on Ameren specific data	0.0063	0.0063
Waste Disposal ($/ton)	Default from Manual	30	30
Electricity Cost ($/kwh)	Default from Manual	0.0361	0.0361
Assumed Interest Rate	Default from Manual (NOx and SO2 sections were different. Using NOx value since SO2 section is still in draft)	5.5%	5.5%

	B1	B2	Total
Capital Cost (2016 $)	$ 398,409,309	$ 398,409,309	
Direct Annual Cost (2016 $)	$ 11,980,040	$ 11,980,040	
Annualized Cost (2016 $)	$ 61,319,452	$ 61,319,452	
Captial Cost (2020 $)	$ 430,282,054	$ 430,282,054	**$ 860,564,108**
Direct Annual Cost (2020 $)	$ 12,938,443	$ 12,938,443	**$ 25,876,887**
Annualized Cost (2020 $)	$ 66,225,008	$ 66,225,008	**$ 132,450,016**
Cost Effectiveness (2020 $/ton)	$ 7,988	$ 7,988	

Ameren Study Cost Estimations	B1	B2	Total
Captial Cost (2020 $)	$ 422,280,000	$ 422,280,000	**$ 844,560,000**
Direct Annual Cost (2020 $)	$ 7,560,000	$ 7,560,000	**$ 15,120,000**
Annualized Cost (2020 $)	$ 59,741,415	$ 59,741,415	**$ 119,482,831**
Cost Effectiveness (2020 $/ton)	$ 7,206	$ 7,206	

Ameren SDA Calculations

Rush Island SDA >600MW

Inputs	Source	B1	B2	
Full Load Capacity (MW)	nameplate	621	621	
Net Plant Heat input rate (MMBtu/MW)	design rate/max load with 5% reduction	10.04	10.04	
Max heat input rate (Mmbtu/hr)	design rate	5922	5922	
Max annual MW Output	Calc: MW nameplate *8760	5,439,960	5,439,960	
Est annual MW Output	Estimated from averaged past air markets data	3780000	3780000	
Est time control operates	Estimate from past air markets data	7,332	7,361	
Est time boiler operates	Estimate from past air markets data	7,332	7,361	
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.695	0.695	
SO2 baseline lb/mmbtu	Estimated from averaged past air markets data	0.51	0.51	
SO2 Outlet lb/mmbtu	Estimated after control added	0.06	0.06	
SO2 Removal Efficiency	Calc (SO2in-SO2out)/SO2 in	88%	88%	
SO2 Removed per Hour (lb/hr)	Calc (SO2in * Effic * Max annual heat input rate)	2665	2665	
Total SO2 Removed per year (tons)	Calc: SO2 per hr removed * Time control operates/2000	8111	8111	
Retrofit Factor		1.50	1.50	
Remaining Equipment Life	Based on Construction Time and Remaining Life of Unit	11	11	
Number of Additional Personnel	Default from Manual	8	8	
Hourly Labor Rate	Default from Manual	60	60	
Lime Cost ($/ton)	Default from Manual	125	125	
Make-up water cost ($/gallon)	Updated based on Ameren specific data	0.0063	0.0063	
Waste Disposal ($/ton)	Default from Manual	30	30	
Electricity Cost ($/kwh)	Default from Manual	0.0361	0.0361	
Assumed Interest Rate	Default from Manual (NOx and SO2 sections were different. Using NOx value since SO2 section is still in draft)	5.5%	5.5%	
	Capital Cost (2016 $)	$ 348,753,600	$ 348,753,600	
	Direct Annual Cost (2016 $)	$ 10,150,764	$ 10,150,764	
	Annualized Cost (2016 $)	$ 53,318,277	$ 53,318,277	**Total**
	Captial Cost (2020 $)	$ 376,653,888	$ 376,653,888	**$ 753,307,776**
	Direct Annual Cost (2020 $)	$ 10,962,825	$ 10,962,825	**$ 21,925,650**
	Annualized Cost (2020 $)	$ 57,583,739	$ 57,583,739	**$ 115,167,477**
	Cost Effectiveness (2020 $/ton)	$ 7,100	$ 7,100	

Ameren DSI Calculations

Ameren Study DSI Costs

Without Fabric Filter

Rush Island

assumed 50% removal efficiency

Inputs	Source	B1	B2	
Full Load Capacity (MW)	nameplate	621	621	
Max heat input rate (Mmbtu/hr)	design rate	5922	5922	
Max annual MW Output	Calc: MW nameplate *8760	5,439,960	5,439,960	
Est annual MW Output	Estimated from averaged past air markets data	3780000	3780000	
Est time control operates	Estimate from past air markets data	7,332	7,361	
Est time boiler operates	Estimate from past air markets data	7,332	7,361	
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.695	0.695	
SO2 baseline lb/mmbtu	Estimated from averaged past air markets data	0.51	0.51	
SO2 Outlet lb/mmbtu	Estimated after control added	0.26	0.26	
SO2 Removal Efficiency		50%	50%	
Assumed Interest Rate	Default from Manual (using NOx section interest rate)	5.5%	5.5%	
Remaining Equipment Life	Based on Construction Time and Remaining Life of Unit	13	13	
Capital Recovery Factor		0.1097	0.1097	
SO2 Removed per Hour (lb/hr)	Calc (SO2in * Effic * Max annual heat input rate)	1510	1510	
Total SO2 Removed per year (tons)	Calc: SO2 per hr removed * Time control operates/2000	4596	4596	**Total**
	Captial Cost (2020 $)	$ 71,338,000	$ 71,338,000	**$ 142,676,000**
	Direct Annual Cost (2020 $)	15,688,000	15,688,000	**$ 31,376,000**
	Annualized Cost (2020 $)	$ 23,512,656	$ 23,512,656	**$ 47,025,311**
	Cost Effectiveness (2020 $/ton)	$ 5,116	$ 5,116	

With Fabric Filter

Rush Island

assumed 70% removal efficiency

Inputs	Source	B1	B2	
Full Load Capacity (MW)	nameplate	621	621	
Max heat input rate (Mmbtu/hr)	design rate	5922	5922	
Max annual MW Output	Calc: MW nameplate *8760	5,439,960	5,439,960	
Est annual MW Output	Estimated from averaged past air markets data	3780000	3780000	
Est time control operates	Estimate from past air markets data	7,332	7,361	
Est time boiler operates	Estimate from past air markets data	7,332	7,361	
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.695	0.695	
SO2 baseline lb/mmbtu	Estimated from averaged past air markets data	0.51	0.51	
SO2 Outlet lb/mmbtu	Estimated after control added	0.16	0.16	
SO2 Removal Efficiency		70%	70%	
Assumed Interest Rate	Default from Manual (using NOx section interest rate)	5.5%	5.5%	
Remaining Equipment Life	Based on Construction Time and Remaining Life of Unit	13	13	
Capital Recovery Factor		0.1097	0.1097	
SO2 Removed per Hour (lb/hr)	Calc (SO2in * Effic * Max annual heat input rate)	2102	2102	
Total SO2 Removed per year (tons)	Calc: SO2 per hr removed * Time control operates/2000	6398	6398	**Total**
	Captial Cost (2020 $)	$ 139,358,000	$ 139,358,000	**$ 278,716,000**
	Direct Annual Cost (2020 $)	21,963,200	21,963,200	**$ 43,926,400**
	Annualized Cost (2020 $)	$ 37,248,579	$ 37,248,579	**$ 74,497,158**
	Cost Effectiveness (2020 $/ton)	$ 5,822	$ 5,822	

Attachment II: NOx Calculation Spreadsheets

Ameren SCR Calculations

SCR Urea	Rush Island Snapshot SCR

Inputs	Source	B1	B2	
Full Load Capacity (MW)	Capacity	621	621	
Net Plant Heat input rate (MMBtu/MW)	design rate/max load with 5% reduction	10.04	10.04	
Max heat input rate (Mmbtu/hr)	design rate	5922	5922	
Max annual MW Output	Calc: MW baseplate *8760	5,439,960	5,439,960	
Est annual MW Output	Estimate from past air markets data	3,780,000	3,780,000	
Est time control operates	Estimate from past air markets data	7,332	7,361	
Est time boiler operates	Estimate from past air markets data	7,332	7,361	
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.695	0.695	
Reagent	Urea	-	-	
Nox Inlet lb/mmbtu	From actuals achieved with LNB/OFA	0.08	0.08	
Nox Outlet lb/mmbtu	Goal number - COST manual says outlet SCR is rarely below 0.04 per their review of CAMD data	0.04	0.04	
Nox Removal Efficiency	Calc (Noxin-Noxout)/Nox in	50%	50%	
Nox Removed per Hour (lb/hr)	Calc (Noxin * Effic * Max annual heat input rate)	249.39	249.39	
Total Nox Removed per year (tons)	Calc: Nox per hr removed * Time SCR operates/2000	759.02	759.02	**Urea Total**
Capital Cost (to build it, 2016 dollars)	From Tool, all defaults	$ 187,617,577	$ 187,617,577	**$ 375,235,155**
Annual Cost (to operate it one year, 2016 dollars)	From Tool, all defaults, includes divided capital cost over years of operation	$ 23,213,468	$ 23,213,468	**$ 46,426,936**
Cost Effectiveness ($/ton, 2016 dollars)	Calc: Annual Cost by tons reduced	$ 30,583.31	$ 30,583.31	**$ 30,583**
Capital Cost (to build it, 2020 dollars)	Increase by 2% per year from 2016, 4 years total, 8%	$ 202,626,984	$ 202,626,984	**$ 405,253,967**
Annual O&M (one year operation, w/o capital recovery, 2020 dollars)	Increase by 2% per year from 2016, 4 years total, 8%	$ 2,827,832	$ 2,827,832	**$ 5,655,664**
Annualized Cost (operate and capital recovery, 2020 dollars)	Increase by 2% per year from 2016, 4 years total, 8%	$ 25,070,545	$ 25,070,545	**$ 50,141,091**
Cost Effectiveness ($/ton, 2020 dollars)	Increase by 2% per year from 2016, 4 years total, 8%	$ 33,030	$ 33,030	**$ 33,030**

Rush Island SCR B1 & B2 All Inputs		Source
Retrofit Factor	1.2	increase from default of 1.0
MW Rating at full load capacity	621	Plant specific
HHV of fuel	8826	default
Estimated acutal MWhs output	3,780,000	Plant specific
Net Plant Heat input rate (mmbtu/MW)	10.04	Plant specific
Sulfur content of fuel	0.19	Plant specific
Number of days SCR operates	305	Plant specific
Number of days boiler operates	305	Plant specific
Inlet Nox	0.08	Plant specific
Outlet Nox	0.04	Choice
Stoichiometric Ratio Factor	0.525	default 0.525 Urea, 1.05 ammonia
Number of Chambers	1	
Number of catalyst layers	2	
Number of empty layers	1	
Ammonia slip (ppm)	2	default
Volume of Layers	unk	
Flue Gas flow rate	unk	
Gas Temp at Inlet	750	
Base case fuel gas volumetric flow rate	516	default
Estimated operating life of catalyst	24,000	default
Estimated SCR equipment life (yrs)	13	default= 30, est startup 2023+3 years, retire 2039
Concentration of stored reagent	50	default 50 Urea, 29 ammonia
Density of reagent	71	default 71 Urea, 56 ammonia
Number of days reagent stored	14	default
Reagent	Urea	Choice
Desired dollar year	2016	default
CEPCI for goal year	541.7	default
CEPCI for 2016	541.7	default
Annual Interest Rate	5.5	default
Reagent cost	$ 1.66	default 1.66 urea, 0.293 ammonia
Electric cost	0.0361	default
Catalyst cost	$ 227	default
Operator Labor rate	$ 60	default
Operator hours/day	4	default
Maintenance Cost Factor	0.005	default
Administrative cost factor	0.03	default

Ameren SNCR Calculations

Per the Control Cost Manual, the equations should not be used for outlet emissions below 0.1 lb/mmbtu, and Ameren units are already emitting below this rate.

Rush Island SNCR Estimate

To get a general estimate of cost/ton, using potential emission reductions and general total costs to create an estimate.

Emission reductions possible at Labadie:

Current emissions rate:	
0.08	lb/mmbtu
2,911.4	tons per year (avg 2016-2019)
3,000	rounded tons per year
At 20% reduction	600 tons reduced
At 15% reduction	450 tons reduced

Sum of NOx (tons)		2016	2017	2018	2019	Grand Total
Labadie		6,576	7,050	7,138	6,883	27,647
	1	1,758	1,883	1,992	1,536	7,169
	2	1,803	1,928	2,016	1,474	7,221
	3	1,650	1,485	1,298	2,068	6,501
	4	1,365	1,753	1,832	1,805	6,756
Rush Island		2,664	3,584	3,210	2,188	11,646
	1	1,631	1,754	1,380	1,010	5,774
	2	1,033	1,830	1,830	1,178	5,871

Estimated Control Efficiency	20% reduction	15% reduction
Tons Reduced	600	450
Cost Effectiveness Goal	Annualized Cost Threshold	
$5,000/ton	$ 3,000,000	$ 2,250,000
$8,000/ton	$ 4,800,000	$ 3,600,000
$10,000/ton	$ 6,000,000	$ 4,500,000

Typical breakdown of annual costs for utility boilers is 25% capital recovery, 75% operating expense (page 1-7)

Estimated Control Efficiency	20% reduction	15% reduction
Tons Reduced	600	450

NESCAUM study on BART from 2005 says capital cost of SNCR is $10 to $20/kw - use midpoint $15/kw

621 MW =>	621,000.00 kw	$ 9,315,000		2 units
each unit B1 and B2		in 2005 dollars		
		$ 12,109,500		$ 24,219,000
		in 2020 dollars		
			Plant Total SNCR Capital Installation Cost	$ 24,219,000
			in 2020 dollars	

Avg annual cost per year

U1 &2 Lifetime		Capital Cost Divided by Operation Years
13	years (units 1 and 2 combined)	$ 1,863,000
Per unit		$ 931,500.00

Plant Annual Capital Cost (25%) in 2020 dollars	$ 1,863,000
Plant Annual Operating Expense (75%) in 2020 dollars	$ 5,589,000
Plant Annualized Cost (total above) in 2020 dollars	$ 7,452,000
Tons reduced per year (@ 15% red)	450
Cost Effectiveness ($/ton) in 2020 dollars	$ 16,560

Ameren – Rush Island Control Technology Costs Based on 3.25% Interest Rate

Units 1 and 2
Sulfur Dioxide (SO_2)
Wet FGD

Inputs	Source	B1	B2	
Full Load Capacity (MW)	nameplate	621	621	
Net Plant Heat input rate (MMBtu/MW)	design rate/max load with 5% reduction	10.04	10.04	
Max heat input rate (Mmbtu/hr)	design rate	5922	5922	
Max annual MW Output	Calc: MW nameplate *8760	5,439,960	5,439,960	
Est annual MW Output	Estimated from averaged past air markets data	3780000	3780000	
Est time control operates	Estimate from past air markets data	7,332	7,361	
Est time boiler operates	Estimate from past air markets data	7,332	7,361	
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.695	0.695	
SO2 baseline lb/mmbtu	Estimated from averaged past air markets data	0.51	0.51	
SO2 Outlet lb/mmbtu	Estimated after control added	0.05	0.05	
SO2 Removal Efficiency	Calc (SO2in-SO2out)/SO2 in	90%	90%	
SO2 Removed per Hour (lb/hr)	Calc (SO2in * Effic * Max annual heat input rate)	2724	2724	
Total SO2 Removed per year (tons)	Calc: SO2 per hr removed * Time control operates/2000	8291	8291	
Retrofit Factor		1.50	1.50	
Remaining Equipment Life	Based on Construction Time and Remaining Life of Unit	11	11	
Number of Additional Personnel	Default from Manual	16	16	
Hourly Labor Rate	Default from Manual	60	60	
Limestone Cost ($/ton)	Updated based on Ameren specific data	60	60	
Make-up water cost ($/gallon)	Updated based on Ameren specific data	0.0063	0.0063	
Waste Disposal ($/ton)	Default from Manual	30	30	
Electricity Cost ($/kwh)	Default from Manual	0.0361	0.0361	
Assumed Interest Rate	Default from Manual (NOx and SO2 sections were different. Using NOx value since SO2 section is still in draft)	5.5%	5.5%	
	Capital Cost (2016 $)	$ 398,409,309	$ 398,409,309	
	Direct Annual Cost (2016 $)	$ 11,980,040	$ 11,980,040	
	Annualized Cost (2016 $)	$ 55,745,189	$ 55,745,189	**Total**
	Captial Cost (2020 $)	$ 430,282,054	$ 430,282,054	**$ 860,564,108**
	Direct Annual Cost (2020 $)	$ 12,938,443	$ 12,938,443	**$ 25,876,887**
	Annualized Cost (2020 $)	$ 60,204,805	$ 60,204,805	**$ 120,409,609**
	Cost Effectiveness (2020 $/ton)	$ 7,262	$ 7,262	

Ameren Study Cost Estimations	B1	B2	**Total**
Captial Cost (2020 $)	$ 422,280,000	$ 422,280,000	**$ 844,560,000**
Direct Annual Cost (2020 $)	$ 7,560,000	$ 7,560,000	**$ 15,120,000**
Annualized Cost (2020 $)	$ 53,833,171.13	$ 53,833,171.13	**$ 107,666,342**
Cost Effectiveness (2020 $/ton)	$ 6,493	$ 6,493	

SDA

Inputs	Source	B1	B2	
Full Load Capacity (MW)	nameplate	621	621	
Net Plant Heat input rate (MMBtu/MW)	design rate/max load with 5% reduction	10.04	10.04	
Max heat input rate (Mmbtu/hr)	design rate	5922	5922	
Max annual MW Output	Calc: MW nameplate *8760	5,439,960	5,439,960	
Est annual MW Output	Estimated from averaged past air markets data	3780000	3780000	
Est time control operates	Estimate from past air markets data	7,332	7,361	
Est time boiler operates	Estimate from past air markets data	7,332	7,361	
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.695	0.695	
SO2 baseline lb/mmbtu	Estimated from averaged past air markets data	0.51	0.51	
SO2 Outlet lb/mmbtu	Estimated after control added	0.06	0.06	
SO2 Removal Efficiency	Calc (SO2in-SO2out)/SO2 in	88%	88%	
SO2 Removed per Hour (lb/hr)	Calc (SO2in * Effic * Max annual heat input rate)	2665	2665	
Total SO2 Removed per year (tons)	Calc: SO2 per hr removed * Time control operates/2000	8111	8111	
Retrofit Factor		1.50	1.50	
Remaining Equipment Life	Based on Construction Time and Remaining Life of Unit	11	11	
Number of Additional Personnel	Default from Manual	8	8	
Hourly Labor Rate	Default from Manual	60	60	
Lime Cost ($/ton)	Default from Manual	125	125	
Make-up water cost ($/gallon)	Updated based on Ameren specific data	0.0063	0.0063	
Waste Disposal ($/ton)	Default from Manual	30	30	
Electricity Cost ($/kwh)	Default from Manual	0.0361	0.0361	
Assumed Interest Rate	Default from Manual (NOx and SO2 sections were different. Using NOx value since SO2 section is still in draft)	3.3%	3.3%	
	Capital Cost (2016 $)	$ 348,753,600	$ 348,753,600	
	Direct Annual Cost (2016 $)	$ 10,150,764	$ 10,150,764	
	Annualized Cost (2016 $)	$ 48,438,762	$ 48,438,762	**Total**
	Captial Cost (2020 $)	$ 376,653,888	$ 376,653,888	**$ 753,307,776**
	Direct Annual Cost (2020 $)	$ 10,962,825	$ 10,962,825	**$ 21,925,650**
	Annualized Cost (2020 $)	$ 52,313,863	$ 52,313,863	**$ 104,627,726**
	Cost Effectiveness (2020 $/ton)	$ 6,450	$ 6,450	

DSI*

	Without Fabric Filter			
Rush Island		assumed 50% removal efficiency		
Inputs	**Source**	**B1**	**B2**	
Full Load Capacity (MW)	nameplate	621	621	
Max heat input rate (Mmbtu/hr)	design rate	5922	5922	
Max annual MW Output	Calc: MW nameplate *8760	5,439,960	5,439,960	
Est annual MW Output	Estimated from averaged past air markets data	3780000	3780000	
Est time control operates	Estimate from past air markets data	7,332	7,361	
Est time boiler operates	Estimate from past air markets data	7,332	7,361	
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.695	0.695	
SO2 baseline lb/mmbtu	Estimated from averaged past air markets data	0.51	0.51	
SO2 Outlet lb/mmbtu	Estimated after control added	0.26	0.26	
SO2 Removal Efficiency		50%	50%	
Assumed Interest Rate	Default from Manual (using NOx section interest rate)	3.25%	3.25%	
Remaining Equipment Life	Based on Construction Time and Remaining Life of Unit	13	13	
Capital Recovery Factor		0.0955	0.0955	
SO2 Removed per Hour (lb/hr)	Calc (SO2in * Effic * Max annual heat input rate)	1510	1510	
Total SO2 Removed per year (tons)	Calc: SO2 per hr removed * Time control operates/2000	4596	4596	**Total**
	Captial Cost (2020 $)	$ 71,338,000	$ 71,338,000	**$ 142,676,000**
	Direct Annual Cost (2020 $)	15,688,000	15,688,000	**$ 31,376,000**
	Annualized Cost (2020 $)	$ 22,503,579	$ 22,503,579	**$ 45,007,158**
	Cost Effectiveness (2020 $/ton)	$ 4,896	$ 4,896	

	With Fabric Filter			
Rush Island		assumed 70% removal efficiency		
Inputs	**Source**	**B1**	**B2**	
Full Load Capacity (MW)	nameplate	621	621	
Max heat input rate (Mmbtu/hr)	design rate	5922	5922	
Max annual MW Output	Calc: MW nameplate *8760	5,439,960	5,439,960	
Est annual MW Output	Estimated from averaged past air markets data	3780000	3780000	
Est time control operates	Estimate from past air markets data	7,332	7,361	
Est time boiler operates	Estimate from past air markets data	7,332	7,361	
Total System Capacity Factor	Calc (Est output/Max output) * (Time controlled/Time boiler ops)	0.695	0.695	
SO2 baseline lb/mmbtu	Estimated from averaged past air markets data	0.51	0.51	
SO2 Outlet lb/mmbtu	Estimated after control added	0.16	0.16	
SO2 Removal Efficiency		70%	70%	
Assumed Interest Rate	Default from Manual (using NOx section interest rate)	3.25%	3.25%	
Remaining Equipment Life	Based on Construction Time and Remaining Life of Unit	13	13	
Capital Recovery Factor		0.0955	0.0955	
SO2 Removed per Hour (lb/hr)	Calc (SO2in * Effic * Max annual heat input rate)	2102	2102	
Total SO2 Removed per year (tons)	Calc: SO2 per hr removed * Time control operates/2000	6398	6398	**Total**
	Captial Cost (2020 $)	$ 139,358,000	$ 139,358,000	**$ 278,716,000**
	Direct Annual Cost (2020 $)	21,963,200	21,963,200	**$ 43,926,400**
	Annualized Cost (2020 $)	$ 35,277,359	$ 35,277,359	**$ 70,554,718**
	Cost Effectiveness (2020 $/ton)	$ 5,514	$ 5,514	

Units 1 and 2
Nitrogen Oxides (NO_x)
SCR – Ammonia

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}) =	$131,963,063	in 2016 dollars
Reagent Preparation Cost (RPC) =	$2,689,563	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2016 dollars
Balance of Plant Costs (BPC) =	$9,668,588	in 2016 dollars
Total Capital Investment (TCI) =	$187,617,577	in 2016 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.

$202,626,983.67

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}) =	$131,963,063 in 2016 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) =	$2,689,563 in 2016 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 2016 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}) =	$9,668,588 in 2016 dollars

Annual Costs

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

Direct Annual Costs (DAC) =	$2,345,938 in 2016 dollars
Indirect Annual Costs (IDAC) =	$17,930,932 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	$20,276,870 in 2016 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 =	$938,088 in 2016 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	$79,625 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	$781,707 in 2016 dollars
Annual Catalyst Replacement Cost =		$546,518 in 2016 dollars
For coal-fired boilers, the following methods may be used to calcuate the catalyst replacement cost.		
Method 1 (for all fuel types):	n_{scr} x Vol_{cat} x ($CC_{replace}$/R_{layer}) x FWF	* Calculation Method 1 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 =		$2,345,938 in 2016 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) =	$13,453 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	$17,917,479 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	$17,930,932 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	$20,276,870 per year in 2016 dollars
NOx Removed =	759 tons/year
Cost Effectiveness =	$26,714 per ton of NOx removed in 2016 dollars

$21,899,019.12
$28,851.55

SCR – Urea

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}) =	$131,963,063	in 2016 dollars
Reagent Preparation Cost (RPC) =	$2,689,563	in 2016 dollars
Air Pre-Heater Costs (APHC)* =	$0	in 2016 dollars
Balance of Plant Costs (BPC) =	$9,668,588	in 2016 dollars
Total Capital Investment (TCI) =	$187,617,577	in 2016 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.

$202,626,983.67

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}) =	$131,963,063 in 2016 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) =	$2,689,563 in 2016 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 2016 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}) =	$9,668,588 in 2016 dollars

Annual Costs

Total Annual Cost (TAC)

TAC = Direct Annual Costs + Indirect Annual Costs

Direct Annual Costs (DAC) =	\$2,630,218 in 2016 dollars
Indirect Annual Costs (IDAC) =	\$17,930,932 in 2016 dollars
Total annual costs (TAC) = DAC + IDAC	\$20,561,150 in 2016 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 =	\$938,088 in 2016 dollars
Annual Reagent Cost =	m_{sol} x $Cost_{reag}$ x t_{op} =	\$363,905 in 2016 dollars
Annual Electricity Cost =	P x $Cost_{elect}$ x t_{op} =	\$781,707 in 2016 dollars
Annual Catalyst Replacement Cost =		\$546,518 in 2016 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 1 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 =		\$2,630,218 in 2016 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) =	\$13,453 in 2016 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$17,917,479 in 2016 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$17,930,932 in 2016 dollars

Cost Effectiveness

Cost Effectiveness = Total Annual Cost/ NOx Removed/year

Total Annual Cost (TAC) =	\$20,561,150 per year in 2016 dollars
NOx Removed =	759 tons/year
Cost Effectiveness =	\$27,089 per ton of NOx removed in 2016 dollars
	\$22,206,041.74
	\$29,256.05

Units 1 and 2
Nitrogen Oxides (NO_x)
SNCR

Per the Control Cost Manual, the equations should not be used for outlet emissions below 0.1 lb/mmbtu, and Ameren units are already emitting below this rate.													
Labadie SNCR Estimate													
To get a general estimate of cost/ton, using potential emission reductions and general total costs to create an estimate.													
Emission reductions possible at Labadie:													
Current emissions rate:								Sum of NOx (tons)					
	0.08	lb/mmbtu							2016	2017	2018	2019	Average
	2,911.50	tons per year (avg 2016-2019)						Labadie	6,576	7,049	7,138	6,883	6,912
	3,000	rounded tons per year						B1	1,758	1,883	1,992	1,536	
At 20% reduction	600	tons reduced						B2	1,803	1,928	2,016	1,474	
At 15% reduction	450	tons reduced						B3	1,650	1,485	1,298	2,068	
								B4	1,365	1,753	1,832	1,805	
								Rish Island	2,664	3,584	3,210	2,188	2,912
								B1	1,631	1,754	1,380	1,010	
								B2	1,033	1,830	1,830	1,178	
Estimated Control													
Efficiency	15%	20%	eduction										
Tons Reduced	450	600											
Cost Effectiveness													
Goal	Annualized Cost Threshold												
$5,000/ton	$ 2,250,000	$ 3,000,000											
$8,000/ton	$ 3,600,000	$ 4,800,000											
$10,000/ton	$ 4,500,000	$ 6,000,000											
Typical breakdown of annual costs for utility boilers is 25% capital recovery, 75% operating expense (page 1-7)													
NESCAUM study on BART from 2005 says capital cost of SNCR is $10 to $20/kw - use midpoint $15/kw													
	Base Load (MW)	Base Load (KW)	Capital Cost 2005 $	Capital Cost 2020 $	Life Time	Annual Cost 2020 $	Annual Operating Expense (75%)	Total Cost	Cost Effectiveness ($/ton)				
B1	621	621,000	9,315,000	12,109,500	13	931,500	2,794,500	3,726,000					
B2	621	621,000	9,315,000	12,109,500	13	931,500	2,794,500	3,726,000					
	Plant Total SNCR Capital Installation Cost			24,219,000.00	Plant	1,863,000	5,589,000	7,452,000	16,560				

Summary of the Air Program Evaluation

In conclusion, based on a review of possible and feasible options to reduce SO2 and NOx emissions at Unit 1, the Air Program has determined that there are no cost-effective methods of SO2 and NOx reduction for this facility. All Class I areas impacted by sources in Missouri have made steady and significant improvement in visibility, and modeling shows they are projected to be below, or well below, their uniform rate of progress (URP) glidepaths in 2028. Based on the four factor analysis completed in this report, the Air Program is proposing to maintain current operational practices consistent with the parameters and limits in Rush Island Air Pollution Control Title V Permit to Operate.

**All control cost estimate calculations for wet FGD, SDA, DSI, SCR, and SNCR for both remaining useful life (RUL) scenarios are provided in the attached 18 spreadsheets.

Example of the spreadsheets

Rush Island 1 SCR urea NPS-EPA-RUL.xlsm
Rush Island 1 SCR urea NPS-Original-RUL.xlsm

All spreadsheets are in Missouri Regional Haze Plan for the Second Planning Period, Attachment C