Appendix G

Reasonable Progress Evaluation/Long Term Strategy

Appendix G-1

Lhoist 4 Factor Analysis

Appendix G-1a

Lhoist Montevallo Letter from Alabama Requesting Four Factor Analysis - October 29, 2020

LANCE R. LEFLEUR
DIRECTOR

ADEM

KAY IVEY
GOVERNOR

Alabama Department of Environmental Management
adem.alabama.gov

1400 Coliseum Blvd. 36110-2400 ■ Post Office Box 301463
Montgomery, Alabama 36130-1463
(334) 271-7700 ■ FAX (334) 271-7950

October 29, 2020

Mr. Craig Gordinier
Plant Manager
Lhoist North America of Alabama, LLC
Montevallo Plant
7444 Highway 25 South
Calera, AL 35040

RE: Regional Haze Rule – Four-Factor Analysis Request
Lhoist – Montevallo Plant
Facility No. 411-0008

Dear Mr. Gordinier:

The 2017 Regional Haze Rule, 40 CFR Parts 51 and 52, mandated by the Clean Air Act (CAA) sections 169A and 169B, requires that programs be implemented for the protection of visibility in mandatory Federal Class I areas. In the state of Alabama, the Sipsey Wilderness Area is identified by the rule. ADEM has been working with the southeast regional partnership, VISTAS, to perform a regional scale Area of Influence (AOI) modeling analysis to identify sources based on emissions that would significantly contribute to decreased visibility in Class I areas throughout the southeast. Alabama chose to further analyze sources whose 2028 emissions contributed greater than 2% of the total emissions impacting the Sipsey Wilderness with the CAMx photochemical model, using the source apportionment option (PSAT), to determine which sources, if any, should be evaluated for a four-factor analysis. Due to the use of updated sulfur dioxide (SO_2) emissions factors for rotary lime kilns, it was determined that the 2028 emissions for the Lhoist Montevallo plant (Lhoist) were significantly higher than was previously modeled. Through ratioing the new corrected emissions with the previous results, it was found that Lhoist's impact would have been approximately 2.69%. Based on these results, any source's emissions that caused an impact of 1.0% or greater on visibility was considered for a four-factor analysis. Therefore, ADEM is requiring that a four-factor analysis be completed for the SO_2 sources at this facility.

General guidelines for the analysis can be found in 40 CFR §51.308. The purpose of the analysis is to assess the viability of emissions control technology options to achieve the State's reasonable progress goals for natural visibility conditions. The analysis should address the following factors for SO_2 sources at the facility:

1) The cost of implementation of SO_2 emissions controls (in dollars per ton [$/ton] of SO_2 reduced)

Birmingham Branch
110 Vulcan Road
Birmingham, AL 35209-4702
(205) 942-6168
(205) 941-1603 (FAX)

Decatur Branch
2715 Sandlin Road, S.W.
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(256) 353-1713
(256) 340-9359 (FAX)

Mobile Branch
2204 Perimeter Road
Mobile, AL 36615-1131
(251) 450-3400
(251) 479-2593 (FAX)

Mobile-Coastal
3664 Dauphin Street, Suite B
Mobile, AL 36608
(251) 304-1176
(251) 304-1189 (FAX)

2) The time necessary for implementation of controls

3) The energy and non-air quality compliance impacts of controls

4) The remaining useful life of existing sources that contribute to visibility impairment

Please submit the requested information to ADEM Air Division by February 1, 2021. If you have any questions concerning this matter, please contact Skyler Sanderson at (334) 270-5647 or Tim Martin at (334) 270-5672 in Montgomery.

Sincerely,

Ronald W. Gore, Chief
Air Division

RWG/MSS

Appendix G-1b

Lhoist Montevallo Letter from Alabama Requesting Additional Information #1 - March 2, 2021

ADEM

Alabama Department of Environmental Management
adem.alabama.gov

1400 Coliseum Blvd. 36110-2400 ▪ Post Office Box 301463
Montgomery, Alabama 36130-1463
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March 2, 2021

Mr. Craig Gordinier
Plant Manager
Lhoist North America of Alabama, LLC
Montevallo Plant
7444 Highway 25 South
Calera, AL 35040

RE: **Regional Haze Rule – Four-Factor Analysis Additional Information Request**
Lhoist – Montevallo Plant
Facility No. 411-0008

Dear Mr. Gordinier:

On October 29, 2020, ADEM submitted a request to Lhoist North America of Alabama, LLC
(LNA) for a four-factor analysis for the Montevallo Plant as part of the 2017 Regional Haze Rule
(40 CFR Parts 51 and 52). The purpose of the analysis is to assess the viability of emissions control
technology options to achieve the State's reasonable progress goals for natural visibility conditions
in the Sipsey Wilderness Area. The analysis is required to address the following factors for SO_2
sources at the facility:

1) The cost of implementation of SO_2 emissions controls (in dollars per ton [\$/ton] of SO_2
   reduced)

2) The time necessary for implementation of controls

3) The energy and non-air quality compliance impacts of controls

4) The remaining useful life of existing sources that contribute to visibility impairment

LNA submitted an analysis on February 5, 2021, that addresses the four factors listed above. As
part of the analysis, LNA assesses the viability of various alternative fuel scenarios for the four
existing rotary lime kilns. The kilns currently fire a combination of standard coal, petroleum coke,
and natural gas. The exact ratio of these fuels is based on operating conditions and product
specifications. The alternative fuel scenarios assessed in the analysis are maximum standard coal,
increased standard coal, maximum low-sulfur coal, and increased natural gas. The technical and
economic feasibility of each scenario is assessed and quantified in dollars per ton of SO_2 reduced
(\$/ton).

Birmingham Branch
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Decatur Branch
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(256) 353-1713
(256) 340-9359 (FAX)

Mobile Branch
2204 Perimeter Road
Mobile, AL 36615-1131
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Mobile-Coastal
3664 Dauphin Street, Suite B
Mobile, AL 36608
(251) 304-1176
(251) 304-1189 (FAX)

ADEM requests a similar analysis for the following scenarios:

- An analysis, similar to the one performed for increased coal operations, which utilizes low sulfur coal. Please include the ratio of petroleum coke, natural gas, and low sulfur coal usage.

- An analysis of current fuel firing operations substituting low sulfur coal for the current coal quality. Please include the ratio of petroleum coke, natural gas, and low sulfur coal usage.

- Higher rates of natural gas usage, in addition to the twenty percent scenario provided (LNA states that a natural gas rate higher than twenty percent of total fuel would require "significant capital investment" and "extensive timing" due to the increased infrastructure demands, but no analysis of these costs is provided.)

In addition to this information request, ADEM would like to note we are considering requiring continuous emissions monitoring for SO_2 on the four existing kilns due to the uncertainty in emission calculation methods used in the past decade. ADEM will consider this possibility concurrently with the regional haze assessment.

ADEM would also like to point out the following list of top SO_2 sources in Alabama projected for 2021:

Rank	Facility Name	2021 Expected SO_2 Emissions (TPY)
1	Lhoist North America of Alabama, LLC – Montevallo Plant	9,377
2	Coal Fired Utility #1	3,494
3	Natural Gas Processor	2,628
4	Carbon Black Plant	2,574
5	Lhoist North America of Alabama, LLC – Alabaster Plant	1,698
6	Chemical Plant #1	1,634
7	Lead Smelter	1,380
8	Paper Mill	1,182
9	Coal Fired Utility #2	1,150
10	Chemical Plant #2	1,020

Please submit the requested information to ADEM Air Division by March 26, 2021. If you have any questions concerning this matter, please contact Skyler Sanderson at (334) 270-5647 in Montgomery.

Sincerely,

Ronald W. Gore, Chief
Air Division

RWG/MSS

Appendix G-1c

Lhoist Montevallo Letter from Alabama Requesting Additional Information #2 - April 14, 2021

ADEM

Alabama Department of Environmental Management
adem.alabama.gov

1400 Coliseum Blvd. 36110-2400 ■ Post Office Box 301463
Montgomery, Alabama 36130-1463
(334) 271-7700 ■ FAX (334) 271-7950

April 14, 2021

Mr. Craig Gordinier
Plant Manager
Lhoist North America of Alabama, LLC
Montevallo Plant
7444 Highway 25 South
Calera, AL 35040

RE: **Regional Haze Rule – Four-Factor Analysis Additional Information Request**
Lhoist – Montevallo Plant
Facility No. 411-0008

Dear Mr. Gordinier:

In two recent iterations, Lhoist has provided information to ADEM known as a "four-factor analysis". This information is to enable ADEM to determine whether SO_2 reductions are feasible at your facility for the purpose of improving visibility at the Sipsey Wilderness Area. Thank you for those efforts.

ADEM is requesting further clarification as described below.

As conveyed to you in previous correspondence, Lhoist emits by far the highest amount of SO_2 per year of any facility in ADEM's jurisdiction. That level of emissions, plus the proximity to the Sipsey, means that L-M is the only facility in the State which ADEM has determined to have a significant negative impact on visibility in this protected area.

The most recent response from Lhoist included analyses of alternative fuel scenarios using increasing increments of natural gas for each kiln. The response also included a letter from Spire Inc. stating the facility currently has a connective load capacity of 330 MMBtu of natural gas per hour (MMBtu/hr) and is working on a potential solution to provide additional capacity (i.e. to 1,000 MMBtu/hr to operate all kilns on 100% natural gas) in the future.

ADEM requests additional information for the following fuel scenarios at the Montevallo Plant:

- Higher rates of natural gas usage for Kilns 3 and 4, which have no SO_2 controls, using the existing natural gas capacity rather than an even distribution of 20% per kiln (i.e. maintain current natural gas percentage for Kilns 1 and 2 while using the remaining natural gas capacity on Kilns 3 and 4)

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110 Vulcan Road
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(205) 942-6168
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Decatur Branch
2715 Sandlin Road, S.W.
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Mobile-Coastal
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- 100% natural gas for all four kilns including any financial share of the additional capacity solution by Spire Inc. that would be incurred by or passed on to Lhoist. This should address, at minimum, the following factors:

    1. The time Spire Inc. determines it would take to increase capacity to the facility or provide a realistic plan for doing so.

    2. The decreased cost from not having to handle and store solid fuels.

    3. The cost savings from decreased kiln downtime for cleaning and maintenance due to not burning solid fuels.

Please submit the requested information to ADEM Air Division by May 18, 2021. If you have any questions concerning this matter, please contact Skyler Sanderson at (334) 270-5647 in Montgomery.

Sincerely,

Ronald W. Gore, Chief
Air Division

RWG/MSS

Appendix G-1d

Lhoist Montevallo Four Factor Analysis - February 2021

Lhoist

LHOIST NORTH AMERICA OF ALABAMA, LLC

Montevallo Plant

**Regional Haze Second Planning Period
four-Factor Analysis**

February 2021

Trinity
Consultants

February 5, 2021

Mr. Ron Gore
Environmental Engineering Specialist, Senior
Air Division, Energy Branch
Alabama Department of Environmental Management
1400 Coliseum Boulevard
Montgomery, AL 36110-2400

RE: **Lhoist North America of Alabama, LLC - Montevallo Plant**
 Facility No. 411-0008
 Regional Haze Rule – Four Factor Analysis Request

Dear Mr. Gore:

As requested in the ADEM letter dated October 29, 2020, please find attached the requested Four-Factor analysis for the Montevallo facility regarding SO_2 emissions.

If you have any questions or comments about the information presented in the attached Four-Factor Analysis, please feel free to contact Michael Will, the Senior Environmental Engineer for Alabama Operations, at (205) 444-4905 or via email.

Sincerely,

Lhoist North America of Alabama, LLC

Craig Gordinier
Montevallo Plant Manager

Attachment – Four-Factor Analysis

cc: Mr. Tim Martin (ADEM)
 Ms. Jennifer Youngpeter (ADEM)
 Mr. Skyler Sanderson (ADEM)
 Mr. Chris Scholl (LNA)
 Mr. Michael Will (LNA)

REGIONAL HAZE SECOND PLANNING PERIOD FOUR-FACTOR ANALYSIS

⸜⸜Lhoist

Lhoist North America of Alabama, LLC / Montevallo Plant

Prepared By:

TRINITY CONSULTANTS
3495 Piedmont Road NE
Building 10, Suite 905
Atlanta, GA 30305
678-441-9977

February 2021

Project 201101.0234

Trinity ◢◣
Consultants

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1. EXECUTIVE SUMMARY

This report documents the results of a four-factor control analysis of the four lime kilns at the Lhoist North America of Alabama, LLC (Lhoist) Montevallo Plant (the Facility). All kilns are rotary type kilns that can produce between 375 and 750 tons per day (tpd) of lime, each. This report is provided in response to the Alabama Department of Environmental Management (ADEM) request letter dated October 29, 2020, requesting a four-factor analysis based on revised and updated screening level results for the Facility's visibility impairment due to sulfur dioxide (SO_2) emissions for the Sipsey Wilderness Area. Therefore, this report focuses on evaluation of SO_2 emissions from the primary SO_2 emissions sources at the Facility, Kilns 1-4.[1]

The Facility was evaluated during the first regional haze planning period (Kilns 1, 3, and 4) and it was determined that the Facility did not contribute to visibility impairment at nearby Class I areas and was not subject to Best Available Retrofit Technology (BART) requirements. Therefore, a four-factor analysis was not conducted for the facility at that time.

During the second planning period for Regional Haze, the U.S. EPA's guidelines in 40 CFR Part 51.308 are used to evaluate control options for the lime kilns. In establishing a reasonable progress goal for any mandatory Class I Federal area within the State, the State must consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these four factors are taken into consideration in selecting the goal.[2] The most recent guidance, released by U.S. EPA on August 20, 2019, additionally states in reference to SIP development that:

> ***Importantly, this section assumes that the state will consider visibility benefits as part of the analysis.*** *Section 51.308(f)(2)(i) of the Regional Haze Rule requires consideration of the four factors listed in CAA section 169A(g)(1) and does not mention visibility benefits. However, neither the CAA nor the Rule suggest that only the listed factors may be considered.* ***Because the goal of the regional haze program is to improve visibility, it is reasonable for a state to consider whether and by how much an emission control measure would help achieve that goal. [Emphasis Added]***

As such, all cost effectiveness figures presented in this document should be considered in the context of the original visibility modeling for the first planning period, which demonstrated that the Facility did not significantly contribute to visibility impairment at any Class I areas.

The purpose of this report is to provide information to ADEM regarding potential SO_2 emission reduction options for the Facility's four lime kilns with the knowledge that the Facility's visibility impairing impacts are minimal. Based on the Regional Haze Rule, associated U.S. EPA guidance, and ADEM's request, Lhoist presumes that ADEM will only move forward with requiring emission reductions from the Facility's lime kilns if the emission reductions can be demonstrated to contribute to reasonable progress and provide the most cost effective controls among all options available to ADEM. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

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[1] As part of the first implementation period under Regional Haze, Kiln 2 was not considered a BART eligible source. Kiln 2 was originally called Kiln 1, and was constructed before 1962.

[2] 40 CFR 51.308(d)(1)(i)(A)

The report identifies the following potential control technologies for the Facility's lime kilns:

PM$_{10}$ Emission Reduction Options

► The Facility's kilns are subject to the National Emissions Standards for Hazardous Air Pollutants listed in 40 CFR Part 63, Subpart AAAAA. The current baghouses and wet scrubbers used for control of particulate matter emissions from the Facility's kilns meet the applicable emission limits of Subpart AAAAA and therefore, the baghouses and wet scrubbers meet the definition of maximum achievable control technology (MACT) for Rotary Lime Kilns. Further emission reduction options for particulate matter (PM) less than 10 microns in aerodynamic diameter (PM$_{10}$) have not been evaluated as it is not a pollutant of concern regarding visibility impairments at the Class I area potentially affected by the Facility (Sipsey Wilderness Area).

NO$_X$ Emission Reduction Options

► Emission reduction options for nitrogen oxides (NO$_X$) have not been evaluated as it is not a pollutant of concern regarding visibility impairments at the Class I area (Sipsey Wilderness Area) potentially affected by the Facility. The primary pollutant of concern for this analysis is SO$_2$.[3]

SO$_2$ Emission Reduction Options

► Inherent Dry Scrubbing: The specific designs of Kilns 1-4 at the Facility are not conducive to any significant inherent SO$_2$ emissions control as claimed for other kiln types at lime kiln operational facilities. The operation of the kilns is designed to minimize adsorption of SO$_2$ by the lime product to maintain high product quality. Therefore, due to the small amount of inherent emissions control for SO$_2$ that exists, this is not deemed to be an effective control method for the Facility.

► Alternative Fuel Scenarios: Alternative fuels are considered as a possibility for reducing SO$_2$ emissions and are evaluated on a kiln-by-kiln basis. Currently the kilns each fire a unique ratio of coal, coke, and natural gas based on operating conditions and the product being produced.

The control scenarios considered in this analysis are switching to maximum or increased coal, increased natural gas, or maximum low sulfur coal. All of these methods could potentially reduce SO$_2$ emissions but are deemed infeasible due to various reasons. Maximum coal, increased coal, and maximum low sulfur coal have secondary concerns (e.g., kiln operational issues, product quality, fuel supply uncertainty, increase in PM$_{10}$, NO$_X$, and metal HAPs emissions, etc.) preventing them from being feasible options. Natural gas is available at this location; however, natural gas supply for the facility is currently limited. An increase in natural gas usage up to 20% of heat input on Kilns 3 and 4 is feasible with the currently available gas supply. However, increasing natural gas to above 20% on Kilns 3 and 4 would impact production capability, quality, and significant capital investment would be required to accommodate this change as there is not sufficient supply available for the facility to run the kilns on significantly increased natural gas. The timing necessary to provide guaranteed natural gas supply for the facility for the existing kilns to run them fully on natural gas is unknown, but it is expected to be extensive.[4]

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[3] As identified in the ADEM request letter for submittal of the Four-Factor Analysis, dated October 29, 2020.

[4] Existing natural gas pipeline infrastructure for the Facility is not sufficient to run Kilns 1-4 fully on natural gas along with the recently permitted Kiln 5. Additional compression capability would be needed for the area.

Given the operational and availability limitations, the significant capital and/or operational expenses required, and associated negative impact on PM_{10}, NO_X, and/or metal HAPs emissions, it is not possible to suggest the replacement of any given fuel with another and claim with any certainty that the replacement provides any benefits towards reasonable progress. Such changes could also have a negative impact on facility production and product quality. The only fuel change that is deemed potentially feasible is increased natural gas usage to 20% on Kilns 3 and 4.

▶ Dry Sorbent Injection: Dry sorbent injection (DSI) operates under a two-step process where first a sorbent (e.g., hydrated lime) is injected directly into the flue gas where it adsorbs SO_2 to create a dry waste product. In the second step, the calcium/sulfur waste product is removed using downstream particulate control.[5] This method was found to be economically infeasible along with significant secondary impacts, including increased solid waste generation.

▶ Wet Flue Gas Desulfurization Scrubbing: Wet flue gas desulfurization scrubbing for Kilns 1 and 2 is deemed to be economically infeasible along with significant operational challenges. Wet flue gas desulfurization scrubbing for Kilns 3 and 4 is deemed potentially economically feasible. However, due to the high costs and downtime associated with implementation of this emissions control method, secondary influences to waste generation at the site (solid waste/water), and lack of direct evidence of significant visibility improvement at the Sipsey Wilderness Area due to these emissions reductions, and no need for any emissions reductions from these sources to meet reasonable progress for the Sipsey Wilderness Area at this time, Lhoist does not consider addition of wet flue gas desulfurization scrubbing on Kilns 3 and 4 feasible for visibility improvements at the Sipsey Wilderness Area as part of this implementation period.

▶ Semi-Wet/Dry Flue Gas Desulfurization Scrubbing: This control method was deemed to be redundant since semi-wet/dry flue gas desulfurization scrubbing operates under similar principles as wet flue gas desulfurization scrubbing, however, it is less effective and more costly. As a result, there would be no situation where semi-wet/dry flue gas desulfurization scrubbing would be preferred over wet flue gas desulfurization scrubbing at the Facility. Therefore, it was not fully considered as part of this assessment.

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[5] EPA Air Pollution Control Technology Factsheet for Flue Gas Desulfurization (FGD).

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to natural conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to natural conditions in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6,000 acres), wilderness areas (over 5,000 acres), national memorial parks (over 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. In establishing a reasonable progress goal for a Class I area, the State must:[6]

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

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

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

The purpose of this report is to provide information to ADEM regarding potential SO_2 emission reduction options for the Facility's four lime kilns with the knowledge that the Facility's visibility impairing impacts are minimal. Based on the Regional Haze Rule, associated U.S. EPA guidance, and ADEM's request, Lhoist understands that ADEM will only move forward with requiring emission reductions from the Facility's lime kilns if the emission reductions can be demonstrated to contribute to reasonable progress and provide the most cost effective controls among all options available to ADEM. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

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[6] 40 CFR 51.308(d)(i).

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

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

Factors 1 and 3 of the four factors that are listed above are considered by conducting a step-wise review of emission reduction options in a top-down fashion similar to the top-down approach that is included in the EPA RHR guidelines[7] for conducting a review of BART for a unit.[8] These steps are as follows:

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

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

Additionally, as mentioned in Section 1, the visibility modeling that was conducted for the first planning period is taken into consideration as an additional factor as the analysis demonstrated the Facility did not significantly contribute to visibility impairment at any Class I areas. Also, additional items discussed in Section 5.5 of this report should be considered as additional factors for this analysis.

A review of the four factors for SO_2 can be found in Section 5 of this report. As stated previously, PM_{10} and NO_x have not been evaluated in depth as they are not pollutants of concern regarding visibility impacts at the Class I area (Sipsey Wilderness Area) potentially affected by the Facility. Section 4 of this report includes information on the Facility's kilns and baseline emissions.

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[7] The BART provisions were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308 on July 5, 2005.

[8] References to BART and BART requirements in this Analysis should not be construed as an indication that BART is applicable to the Facility.

3. SOURCE DESCRIPTION

The Facility contains a limestone processing plant with a nominal capacity of 2,300 tons per day of product lime. Crushed limestone ore is trucked to the Facility from the nearby O'Neal and Brierfield Quarries. Sized stone is stockpiled by type and then reclaimed from stockpiles by underground belt conveyors and delivered by aboveground conveyors to one of four computer controlled, petroleum coke and coal-fired rotary lime kilns where it is calcined into quicklime. In the calcining process limestone is heated to the dissociation temperature where carbon dioxide (CO_2) is released, and the remaining calcium oxide (CaO) and magnesium oxide (MgO) is the quicklime product. Although the physical size of the pebble does not change appreciably when calcined, the pebble density is decreased because carbon dioxide comprises approximately half of the mass of the limestone.

Table 3-1 provides the installation dates and the nominal rated lime production capacity for each kiln.

Table 3-1. Kiln Production Capacity

Unit	Installation Date	Nominal Daily Production (Tons)	Annual Estimated Production (Tons)
Kiln 1	1968	425	155,000
Kiln 2	1955	375	137,000
Kiln 3	1973	750	274,000
Kiln 4	1977	750	274,000

This Section summarizes emission rates that are used as baseline rates in the four-factor analysis presented in Section 5 of this report.

Baseline annual emissions for SO_2 are calculated based on a mass balance approach utilizing future estimated annual production values. Using the production estimates and taking into account kiln efficiencies, fuel sulfur content, fuel heat content, limited inherent SO_2 control, and current add-on controls, Lhoist has calculated the baseline emission rates that will be used to evaluate different operating scenarios and controls. These baseline emission rates are expected to be representative of actual emissions projected for the year 2028. The baseline annual emission rates are summarized in Table 4-1 and detailed calculations can be found in Appendix A.

Table 4-1. Annual Baseline Emission Rates

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Total SO$_2$ Emissions (tpy)	373	347	2,854	3,008	6,582

5. SO₂ FOUR-FACTOR EVALUATION

The four-factor analysis is satisfied by conducting a stepwise review of emission reduction options in a top-down fashion. The steps are as follows:

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

Cost (Factor 1), timing for compliance (Factor 2), energy / non-air quality impacts (Factor 3), and remaining useful life (Factor 4), are all discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Additionally, operational feasibility and visibility impact considerations are also discussed as a part of this analysis. The baseline SO₂ emission rate that is used in the SO₂ four-factor analysis is summarized in Table 4-1.

5.1 Step 1: Identify all Available Retrofit Control Technologies

SO₂ is generated during fuel combustion in the lime kilns, as the sulfur in the fuel is oxidized by oxygen in the combustion air. Sulfur in the raw material (limestone) can also contribute to a kiln's SO₂ emissions, though the proportion of sulfur contained in the raw material is significantly less than that of the fuel.

Step 1 of the top-down control review is to identify available retrofit control options for SO₂. The available SO₂ retrofit control technologies for the Facility's kilns are summarized in Table 5-1 and are based on a review of potentially applicable flue gas desulfurization (FGD) technologies and the U.S. EPA RBLC database. The retrofit controls include both add-on controls that eliminate SO₂ after it is formed and switching to lower sulfur fuels which reduces the amount of sulfur added to the process.

Table 5-1. Available SO₂ Control Technologies

Dry Sorbent Injection
Alternative Fuel Scenarios
Wet FGD Scrubbing
Semi-Wet/Dry FGD Scrubbing

An important detail to consider is existing add-on and inherent controls on the lime kilns at the Facility. Kilns 1 and 2 have an add-on scrubber system which controls PM and SO₂ emissions. All kilns have a small amount of inherent control due to the presence of large volumes of alkaline materials in the system. However, due to design differences in the case of the Facility's lime kilns those inherent control efficiencies are much lower when compared to other lime kiln operations. Inherent SO₂ control results in sulfur exiting the kiln via the product and the lime kiln dust (LKD) or lime kiln sludge (LKS). Additionally, due to operational differences, Kilns 1 and 2 have different inherent control profiles than Kilns 3 and 4. See Appendix A for detailed control efficiency assumptions for all kilns. These existing controls are reflected in the baseline emission estimates in Table 4-1.

5.1.1 Alternative Fuel Scenarios

Fuels that can be considered for use in the lime kilns must have sufficient heat content, have dependable supply, and readily available locally in significant quantities so as to not disrupt continuous production. Also, they must not adversely affect product quality.

Currently, the Facility's kilns utilize a blend of natural gas, coal, and petroleum coke during normal operations. The allowable blends are dependent both on kiln technology, type of lime being produced, and market availability. Alternative lower-sulfur fuel scenarios that can be considered are maximum or increased coal usage, increased natural gas usage, and maximizing as well as switching to low sulfur coal.

In the case of fuels like diesel, there are no current known examples of rotary kilns that fire 100% diesel fuel for lime production. Therefore, the use of diesel fuel is not a commercially established emission reduction method and is not considered an available, feasible option at this time. In the case of using standard coal where petroleum coke was previously used, each kiln at the Facility has a maximum coal usage rate where, if exceeded, operational issues can occur. These operational issues include plugging and ash rings in the kiln. This results in the need to shutdown, clean, and restart the kiln, disrupting production and creating additional emissions from additional startup events needed for the kiln systems.[9] Such events can be very difficult to manage and address, as the cleaning process for the plugging issues must be managed properly to limit any potential damage to the kiln systems themselves, and to ensure proper safety of facility personnel.

This can also lead to significant down times for the kiln systems if the ash ring/plugging issue is too extensive, leading to potentially significant production-based revenue losses.

5.1.2 Dry Sorbent Injection

Dry sorbent injection (DSI) operates under a two-step process where first a sorbent (e.g. hydrated lime) is injected directly into the flue gas where it adsorbs SO_2 to create a dry waste product. In the second step, the calcium/sulfur waste product is removed using downstream particulate control.[10] In the case of Kilns 3 and 4, there is currently insufficient space (between existing kilns, baghouse systems, and the stack) to accommodate dry sorbent injection without complete removal of the existing baghouse controls system and installation of new equipment.

5.1.3 Wet FGD Scrubbing

A wet FGD scrubber is a tail pipe technology that may be installed downstream of the kilns. In a typical wet FGD scrubber, the flue gas flows upward through a reactor vessel that has an alkaline reagent flowing down from the top. The scrubber mixes the flue gas and alkaline reagent using a series of spray nozzles to distribute the reagent across the scrubber vessel. The calcium (or other alkaline reagent) in the reagent reacts with the SO_2 in the flue gas to form calcium sulfite and/or calcium sulfate that is removed with the scrubber sludge and is disposed. In the case of Kilns 3 and 4, there is currently insufficient space (between existing baghouse systems and the stack) to accommodate wet FGD scrubbing without complete removal of the existing baghouse controls system, and/or relocation of the combined Kiln 3 and Kiln 4 stack.

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[9] EPA August 20, 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Round", states that "*States may also determine that it is unreasonable to consider some fuel-use changes because they would be too fundamental to the operation and design of a source.*"

[10] EPA Air Pollution Control Technology Factsheet for Flue Gas Desulfurization (FGD).

Increased maintenance for the wet FGD scrubber system can also lead to significant down times for the kiln systems causing potentially significant production-based revenue losses.

5.1.4   Semi-Wet/Dry FGD Scrubbing

Semi-wet/dry FGD scrubbing uses a scrubber tower where atomized hydrated lime slurry is sprayed into the exhaust flue gas. The lime adsorbs the SO_2 in the exhaust and turns it into a powdered calcium/sulfur compound. A particulate control device removes the solid reaction products from the gas stream prior to releasing to the atmosphere. Semi-wet/dry FGD scrubbing operates under similar principles as wet FGD scrubbing, however, it is less effective and more costly.[11] As a result, Lhoist considers analysis of this control technology redundant since there would be no situation where semi-wet/dry FGD scrubbing would be preferred over wet FGD scrubbing at the Facility.

5.2   Step 2. Eliminate Technically Infeasible Control Technologies

Lhoist is conservatively considering three of the aforementioned SO_2 control technologies (dry sorbent injection, alternative fuel scenarios, wet FGD scrubbing) to be technically feasible and will continue the review of all three control technologies. Semi-wet/dry FGD scrubbing, although technically feasible, operates under similar principles as wet FGD scrubbing, however, it is less effective and more costly as noted in Section 5.1.4. Therefore, Lhoist considers further analysis of this control technology redundant and deems the analysis of the wet FGD scrubbing control method to be sufficient.

5.3   Step 3. Evaluate the Control Effectiveness of Remaining Control Technologies

This step examines the effectiveness of the aforementioned SO_2 control technologies in terms of control efficiency based on percent of input sulfur removed and/or change in SO_2 emissions. See Appendix A for detailed calculations on control effectiveness and emissions changes. Kilns 1 and 2 are currently equipped with wet scrubber systems for SO_2 and PM control. Kilns 3 and 4 are currently equipped with baghouses for PM control. All kilns have a small degree of inherent control due to the presence of alkaline materials in the system. Based on data collected by Lhoist as part of facility operations, approximately 10-20% of the input sulfur to the facility can be removed in the LKD, while 4-8% of the input sulfur to the facility can be present in the lime product.[12] While the control technologies discussed in this Section may present significant degrees of potential SO_2 reduction, it is important to consider that many of the control scenarios may not be economically or operationally feasible as discussed in Section 5.4 (Step 4). Additionally, Lhoist believes that no changes are necessary at the facility to meet the current reasonable progress goals for the Sipsey Wilderness Area under the Regional Haze Rule, as discussed in Section 5.5.

5.3.1   Alternative Fuel Scenarios

The alternative fuel scenarios considered are maximum or increased coal usage, increased natural gas usage, and maximizing low sulfur coal.

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[11] EPA Air Pollution Control Technology Factsheet for Flue Gas Desulfurization (FGD).

[12] Based on 2018/2019 lab analysis data as reviewed by Lhoist.

5.3.1.1 Maximum Coal Alternative Fuel Scenario

Maximizing standard coal usage relative to petroleum coke could reduce the input sulfur to the kilns via fuel as the standard coal type used at the Facility contains less sulfur than petroleum coke based on Lhoist sampling data. Table 5-2 shows the emissions changes that may result from switching all fuel (except for natural gas) to standard coal for all kilns.

Table 5-2. Emissions Changes from Maximum Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO$_2$ Emissions Difference (tpy)	-216	-198	-1,665	-1,755	-3,834

5.3.1.2 Increased Coal Alternative Fuel Scenario

Similar to maximizing coal, increasing standard coal usage relative to petroleum coke could also reduce the input sulfur to the kilns via fuel as standard coal used at the Facility contains less sulfur than petroleum coke based on Lhoist sampling data. Table 5-3 shows the emissions changes that may result from switching fuels (except for natural gas) to an 80% / 20% mix of standard coal and petroleum coke, respectively, for all kilns.

Table 5-3. Emissions Changes from Increased Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO$_2$ Emissions Difference (tpy)	-144	-129	-1,120	-1,181	-2,574

5.3.1.3 Increased Natural Gas Alternative Fuel Scenario

Increasing natural gas usage at the kilns relative to solid fuels like standard coal and petroleum coke could reduce the input sulfur to the kilns via fuel as natural gas contains minute amounts of sulfur compared to the solid fuels of standard coal and petroleum coke used at the Facility. Table 5-4 shows the emissions changes that may result from switching fuels to a 20% / 28% / 52% mix of natural gas, standard coal, and petroleum coke, respectively, for all kilns.

Table 5-4. Emissions Changes from Increased Natural Gas

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO$_2$ Emissions Difference (tpy)	-29	-20	-361	-380	-791

5.3.1.4 Maximum Low Sulfur Coal Alternative Fuel Scenario

Maximizing low sulfur coal usage relative to petroleum coke could reduce the input sulfur to the kilns via fuel as low sulfur coal contains less sulfur than both standard coal and petroleum coke used at the facility. Table 5-5 shows the emissions changes that may result from switching all fuel (except for natural gas) to low sulfur coal for all kilns.

Table 5-5. Emissions Changes from Maximum Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO$_2$ Emissions Difference (tpy)	-281	-260	-2,158	-2,275	-4,973

5.3.2 Dry Sorbent Injection

Two dry sorbent injection scenarios are considered for the Facility. One scenario is the replacement of the existing wet scrubbers at Kilns 1 and 2 with an injection system for hydrated lime and state-of-the-art baghouse system at each kiln. The second scenario is the replacement of the existing baghouse systems at Kilns 3 and 4 with a new state-of-the-art baghouse system as well as the installation of an injection system for hydrated lime at each kiln.[13] Both scenarios would provide SO_2 and PM control for the kilns.

5.3.2.1 Kilns 1 and 2 Dry Sorbent Injection

Replacing the existing wet scrubbers on Kilns 1 and 2 with new baghouses and hydrated lime injection systems would not provide better SO_2 control for the kilns. The current scrubber control efficiency for each kiln is estimated to be 75% based on percent of input sulfur removed by the scrubber. The control efficiency for a hydrated lime injection system with baghouse is estimated to be 50%.[14] As Table 5-6 shows, the installation of this control technology would result in the increase of SO_2 emissions.

Table 5-6. Emissions Changes from Kilns 1 and 2 Dry Sorbent Injection

	Kiln 1	Kiln 2	Total
SO_2 Emissions Difference (tpy)	+663	+617	+1,279

5.3.2.2 Kilns 3 and 4 Dry Sorbent Injection

Replacing the existing baghouses on Kilns 3 and 4 with new baghouses and hydrated lime injection systems could reduce SO_2 emissions by removing input sulfur to the kiln via the hydrated lime. The control efficiency for a hydrated lime injection system with baghouse is estimated to be 50%.[15] Currently, there are no add-on controls for SO_2 at Kilns 3 and 4. Table 5-7 shows the emissions changes that may result from the installation of this control technology.

Table 5-7. Emissions Changes from Kilns 3 and 4 Dry Sorbent Injection

	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-1,427	-1,504	-2,931

5.3.3 Wet FGD Scrubbing

Two Wet FGD Scrubbing scenarios are considered for the Facility. One scenario is the replacement of the existing wet scrubbers at Kilns 1 and 2 with new state-of-the-art wet FGD scrubber systems optimized for PM and SO_2 control. The second scenario is the replacement of the existing baghouse systems for Kilns 3 and 4 with new state-of-the-art wet FGD scrubber systems similarly optimized for PM and SO_2 control.

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[13] The current baghouse systems for Kilns 3 and 4 would not be able to handle the additional load from the injection of hydrated lime. They would need to be replaced with new, properly sized baghouses.

[14] Per the April 2017 Final Report, *Dry Sorbent Injection for SO2/HCl Control Cost Development Methodology*, by Sargent & Lundy, LLC, funded by the U.S. EPA.

[15] Per the April 2017 Final Report, *Dry Sorbent Injection for SO2/HCl Control Cost Development Methodology*, by Sargent & Lundy, LLC, funded by the U.S. EPA.

5.3.3.1 Kilns 1 and 2 Wet FGD Scrubbing

Replacing the existing wet scrubbers on Kilns 1 and 2 with new state-of-the-art wet FGD scrubber systems could provide incrementally better SO_2 control for the kilns. The current scrubber control efficiency for each kiln is estimated to be 75% based on percent of input sulfur removed by the scrubber, whereas the control efficiency for a new state-of-the-art wet FGD scrubber system is estimated to be up to 98%.[16] Table 5-8 shows the emissions changes that may result from the installation of new wet FGD scrubbers for Kilns 1 and 2.

Table 5-8. Emissions Changes from Kilns 1 and 2 Wet FGD Scrubbing

	Kiln 1	Kiln 2	Total
SO_2 **Emissions Difference (tpy)**	-332	-309	-640

5.3.3.2 Kilns 3 and 4 Wet FGD Scrubbing

Replacing the existing baghouse systems on Kilns 3 and 4 with new state-of-the-art wet FGD scrubber systems would provide better SO_2 control as currently Kilns 3 and 4 do not have add-on SO_2 controls. The control efficiency for a new wet FGD scrubber system is estimated to be up to 98%.[17] Table 5-9 shows the emissions changes that may result from the installation of new wet FGD scrubbers for Kilns 3 and 4.

Table 5-9. Emissions Changes from Kilns 3 and 4 Wet FGD Scrubbing

	Kiln 3	Kiln 4	Total
SO_2 **Emissions Difference (tpy)**	-2,797	-2,948	-5,745

5.4 Step 4. Evaluate Impacts and Document the Results

This Section discusses each of the four factors as they relate to the control technology scenarios being analyzed for the Facility. Additionally, important considerations related to operational feasibility are also discussed here. See Appendix A for detailed calculations on the costing of control methods / control equipment and cost effectiveness.

5.4.1 Maximum Coal Alternative Fuel Scenario

This control method involves maximizing standard coal usage relative to petroleum coke (switching all fuel, except for natural gas, to standard coal for all kilns).

5.4.1.1 Economic Impacts and Costs of Compliance

The main cost from this control scenario is in the form of increased fuel costs and revenue loss from downtime caused by operational issues with use of maximum coal. Standard coal is approximately 51% more expensive per million British thermal unit (MMBtu) of heat input compared to petroleum coke and would increase

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[16] From the Air Pollution Control Technology Fact Sheet for Flue Gas Desulfurization (2003). Considering upper range of values for control efficiency.

[17] From the Air Pollution Control Technology Fact Sheet for Flue Gas Desulfurization (2003). Considering upper range of values for control efficiency.

operational costs for Lhoist.[18] Costs are presented in Table 5-10 in terms of annualized cost per ton of SO_2 reduced.

Table 5-10. Cost Effectiveness of Maximum Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-216	-198	-1,665	-1,755	-3,834
Total Annualized Cost Difference	$1,561,483	$1,374,598	$2,996,955	$ 2,998,940	$8,931,976
Cost Effectiveness ($/ton reduced)	$ 7,229	$ 6,953	$ 1,800	$ 1,709	$ 2,330

5.4.1.2 Timing for Compliance

There is no significant time for compliance required for the maximum coal scenario. Lhoist would need to change fuel supply orders and expects that enough standard coal would be available to supply the Facility's kilns.

5.4.1.3 Energy and Non-Air Quality Environmental Impacts

Table 5-11 describes the difference in trace metals in petroleum coke and standard coal.

Table 5-11. Trace Metals Comparison of Petroleum Coke and Standard Coal

	Petroleum Coke[1] (ppm)	Standard Coal[2] (ppm)
Arsenic	0.3	9.2
Beryllium	1.5	1.1
Cadmium	< 0.1	0.6
Lead	0.6	6.8
Manganese	2.4	21.5
Mercury	< 0.001	0.2
Nickel	165-580	15.6

1. Based on average values from the presentation, *Mill Use of Petcoke as an Alternative Lime Kiln Fuel to Reduce Energy Costs*, at the 2006 TAPPI Forum on Energy.
https://www.tappi.org/content/pdf/events/06energy-papers/6-3.pdf

2. Based on average values from AP-42 Table 1.1-17, *Emission Factors for Trace Elements, POM, And HCOH from Uncontrolled Bituminous and Subbituminous Coal Combustion*, for pulverized coal, dry bottom. Converted using the Lhoist HHV for standard coal.

Maximizing coal usage could lead to higher amounts of harmful metals being released to the atmosphere such as arsenic, cadmium, lead, manganese, and mercury, which are all considered hazardous air pollutants (HAPs). Certain metal HAPs such as beryllium and nickel may see a reduction in emissions.

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[18] Based on Lhoist projections for fuel cost.

5.4.1.4 Remaining Useful Life of the Kilns

Lhoist does not expect the remaining useful life of the Facility's kilns to influence this analysis.

5.4.1.5 Operational Feasibility Considerations

Compared to petroleum coke, standard coal is a lower quality fuel in terms of energy content and contains more ash, possibly causing operational issues, and which could lead to increased PM_{10} and NO_X emissions (other visibility impairing pollutants). Table 5-12 describes the difference in fuel parameters such as higher heating value (HHV), moisture content, and ash content between petroleum coke and standard coal.

Table 5-12. Fuel Parameter Comparison of Petroleum Coke and Standard Coal

	Petroleum Coke[1]	Standard Coal[1]
HHV (MMBtu/ton)	29.1	26.8
Moisture (%)	5.7	6.5
Ash (%)	0.94	7.5

1. Based on values from Lhoist fuel sampling data.

As a result of the higher ash content, each kiln at the Facility has a maximum coal usage rate where, if exceeded, operational issues can occur. This results in the need to shutdown, clean, and restart the kiln, disrupting production and creating additional emissions from additional startup events needed for the kiln systems.[19] Such events can be very difficult to manage and address, as the cleaning process for the plugging issues must be managed properly to limit any potential damage to the kiln systems themselves, and to ensure proper safety of facility personnel.

This can also lead to significant down times for the kiln systems if the ash ring/plugging issue is too extensive, leading to potentially significant production based revenue losses.

5.4.1.6 Conclusion

While the maximum coal control scenario may seem feasible in terms of cost effectiveness for Kilns 3 and 4, the overall impact to production and product quality from switching over to coal would have a negative impact on facility operations. Additionally, the maximum coal control scenario may increase facility PM_{10} and NO_X emissions (other visibility impairing pollutants) and increase emissions of toxic HAPs of concern such as mercury, arsenic, and lead. Therefore, Lhoist does not consider switching to maximum coal a viable option for the Facility's kilns.

5.4.2 Increased Coal Alternative Fuel Scenario

Similar to the maximum coal scenario, this control method involves increasing standard coal usage relative to petroleum coke (switching fuels, except for natural gas, to an 80% / 20% mix of standard coal and petroleum coke, respectively, for all kilns).

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[19] EPA August 20, 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Round", states that "*States may also determine that it is unreasonable to consider some fuel-use changes because they would be too fundamental to the operation and design of a source.*"

5.4.2.1 Economic Impacts and Costs of Compliance

The main cost from this control scenario is in the form of increased fuel costs and revenue loss from downtime caused by operational issues with increased coal. Standard coal is approximately 51% more expensive per MMBtu of heat input compared to petroleum coke and would increase operational costs for Lhoist.[20] Costs are presented in Table 5-13 in terms of annualized cost per ton of SO_2 reduced.

Table 5-13. Cost Effectiveness of Increased Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-144	-129	-1,120	-1,181	-2,574
Total Annualized Cost Difference	$1,365,608	$1,188,265	$2,689,171	$ 2,674,484	$7,917,528
Cost Effectiveness ($/ton reduced)	$ 9,483	$ 9,198	$ 2,401	$ 2,265	$ 3,076

5.4.2.2 Timing for Compliance

There is no significant time for compliance required for the increased coal scenario. Lhoist would need to change fuel supply orders and expects that enough standard coal would be available to supply the Facility's kilns.

5.4.2.3 Energy and Non-Air Quality Environmental Impacts

As described in Subsection 5.4.1.3, increasing standard coal usage relative to petroleum coke could lead to potentially higher amounts of harmful metal HAPs being released to the atmosphere such as arsenic, cadmium, lead, manganese, and mercury. Certain trace metal HAPs such as beryllium and nickel may see a reduction in emissions.

5.4.2.4 Remaining Useful Life of the Kilns

Lhoist does not expect the remaining useful life of the Facility's kilns to influence this analysis.

5.4.2.5 Operational Feasibility Considerations

As discussed in Subsection 5.4.1.5, compared to petroleum coke, standard coal is a lower quality fuel in terms of energy content and contains more ash, which could lead to increased PM_{10} and NO_X emissions (other visibility impairing pollutants). As a result of the higher ash content, each kiln at the Facility has a maximum coal usage rate where, if exceeded, operational issues can occur. This results in the need to shutdown, clean, and restart the kiln, disrupting production and creating additional emissions from additional startup events needed for the kiln systems.[21] Such events can be very difficult to manage and address, as the cleaning process for the plugging issues must be managed properly to limit any potential damage to the kiln systems themselves, and to ensure proper safety of facility personnel.

This can also lead to significant down times for the kiln systems if the ash ring/plugging issue is too extensive, leading to potentially significant production-based revenue losses.

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[20] Based on Lhoist projections for fuel cost.

[21] EPA August 20, 2019 "Guidance on Regional Haze State Implementation Plans for the Second Implementation Round", states that "*States may also determine that it is unreasonable to consider some fuel-use changes because they would be too fundamental to the operation and design of a source.*"

5.4.2.6   Conclusion

Lhoist deems this control scenario to be economically infeasible as the overall impact to production and product quality from switching over to increased coal would have a negative impact on facility operations. Additionally, the increased coal control scenario may increase facility PM_{10} and NO_X emissions (other visibility impairing pollutants) and increase emissions of toxic HAPs of concern such as mercury, arsenic, and lead. Therefore, Lhoist does not consider switching to increased coal a viable option for the Facility's kilns.

5.4.3   Increased Natural Gas Alternative Fuel Scenario

This control method involves increasing natural gas usage at the kilns relative to solid fuels like standard coal and petroleum coke by implementing a 20% / 28% / 52% mix of natural gas, standard coal, and petroleum coke, respectively, for all kilns.

5.4.3.1   Economic Impacts and Costs of Compliance

Annual costs from this control scenario are in the form of increased fuel costs. Natural gas is approximately 88% more expensive per MMBtu of heat input compared to petroleum coke and approximately 25% more expensive per MMBtu of heat input compared to standard coal.[22] This shift in fuel mix would result in increased annual costs for Lhoist.

Up to a 20% usage of natural gas is assessed, as any increase in natural gas usage of greater than 20% for the Facility's kilns (particularly for Kilns 3 and 4) is not feasible without additional evaluation and testing, and additional significant capital expenses. There would be significant capital costs associated with the upgrading of natural gas supply lines to the facility and the completion of kiln burner modifications to handle the increased natural gas usage. Many of these costs would be incurred by natural gas suppliers, as the current natural gas supply pipeline for the Facility is incapable of providing the necessary natural gas to run all of the Facility's kilns on increased capacities of natural gas (> 20%). Additional compression/installation of a new gas supply pipeline would be necessary to accomplish that goal. Currently, due to the uncertain nature of these capital costs, usages of natural gas beyond 20% are not quantified for this control scenario.

Costs are presented in Table 5-14 in terms of annualized cost per ton of SO_2 reduced.

Table 5-14. Cost Effectiveness of Increased Natural Gas

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-29	-20	-361	-380	-791
Total Annualized Cost Difference	$ 114,825	$ 81,926	$ 280,844	$ 296,056	$ 773,651
Cost Effectiveness ($/ton reduced)	$ 3,924	$ 4,088	$ 778	$ 778	$ 979

5.4.3.2   Timing for Compliance

The Facility is currently capable of increased natural gas usage up to 20% on the Kilns, particularly for Kilns 3 and 4. The timing for compliance for any increased natural gas scenario (> 20%) is highly uncertain. To achieve the needed level of supply for increased natural gas usage beyond 20%, Lhoist would have to negotiate and fund an agreement with the natural gas supplier to construct additional capacity to the Facility. Whether or not this is agreed to or possible from the perspective of the supplier is unknown at this time. It is also unknown how long this process would take. Furthermore, if supply can be increased, Lhoist would need

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[22] Based on Lhoist projections for fuel cost.

to upgrade its natural gas systems to handle the additional supply and make modifications to the kilns to utilize the increased natural gas supply (e.g., burner modifications).

5.4.3.3 Energy and Non-Air Quality Environmental Impacts

Lhoist does not anticipate significant direct energy or non-air quality impacts from increased natural gas usage.

5.4.3.4 Remaining Useful Life of the Kilns

Lhoist does not expect the remaining useful life of the Facility's kilns to influence this analysis.

5.4.3.5 Operational Feasibility Considerations

Depending on the way increased natural gas would be combusted, there is potential for increased NO_x emissions from the kilns (another visibility impairing pollutant). As mentioned previously, it is uncertain if natural gas supply can be expanded beyond the capability of >20% usage in the Kilns. Additionally, if natural gas usages were expanded beyond 20%, process downtime would be required to make natural gas system upgrades and burner modifications to the kilns resulting in lost production and potentially reduced or unusable product quality while the kilns are optimized to utilize the new fuel mix and modified burners.

5.4.3.6 Conclusion

The increased natural gas control scenario seems feasible in terms of cost effectiveness for Kilns 3 and 4, and the current natural gas supply for the facility is sufficient to run those Kilns on up to 20% natural gas. Therefore, for Kilns 3 and 4, increased natural gas usage up to 20% could be technically and economically feasible.

5.4.4 Maximum Low Sulfur Coal Alternative Fuel Scenario

This control method involves maximizing low sulfur coal usage relative to standard coal and petroleum coke (switching all fuel, except for natural gas, to low sulfur coal for all kilns). For purposes of this analysis, low sulfur coal is presumed to be representative of available Appalachian coal.

5.4.4.1 Economic Impacts and Costs of Compliance

Operational costs from this control scenario are in the form of increased fuel costs and revenue loss from downtime caused by operational issues with increased coal. Low sulfur coal is approximately 73% more expensive per MMBtu of heat input compared to petroleum coke and approximately 14% more expensive per MMBtu of heat input compared to standard coal.[23] This shift in fuel mix would result in increased operational costs for Lhoist. Costs are presented in Table 5-15 in terms of annualized cost per ton of SO_2 reduced.

Table 5-15. Cost Effectiveness of Maximum Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO₂ Emissions Difference (tpy)	-281	-260	-2,158	-2,275	-4,973
Total Annualized Cost Difference	$1,981,601	$1,774,253	$3,657,102	$ 3,694,845	$11,107,801
Cost Effectiveness ($/ton reduced)	$ 7,050	$ 6,834	$ 1,695	$ 1,624	$ 2,234

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[23] Based on Lhoist projections for fuel cost and quoted fuel costs.

5.4.4.2   Timing for Compliance

Lhoist has concerns about the long term availability and stability of the supply of low sulfur coal (e.g., Appalachian coal) for the Montevallo facility. Lhoist would need time to procure contracts for a continuous supply of this type of fuel and ensure it will be available in the future for the Facility.

5.4.4.3   Energy and Non-Air Quality Environmental Impacts

Maximizing low sulfur coal usage relative to petroleum coke or standard coal could lead to potentially higher amounts of harmful metal HAPs being released to the atmosphere such as arsenic, beryllium, cadmium, manganese, and mercury. Certain metal HAPs such as nickel may see a reduction in emissions. Table 5-16 describes this comparison in more detail. Additionally, Appalachian coal can be produced via mountaintop mining which is known to have determinantal environmental impacts.

Table 5-16. Trace Metals Comparison of Petroleum Coke, Standard Coal, and Low Sulfur Coal

	Petroleum Coke[1] (ppm)	Standard Coal[2] (ppm)	Low Sulfur Coal[3] (ppm)
Arsenic	0.3	9.2	76.8
Beryllium	1.5	1.1	2.3
Cadmium	< 0.1	0.6	0.1
Lead	0.6	6.8	7.3
Manganese	2.4	21.5	37.5
Mercury	< 0.001	0.2	0.2
Nickel	165-580	15.6	18.0

1. Based on average values from the presentation, *Mill Use of Petcoke as an Alternative Lime Kiln Fuel to Reduce Energy Costs*, at the 2006 TAPPI Forum on Energy.
https://www.tappi.org/content/pdf/events/06energy-papers/6-3.pdf

2. Based on average values from AP-42 Table 1.1-17, *Emission Factors for Trace Elements, POM, And HCOH from Uncontrolled Bituminous and Subbituminous Coal Combustion*, for pulverized coal, dry bottom. Converted using the Lhoist HHV for standard coal.

3. Based on average values from the USGS COALQUAL database for Alabama based Appalachian coal samples.
https://ncrdspublic.er.usgs.gov/coalqual/

5.4.4.4   Remaining Useful Life of the Kilns

Lhoist does not expect the remaining useful life of the Facility's kilns to influence this analysis.

5.4.4.5   Operational Feasibility Considerations

Compared to petroleum coke and standard coal, low sulfur coal is an even lower quality fuel in terms of energy content and contains more ash than both petroleum coke and standard coal, and these factors could lead to increased emissions of PM_{10} and NO_X (other visibility impairing pollutants). Table 5-17 describes the difference in fuel parameters such as higher heating value (HHV), moisture content, and ash content between the three fuels.

Table 5-17. Fuel Parameter Comparison of Solid Fuels

	Petroleum Coke[1]	Standard Coal[1]	Low Sulfur Coal[1]
HHV (MMBtu/ton)	29.1	26.8	25.9
Moisture (%)	5.7	6.5	7.1
Ash (%)	0.94	7.5	7.8

1. Based on values from Lhoist fuel sampling data.

As a result of the higher ash content than other fuels, the kilns at the Facility would quickly experience operational issues such as plugging and ash rings in the kiln. Resulting in the need to shutdown, clean, and restart the kiln, disrupting production and creating additional emissions. Additionally, it is unclear if the Facility's kilns can actually run and achieve steady state operation at sufficient production levels with this type of lower quality fuel to meet the necessary product quality expected.

5.4.4.6 Conclusion

While the maximum low sulfur coal control scenario may seem feasible in terms of cost effectiveness for Kilns 3 and 4, the long-term availability of the fuel is unknown and the overall impact to production and product quality from the low sulfur coal would have a negative impact on facility operations. Additionally, the maximum low sulfur coal control scenario may increase facility PM_{10} and NO_x emissions (other visibility impairing pollutants) and could increase emissions of toxic HAPs of concern such as mercury and arsenic. Therefore, Lhoist does not consider switching to low sulfur coal a viable option for the Facility's kilns.

5.4.5 Kilns 1 and 2 Dry Sorbent Injection

This control method involves replacing the existing wet scrubbers on Kilns 1 and 2 with new baghouses and dry sorbent injection systems. As this control method would actually lead to increased SO_2 emissions, it is not a beneficial option for SO_2 control and not discussed further.

5.4.6 Kilns 3 and 4 Dry Sorbent Injection

This control method involves replacing the existing baghouses on Kilns 3 and 4 with new baghouses and dry sorbent injection systems which could reduce SO_2 emissions by removing input sulfur to the kiln via the hydrated lime sorbent.

5.4.6.1 Economic Impacts and Costs of Compliance

Annual costs from this control method include costs from the injection system and the baghouse. Injection system costs include labor, maintenance, hydrated lime, and power.[24] Baghouse costs are summarized as well as operation and maintenance (O&M costs).[25] Indirect annual costs such as overhead, administrative charges, property tax, and insurance are also included.[26]

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[24] Based on April 2017 Final Report, *Dry Sorbent Injection for SO2/HCl Control Cost Development Methodology*, by Sargent & Lundy, LLC, funded by the U.S. EPA.

[25] Based on the Air Pollution Control Technology Fact Sheet for Pulse-Jet Cleaned Type Fabric Filters (2003).

[26] Indirect annual costs based on EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.4.

Capital costs for the injection system and baghouse are described in detail in Appendix A. These capital costs are annualized and included along with the annual costs to determine the total annualized cost. Costs are presented in Table 5-18 in terms of annualized cost per ton of SO_2 reduced.

Table 5-18. Cost Effectiveness of Kilns 3 and 4 Dry Sorbent Injection

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	0	0	-1,427	-1,504	-2,931
Total Annualized Cost Difference	$ -	$ -	$ 6,506,219	$ 6,447,018	$ 12,953,237
Cost Effectiveness ($/ton reduced)	N/A	N/A	$ 4,560	$ 4,286	$ 4,419

5.4.6.2 Timing for Compliance

Timing for compliance for this control method involves process downtime for the demolition of the current baghouse and stack, as well as the construction of the injection systems, new baghouses, and ancillary equipment. Due to this process downtime, Lhoist would not only be paying for the new equipment, but there would also be significant revenue loss due to process downtime.

5.4.6.3 Energy and Non-Air Quality Environmental Impacts

In terms of negative energy and non-air quality environmental impacts, this control method would result in increased power usage and waste generation (in the form of spent hydrated lime). This would lead to an increased load of sulfur through the facility waste system, incurring significant additional waste handling and management based costs. Lhoist does not anticipate any other significant direct impacts from dry sorbent injection.

5.4.6.4 Remaining Useful Life of the Kilns

Lhoist does not expect the remaining useful life of the Facility's kilns to influence this analysis.

5.4.6.5 Operational Feasibility Considerations

The Kilns 3 and 4 dry sorbent injection control scenario may cause an increase in emissions of PM_{10} (another visibility impairing pollutant) due to the large amount of sorbent being injected into the flue gas. Additionally, the downtime associated with demolition, clean up, stack modifications, auxiliary construction, and the installation of the injection systems and new baghouses would negatively impact facility operations.

5.4.6.6 Conclusion

Lhoist deems the Kilns 3 and 4 dry sorbent injection control scenario to be economically infeasible. Additionally, costs related to demolition, clean up, and stack modifications, as well as the downtime and subsequent production loss required during construction, are not included in the costing estimates and would only drive up the expense for this scenario.

5.4.7 Kilns 1 and 2 Wet FGD Scrubbing

This control method involves replacing the existing wet scrubbers on Kilns 1 and 2 with new state-of-the-art wet FGD scrubber systems to provide incrementally better SO_2 control for the kilns.

5.4.7.1 Economic Impacts and Costs of Compliance

Annual costs from this control method are summarized as well as costs due to revenue loss from increased downtime and O&M costs.[27] Indirect annual costs such as overhead, administrative charges, property tax, and insurance are also included.[28]

Capital costs for the wet FGD scrubbing system are described in Appendix A. These capital costs are annualized and included along with the annual costs to determine the total annualized cost. Costs are presented in Table 5-19 in terms of annualized cost per ton of SO_2 reduced.

Table 5-19. Cost Effectiveness of Kilns 1 and 2 Wet FGD Scrubbing[29]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-332	-309	0	0	-640
Total Annualized Cost Difference	$ 4,992,897	$ 4,844,624	$ -	$ -	$ 9,837,521
Cost Effectiveness ($/ton reduced)	$ 15,056	$ 15,702	N/A	N/A	$ 15,368

5.4.7.2 Timing for Compliance

Timing for compliance for this control method involves process downtime for the demolition of the current wet scrubbers, construction of the new wet FGD scrubbers, and auxiliary construction such as stack modifications. Due to this process downtime, Lhoist would not only be paying for the new equipment, but there would also be significant revenue loss due to process downtime.

5.4.7.3 Energy and Non-Air Quality Environmental Impacts

In terms of negative energy and non-air quality environmental impacts, this control method would result in increased power usage, waste generation (in the form of scrubber sludge and wastewater), and water usage. Lhoist does not anticipate any other significant direct impacts from wet FGD scrubbing.

5.4.7.4 Remaining Useful Life of the Kilns

Lhoist does not expect the remaining useful life of the Facility's kilns to influence this analysis.

5.4.7.5 Operational Feasibility Considerations

The Kilns 1 and 2 wet FGD scrubbing control scenario may be difficult to implement due to space concerns as wet FGD scrubbers are larger than the existing wet scrubbers. Auxiliary modifications to the kilns or stack would likely be required to fit the control devices. Additionally, the downtime associated with demolition, clean up, stack modifications, auxiliary construction, and the installation of the new wet FGD scrubbers would negatively impact facility operations. No cost penalty for construction related downtime is currently considered in the evaluation of cost effectiveness for this option. Also, expanded scrubber systems would add additional solid waste and wastewater handling for the facility operations, leading to increased waste handling costs. Additional wastewater loading would increase the overall sulfate loading to facility water treatment systems, influencing water management and water discharges from facility operations, potentially jeopardizing current facility sulfate and total dissolved solids water discharge limits.

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[27] Based on the Air Pollution Control Technology Fact Sheet for Flue Gas Desulfurization (2003).

[28] Indirect annual costs based on EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.4.

[29] SO_2 emissions difference compared to baseline emissions with existing add-on controls.

5.4.7.6   Conclusion

Lhoist deems the Kilns 1 and 2 wet FGD scrubbing control scenario to be economically infeasible. Additionally, costs related to demolition, clean up, and stack modifications, as well as the downtime and subsequent production loss required during construction, are not included in the costing estimates and would only drive up the expense for this scenario.

5.4.8   Kilns 3 and 4 Wet FGD Scrubbing

This control method involves replacing the existing baghouses on Kilns 3 and 4 with new state-of-the-art wet FGD scrubber systems to provide PM and SO_2 control for the kilns.

5.4.8.1   Economic Impacts and Costs of Compliance

Annual costs from this control method are summarized as well as O&M costs.[30] Indirect annual costs such as overhead, administrative charges, property tax, and insurance are also included.[31]

Capital costs for the wet FGD scrubbing system are described in Appendix A. These capital costs are annualized and included along with the annual costs to determine the total annualized cost. Costs are presented in Table 5-20 in terms of annualized cost per ton of SO_2 reduced.

Table 5-20. Cost Effectiveness of Kilns 3 and 4 Wet FGD Scrubbing[32]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 **Emissions Difference (tpy)**	0	0	-2,797	-2,948	-5,745
Total Annualized Cost Difference	$ -	$ -	$ 6,473,488	$ 6,472,728	$12,946,216
Cost Effectiveness ($/ton reduced)	N/A	N/A	$ 2,315	$ 2,195	$ 2,253

5.4.8.2   Timing for Compliance

Timing for compliance for this control method involves process downtime for the demolition of the current baghouse systems and stacks and the construction of the new wet FGD scrubbers and stacks. Due to this process downtime, Lhoist would not only be paying for the new equipment, but there would also be significant revenue loss due to process downtime.

5.4.8.3   Energy and Non-Air Quality Environmental Impacts

In terms of negative energy and non-air quality environmental impacts, this control method would result in increased power usage, waste generation (in the form of scrubber sludge and wastewater), and water usage. Lhoist does not anticipate any other significant direct impacts from wet FGD scrubbing.

5.4.8.4   Remaining Useful Life of the Kilns

Lhoist does not expect the remaining useful life of the Facility's kilns to influence this analysis.

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[30] Based on the Air Pollution Control Technology Fact Sheet for Flue Gas Desulfurization (2003).

[31] Indirect annual costs based on EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.4.

[32] SO_2 emissions difference compared to baseline emissions with existing add-on controls.

5.4.8.5 Operational Feasibility Considerations

The Kilns 3 and 4 wet FGD scrubbing control scenario may be difficult to implement due to space concerns as wet FGD scrubbers are larger than the baghouse systems. Significant modifications to the kilns and stacks would likely be required to fit the control devices. Additionally, the downtime associated with demolition, clean up, stack modifications, auxiliary construction, and the installation of the new wet FGD scrubbers would negatively impact facility operations. No cost penalty for construction related downtime is currently considered in the evaluation of cost effectiveness for this option. Also, expanded scrubber systems would add additional solid waste and wastewater handling for the facility operations, leading to increased waste handling costs. Additional wastewater loading would increase the overall sulfate loading to facility water treatment systems, influencing water management and water discharges from facility operations, potentially jeopardizing current facility sulfate and total dissolved solids water discharge limits.

5.4.8.6 Conclusion

As further discussed in Sections 5.5 and 5.6, while the Kilns 3 and 4 wet FGD scrubbing control scenario may seem cost effective, the high costs and downtime associated with implementation of this emissions control method, economic issues for the industry, lack of direct evidence of significant visibility improvement at the Sipsey Wilderness Area due to these emissions reductions, and no need for any emissions reductions from this source to meet reasonable progress for the Sipsey Wilderness Area at this time, Lhoist does not consider addition of wet FGD scrubbing on Kilns 3 and 4 feasible for visibility improvements at the Sipsey Wilderness Area as part of this implementation period.

5.5   Visibility Impact Considerations

This section addresses additional items of potential concern, which should be considered as part of the analysis and whether emissions reductions/add-on controls for the Facility are necessary as part of this second implementation period.

5.5.1   Visibility Conditions at Sipsey

While not directly part of the four-factor analysis, there are additional factors that can be considered by regulatory agencies when evaluating if actions is necessary to implement emissions controls/reductions at various facilities. From the EPA Guidance on Regional Haze State Implementation Plans for the Second Implementation Period, August 20, 2019 (page 22), one of the five additional factors to consider for selection of sources for the four-factor analysis includes:
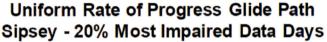
> Section 51.308(f)(2)(iv)(E) of the Regional Haze Rule -The anticipated net effect on visibility due to projected changes in point, area, and mobile source emissions over the period addressed by the long-term strategy
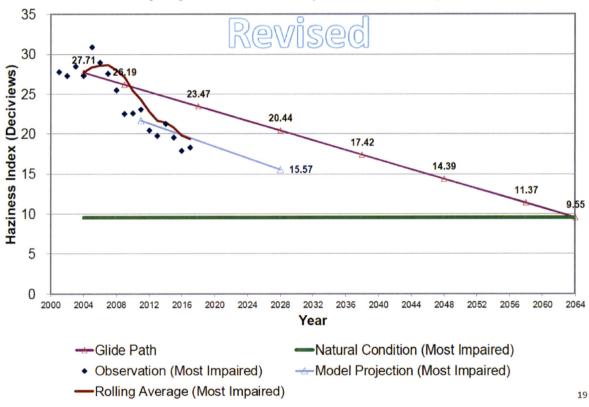
As further explained in that section of the document:

> The fact that visibility conditions in 2028 will be on or below the URP glidepath is not a sufficient basis by itself for a state to select no sources for analysis of control measures; however, the state may consider this information when selecting sources. See the final rule preamble discussion of this subject at 82 FR 3078 at 3093 and 3099-3100, January 10, 2017. Rather, that fact would serve to demonstrate that, after a state has gone through its source selection and control measure analysis, it has no "robust demonstration" obligation per 40 CFR 51.308(f)(3)(ii)(A) and/or (B).

While this passage references more directly whether a source should be considered for a four-factor analysis or not, it is still relevant towards whether implementation of any emissions controls/reductions for pertinent sources should be considered. All current information for the Class I area of concern for this analysis, the Sipsey Wilderness, indicates that the glidepath for 2028 is being met. In fact, data provided as part of the May 2020 VISTAS stakeholder briefing indicated that modeling demonstrated that Sipsey was more than 10 years ahead of its glidepath schedule. In fact, data also provided as part of that presentation indicated that actual observations (from available monitoring data) on the most impaired days indicated a rate of progress higher than that predicted by the modeling.[33] A copy of the Uniform Rate of Progress Glide Path drawing shown as part of the May 2020 VISTAS presentation, is shown below in Figure 1.

Figure 1. Sipsey Wilderness May 2020 VISTAS Presentation Sipsey URP Glide Path

Based on the fact that the Sipsey Wilderness Area is already meeting the required 2028 glide path goals for this planning period, there should be no required action for the Facility at this time to meet the glide path goals for this planning period.

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[33] The IMPROVE monitoring network collects samples from an IMPROVE monitor established at the Black Warrior Work Center north of Grayson, Alabama in 1992 to assess visibility impairment in the Sipsey Wilderness Area.

5.5.2 AOI Screening Selection of the Facility

It is unclear if a four-factor analysis would have been required of Lhoist if the initial facility screening had utilized the appropriate SO_2 tpy emissions for 2028 as part of the analysis. Procedurally, in Alabama those sources whose overall combined sulfates contribution for 2028 was more than 2% to visibility impairment as part of the AOI screening step, then that source was chosen for specific source apportionment modeling (PSAT) as a refined modeling step to further evaluate the contributions from that source with regards to visibility impairment. If the sulfate contribution from that source was then found to be greater than 1% as part of the PSAT modeling, then those sources were selected to conduct a four-factor analysis.

Since the Facility was inadvertently left out of the PSAT modeling, the 2.69% screening value for the site (when applying a more accurate 2028 SO_2 emissions project of 9,490 tpy) was then arbitrarily applied to the 1% threshold (from the refined PSAT step that the Facility was not a part of), and Lhoist was then by default asked to conduct a four-factor analysis.

Therefore, there is some uncertainty as to whether or not inclusion of the Facility into the PSAT modeling would have indicated that a four-factor analysis would have been required or not for the site.

Data provided by SESARM from the screening step for the Sipsey Wilderness,[34] as well as the May 2020 VISTAS stakeholder briefing (Appendix B), allowed for the creation of Table 5-21, comparing the initial screening values and final PSAT modeling sulfate contributions derived for eight identified sites of interest by VISTAS.

Table 5-21. Comparison of Screening and PSAT Results for Sipsey Sites of Interest

State	Facility Name	Screening Result (% Sulfate Contribution)	PSAT Result (% Sulfate Contribution)	Difference
KY	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	3.31%	2.22%	1.09%
OH	General James M. Gavin Power Plant	0.38%	1.99%	-1.61%
IN	Indiana Michigan Power DBA AEP Rockport	5.72%	1.99%	3.73%
IN	Gibson	2.84%	1.65%	1.19%
IN	Indianapolis Power & Light Petersburg	1.72%	1.57%	0.15%
TN	TVA Cumberland Fossil Plant	3.18%	1.48%	1.70%
MO	New Madrid Power Plant - Marston	3.48%	1.34%	2.14%
KY	Big Rivers Electric Corp - Wilson Station	1.99%	1.29%	0.70%

For Lhoist to have been determined to have not been required to conduct a four-factor analysis, the PSAT refined modeling result would have had to have been less than 1% sulfate contribution. As can be seen from the results above, all sites but one experienced a decrease in refined results from the original screening step. For the Facility's PSAT results to be below 1%, a greater than 1.69% decrease would have been necessary

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[34] https://www.metro4-sesarm.org/content/task-5-area-influence-analysis

(from screening results) if they were included in the refined modeling step. This does not seem unachievable, since three of the eight sites of interest identified by VISTAS for Sipsey had decreases from the screening result to the PSAT contribution of more than 1.69%.

While much of this is perhaps circumstantial evidence, it is worth noting that had the Facility originally been included in the PSAT modeling, there is no direct evidence (as proven out by the table above) that modeled impacts from the PSAT modeling would have shown greater than 1% sulfate contribution to visibility impairment thus requiring a four-factor analysis.[35]

It is also worth noting that per the VISTAS stakeholder briefing from May 2020, and as evidenced by the sources of interest evaluated by VISTAS for PSAT modeling, that LADCO States, and States from other regions, had more influence on sulfate and visibility impairment on the Sipsey Wilderness Area than facilities within the State of Alabama. More than half of the contribution to visibility impairment at Sipsey is coming from sources in States in the Central and Great Lakes regions of the United States. This is further evidenced by the sites listed in Table 5-21 which were evaluated through PSAT modeling, as many of the sources of interest identified fell within these regional areas. The following Figure 2, taken from the May 2020 VISTAS stakeholder briefing (Appendix B), illustrates this. Therefore, it would seem that more visibility improvement within the Sipsey Wilderness Area could be achieved through focusing on reduction of the sulfate contributions to visibility impairment from these regional areas.

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[35] While no direct evidence towards current % sulfate contribution from the Facility, as part of the first planning period for Regional Haze the Facility was evaluated and found to not be subject to BART because the BART-eligible emission units at the Montevallo Plant (Kilns 1, 3, and 4) were found to not significantly contribute to visibility impairment at any Class I areas.
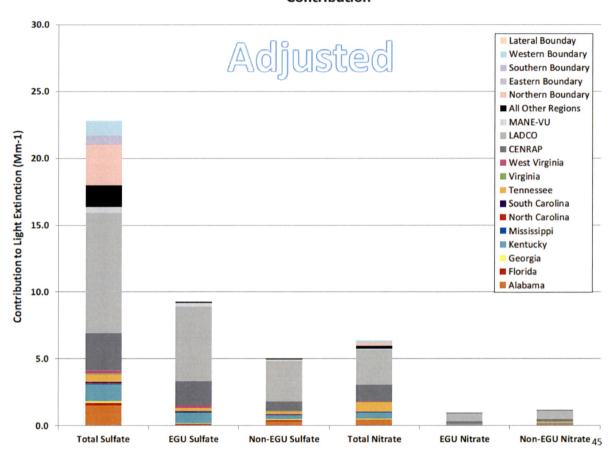
Figure 2. Sipsey Wilderness May 2020 VISTAS Presentation Sipsey State/Regional Contribution

5.5.3 Facility Emission Estimates Consideration

Another consideration point is the accuracy of emission estimates from Kilns 3 and 4 for the Facility. There are two factors for consideration which would have some potential influence on emissions of SO_2 from Kilns 3 and 4.

► Basis of current emission estimates for Kilns 3 and 4 for SO_2 emissions
► A portion of the stack gas from the Kiln 3/4 combined stack is vented to a scrubber system for water treatment at the Facility

The currently reported emissions inventory information for the Facility for SO_2 emissions from Kilns 3 and 4 is based on emissions studies of the Kilns in preparation for the Kiln 5 vertical kiln PSD permitting project in 2014. The Kilns in question were not being run as effectively at that time, with higher than nominal fuel flows being used within the Kilns. More recent measurements/observations from the Kiln 3 and 4 stacks infer that current emissions estimates for Kilns 3 and 4 could be overestimated by several thousand tons. As the Kilns have never been required to adhere to stringent emission limits, and SO_2 emission estimates are currently based on short term stack-based measurements, the long term ton/yr performance of Kilns 3 and 4 in regards to SO_2 emissions is not clearly known.

Therefore, it is possible that current kiln tpy emission estimates for Kiln 3 and Kiln 4 could be overestimated. Estimated emissions, based on a more long term mass balance approach, would seem to support the historic overestimation of Facility SO_2 emissions. It is possible that had more accurate emissions been estimated for the Facility, it would have "screened out" of the AOI screening step described above.

Also, after the point of historic measurement of emissions of SO_2 from the combined Kilns 3 and 4 stack, a portion of the gas stream is extracted from the Kiln 3 and 4 combined stack and fed into the facility water treatment system, where the exhaust gas stream passes through a scrubber system (for water treatment purposes). However, this system is also effectively scrubbing the SO_2 out of that portion of the exhaust gas stream. The amount of SO_2 controlled/extracted by this system has never been fully evaluated, or taken credit for, as part of any air permitting actions by the Facility. This is further support for the fact that the current kiln tpy emission estimates for Kilns 3 and 4 are likely overestimated.

5.6 Conclusion

In this analysis, all control measures for Kilns 1 and 2 were found to be either economically infeasible or infeasible due to secondary concerns (e.g., kiln operational issues, product quality, fuel supply uncertainty, increase in PM_{10}, NO_X, and metal HAPs emissions, etc.) at the Facility. Also, for Kilns 3 and 4, control measures were found to be either economically infeasible or infeasible due to secondary concerns (e.g., kiln operational issues, product quality, fuel supply uncertainty, increase in PM_{10}, NO_X, and metal HAPs emissions, etc.) at the Facility, with the exception of increased natural gas usage for Kilns 3 and 4 up to 20%. While emissions reductions for some sources through implementation of wet FGD scrubbers may seem cost effective (Kilns 3 and 4), the high costs associated with implementation of these emissions controls, secondary impacts to solid waste and wastewater generation (including potential influences to facility water discharges), lack of direct evidence of significant visibility improvement at the Sipsey Wilderness Area due to these emissions reductions, and the fact that there is no need for any emissions reductions from this source to meet reasonable progress for the Sipsey Wilderness Area at this time, Lhoist does not consider addition of controls at the facility feasible for visibility improvements at the Sipsey Wilderness Area as part of this implementation period.

APPENDIX A. EMISSIONS AND COSTING CALCULATIONS

Table 1. Economic Analysis - Alternative Fuel Scenarios - General Assumptions

Parameters	Value	Unit
Coal Sulfur Content[1]	1.47	%
Coke Sulfur Content[1]	5.25	%
Natural Gas Sulfur Content[2]	2.80E-04	lb S/MMBtu
Coal HHV[1]	26.85	MMBtu/ton
Coke HHV[1]	29.12	MMBtu/ton
Natural Gas HHV[2]	1,020	MMBtu/MMscf
Cost of Coal[3]	3.33	$/MMBtu
Cost of Coke[3]	2.21	$/MMBtu
Cost of Natural Gas[3]	4.16	$/MMBtu
Kilns 1 and 2 Percent of Input Sulfur in LKD/LKS[4]	5.93	%
Kilns 1 and 2 Percent of Input Sulfur in Lime[5]	2.60	%
Kilns 3 and 4 Percent of Input Sulfur in LKD/LKS[4]	13.31	%
Kilns 3 and 4 Percent of Input Sulfur in Lime[5]	7.33	%
SO_2 to S Molar Mass Ratio	2	
Low Sulfur Coal Sulfur Content[6]	0.83	%
Low Sulfur Coal HHV[6]	25.89	MMBtu/ton
Cost of Low Sulfur Coal[3]	3.82	$/MMBtu

1. From as received fuel sampling data.
2. Based on AP-42 Section 1.4.
3. Based on quoted fuel costs.
4. Based on Lhoist estimate for the percent of input sulfur that exits in the kiln in lime kiln dust (LKD) or lime kiln suldge (LKS) from 2018 & 2019 data.
5. Based on Lhoist estimate for the percent of input sulfur that exits in the kiln in lime from customer product specifications.
6. From sampling data on Appalachian coal.

Table 2. Economic Analysis - Alternative Fuel Scenarios - Kiln Specific Assumptions[1]

Parameters	Value	Unit
Kiln 1 Fuel Efficiency[1]	10.6	MMBtu/ton production
Kiln 2 Fuel Efficiency[1]	12.0	MMBtu/ton production
Kiln 3 Fuel Efficiency[1]	7.2	MMBtu/ton production
Kiln 4 Fuel Efficiency[1]	7.6	MMBtu/ton production
Input Sulfur Removed by the Kiln 1 Venturi Scrubber[2]	75	%
Input Sulfur Removed by the Kiln 2 Venturi Scrubber[2]	75	%
Heat Input Required for Kiln 1[3]	956,700	MMBtu/yr
Heat Input Required for Kiln 2[3]	910,100	MMBtu/yr
Heat Input Required for Kiln 3[3]	1,440,000	MMBtu/yr
Heat Input Required for Kiln 4[3]	1,518,000	MMBtu/yr

1. Kiln specific parameters and assumptions based on Lhoist estimates for 2018 & 2019
2. Lhoist estimate based on percent of input sulfur removed by the scrubber.
3. Based on review of facility data from 2015-2019

Table 3. Economic Analysis - Alternative Fuel Scenarios - Baseline - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	36.4%	35.6%	38.4%	38.4%
Coke	54.6%	53.4%	57.6%	57.6%
Natural Gas	9.0%	11.0%	4.0%	4.0%

1. Fuel mix based on Lhoist estimates for 2019.

Table 4. Economic Analysis - Alternative Fuel Scenarios - Baseline

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	$ -	$ -	$ -	$ -	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ 1,160,882	$ 1,080,066	$ 1,843,337	$ 1,943,185	$ 6,027,470
Coke	$ 1,153,701	$ 1,073,384	$ 1,831,934	$ 1,931,164	$ 5,990,183
Natural Gas	$ 358,085	$ 416,341	$ 239,546	$ 252,522	$ 1,266,494
Total Annualized Cost[4]	$ 2,672,668	$ 2,569,791	$ 3,914,818	$ 4,126,870	$ 13,284,147

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 5. Economic Analysis - Alternative Fuel Scenarios - Baseline - SO_2 Emissions with Add-On Controls

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	62.8	58.4	481	507	1,108
Coke (tpy)[1]	310	288.6	2,373	2,502	5,474
Natural Gas (tpy)[2]	3.97E-03	4.62E-03	1.28E-02	1.35E-02	3.49E-02
Total	373	347	2,854	3,008	6,582

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Table 6. Economic Analysis - Alternative Fuel Scenarios - Max Coal - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	91.0%	91.0%	95.0%	95.0%
Coke	0.0%	0.0%	0.0%	0.0%
Natural Gas	9.0%	9.0%	5.0%	5.0%

1. Fuel mix based on Lhoist estimates for maximum coal usage. Excluding natural gas, this is equivalent to 100% coal.

Table 7. Economic Analysis - Alternative Fuel Scenarios - Max Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	$ -	$ -	$ -	$ -	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ 2,902,206	$ 2,760,842	$ 4,560,340	$ 4,807,358	$ 15,030,746
Coke	$ -	$ -	$ -	$ -	$ -
Natural Gas	$ 358,085	$ 340,643	$ 299,433	$ 315,652	$ 1,313,813
Downtime Revenue Loss[4]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[5]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Total Annualized Cost[6]	$ 4,234,151	$ 3,944,389	$ 6,911,773	$ 7,125,811	$ 16,344,559

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
5. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
6. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 8. Economic Analysis - Alternative Fuel Scenarios - Max Coal - SO_2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	157.0	149.4	1,189	1,253	2,748
Coke (tpy)[1]	0	0	0	0	0
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	1.60E-02	1.69E-02	4.06E-02
Total	157	149.4	1,189	1,253	2,749

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Table 9. Economic Analysis - Alternative Fuel Scenarios - Max Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-216	-198	-1,665	-1,755	-3,834
Total Annualized Cost Difference	$ 1,561,483	$ 1,374,598	$ 2,996,955	$ 2,998,940	$ 8,931,976
Cost Effectiveness ($/ton reduced)	$ 7,229	$ 6,953	$ 1,800	$ 1,709	$ 2,330

Table 10. Economic Analysis - Alternative Fuel Scenarios - Increased Coal - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	72.8%	72.8%	76.0%	76.0%
Coke	18.2%	18.2%	19.0%	19.0%
Natural Gas	9.0%	9.0%	5.0%	5.0%

1. Fuel mix based on Lhoist estimates for increased coal usage and reduced coke usage. Excluding natural gas, this is roughly equivalent to 80% coal and 20% coke.

Table 11. Economic Analysis - Alternative Fuel Scenarios - Increased Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	$ -	$ -	$ -	$ -	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ 2,321,765	$ 2,208,674	$ 3,648,272	$ 3,845,886	$ 12,024,597
Coke	$ 384,567	$ 365,835	$ 604,284	$ 637,016	$ 1,991,702
Natural Gas	$ 358,085	$ 340,643	$ 299,433	$ 315,652	$ 1,313,813
Downtime Revenue Loss[4]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[5]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Total Annualized Cost[6]	$ 4,038,277	$ 3,758,056	$ 6,603,989	$ 6,801,355	$ 15,330,111

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
5. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
6. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 12. Economic Analysis - Alternative Fuel Scenarios - Increased Coal - SO_2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	125.6	119.5	951	1,003	2,199
Coke (tpy)[1]	103	98.4	783	825	1,810
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	1.60E-02	1.69E-02	4.06E-02
Total	229	217.9	1,734	1,828	4,009

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Table 13. Economic Analysis - Alternative Fuel Scenarios - Increased Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-144	-129	-1,120	-1,181	-2,574
Total Annualized Cost Difference	$ 1,365,608	$ 1,188,265	$ 2,689,171	$ 2,674,484	$ 7,917,528
Cost Effectiveness ($/ton reduced)	$ 9,483	$ 9,198	$ 2,401	$ 2,265	$ 3,076

Table 14. Economic Analysis - Alternative Fuel Scenarios - Increased Natural Gas - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	28.0%	28.0%	28.0%	28.0%
Coke	52.0%	52.0%	52.0%	52.0%
Natural Gas	20.0%	20.0%	20.0%	20.0%

1. Fuel mix based on Lhoist estimates for increased natural gas usage.

Table 15. Economic Analysis - Alternative Fuel Scenarios - Increased Natural Gas

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	$ -	$ -	$ -	$ -	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ 892,987	$ 849,490	$ 1,344,100	$ 1,416,906	$ 4,503,482
Coke	$ 1,098,763	$ 1,045,243	$ 1,653,829	$ 1,743,412	$ 5,541,247
Natural Gas	$ 795,744	$ 756,984	$ 1,197,732	$ 1,262,610	$ 4,013,069
Total Annualized Cost[4]	$ 2,787,493	$ 2,651,717	$ 4,195,662	$ 4,422,927	$ 14,057,798

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 16. Economic Analysis - Alternative Fuel Scenarios - Increased Natural Gas - SO_2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	48.3	46.0	350	369	814
Coke (tpy)[1]	295	281.1	2,143	2,259	4,978
Natural Gas (tpy)[2]	8.83E-03	8.40E-03	6.40E-02	6.75E-02	1.49E-01
Total	344	327.0	2,493	2,628	5,792

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Table 17. Economic Analysis - Alternative Fuel Scenarios - Increased Natural Gas - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-29	-20	-361	-380	-791
Total Annualized Cost Difference	$ 114,825	$ 81,926	$ 280,844	$ 296,056	$ 773,651
Cost Effectiveness ($/ton reduced)	$ 3,924	$ 4,088	$ 778	$ 778	$ 979

Table 18. Economic Analysis - Alternative Fuel Scenarios - Max Low Sulfur Coal - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Low Sulfur Coal	91.0%	91.0%	95.0%	95.0%
Coke	0.0%	0.0%	0.0%	0.0%
Natural Gas	9.0%	9.0%	5.0%	5.0%

1. Fuel mix based on Lhoist estimates for maximum low sulfur coal usage. Excluding natural gas, this is equivalent to 100% low sulfur coal.

Table 19. Economic Analysis - Alternative Fuel Scenarios - Max Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	$ -	$ -	$ -	$ -	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Low Sulfur Coal	$ 3,322,325	$ 3,160,497	$ 5,220,487	$ 5,503,263	$ 17,206,571
Coke	$ -	$ -	$ -	$ -	$ -
Natural Gas	$ 358,085	$ 340,643	$ 299,433	$ 315,652	$ 1,313,813
Downtime Revenue Loss[4]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[5]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Total Annualized Cost[6]	$ 4,654,269	$ 4,344,044	$ 7,571,920	$ 7,821,715	$ 18,520,384

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
5. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
6. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 20. Economic Analysis - Alternative Fuel Scenarios - Max Low Sulfur Coal - SO_2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Low Sulfur Coal (tpy)[1]	91.9	87.5	696	734	1,609
Coke (tpy)[1]	0	0.0	0	0	0
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	1.60E-02	1.69E-02	4.06E-02
Total	92	87.5	696	734	1,609

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Table 21. Economic Analysis - Alternative Fuel Scenarios - Max Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-281	-260	-2,158	-2,275	-4,973
Total Annualized Cost Difference	$ 1,981,601	$ 1,774,253	$ 3,657,102	$ 3,694,845	$ 11,107,801
Cost Effectiveness ($/ton reduced)	$ 7,050	$ 6,834	$ 1,695	$ 1,624	$ 2,234

Table 22. Economic Analysis - Alternative Control Technologies - Assumptions

Parameters	Value	Unit
Hydrated Lime Cost[1]	150	$/ton
Wet FGD Scrubber Reagent Cost[1]	150	$/ton
Hydrated Lime Injection Control Efficiency (with baghouse)[1]	50	%
Producer Price Index Adjustment[2]	1.078	2019$/2016$
Producer Price Index Adjustment[2]	1.524	2019$/2002$
Producer Price Index Adjustment[2]	1.489	2019$/2001$
Wet FGD Scrubber Control Efficiency[3]	98	%
Kiln 1 Potential Heat Input of Coal and Coke[4]	109	MMBtu/hr
Kiln 2 Potential Heat Input of Coal and Coke[4]	104	MMBtu/hr
Kiln 3 Potential Heat Input of Coal and Coke[4]	164	MMBtu/hr
Kiln 4 Potential Heat Input of Coal and Coke[4]	173	MMBtu/hr
Kiln 1 Exhaust Flow Rate[5]	40,015	dscfm
Kiln 2 Exhaust Flow Rate[5]	37,340	dscfm
Kiln 3 Exhaust Flow Rate[5]	82,529	dscfm
Kiln 4 Exhaust Flow Rate[5]	78,702	dscfm

1. Based on April 2017 Final Report, *Dry Sorbent Injection for SO$_2$/HCl Control Cost Development Methodology*, by Sargent & Lundy, LLC, funded by the U.S. EPA. Control efficiency based on percent of input sulfur removed by the hydrated lime. https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-5_dsi_cost_development_methodology.pdf

The 50% control efficiency estimate from the Sargent & Lundy report is consistent with Lhoist's experience with DSI. Based on DSI testing conducted with Sorbacal® SPS in June 2013 at Lhoist's Nelson, AZ Facility, control efficiency was estimated to be 40%. A vendor previously contacted by Lhoist could only guarantee reduction up to 50%. Based on these factors Lhoist considers the 50% control efficiency used here to be representative of different sorbents such as hydrated lime, Sorbacal®, and trona.

The control efficiency is converted to the effective amount of input sulfur removed based on existing inherent controls to be used in calculations.

2. Based on PPI data from the St. Louis Fed. https://fred.stlouisfed.org/series/PPIACO#0

3. From the Air Pollution Control Technology Fact Sheet for Flue Gas Desulfurization (2003). Using the highest value in the given range (90% to 98%) for control efficiency. The control efficiency is converted to the effective amount of input sulfur removed based on existing inherent controls to be used in calculations.

4. Based on review of facility data from 2015-2019

5. Based on 2019 & 2018 Annual PM Compliance Stack Testing

Table 23. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Hydrate Injection - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	36.4%	35.6%	38.4%	38.4%
Coke	54.6%	53.4%	57.6%	57.6%
Natural Gas	9.0%	11.0%	4.0%	4.0%

1. Baseline fuel mix.

Table 24. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Hydrate Injection

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
Injection System[1]					
Base Module Cost	$ -	$ -	$ 8,082,524	$ 8,082,524	$ 16,165,049
Other Project Costs	$ -	$ -	$ 1,616,505	$ 1,616,505	$ 3,233,010
Owners Costs	$ -	$ -	$ 80,825	$ 80,825	$ 161,650
Baghouse[2]					
Capital Cost	$ -	$ -	$ 2,012,423	$ 1,919,104	$ 3,931,528
Total Capital Investment[3]	$ -	$ -	$ 11,792,278	$ 11,698,959	$ 23,491,236
Capital Recovery Factor[4]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[5]	$ -	$ -	$ 1,113,108	$ 1,104,299	$ 2,217,407
Annual Costs					
Injection System[1]					
Additional Labor Costs	$ -	$ -	$ 249,600	$ 249,600	$ 499,200
Additional Maintenance Costs	$ -	$ -	$ 80,825	$ 80,825	$ 161,650
Hydrated Lime Costs	$ -	$ -	$ 1,314,000	$ 1,314,000	$ 2,628,000
Waste Disposal Costs	$ -	$ -	$ 1,189,520	$ 1,189,520	$ 2,379,040
Additional Power Costs	$ -	$ -	$ 94,608	$ 94,608	$ 189,216
Baghouse[2]					
O&M Costs	$ -	$ -	$ 628,882	$ 599,720	$ 1,228,602
Indirect Annual Costs[6]					
Overhead	$ -	$ -	$ 1,363,985	$ 1,346,487	$ 2,710,472
Administrative Charges	$ -	$ -	$ 235,846	$ 233,979	$ 469,825
Property Tax	$ -	$ -	$ 117,923	$ 116,990	$ 234,912
Insurance	$ -	$ -	$ 117,923	$ 116,990	$ 234,912
Total Annualized Cost[7]	$ -	$ -	$ 6,506,219	$ 6,447,018	$ 12,953,237

1. Based on April 2017 Final Report, *Dry Sorbent Injection for SO $_2$/HCl Control Cost Development Methodology*, by Sargent & Lundy, LLC, funded by the U.S. EPA. Assumes 1 tph hydrate injection rate and retrofit factor of 1 (per kiln). Cost includes all equipment from unloading to injection, including dehumidification system. Converted from 2016 dollars to 2019 dollars.
https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-5_dsi_cost_development_methodology.pdf

2. Based on the Air Pollution Control Technology Fact Sheet for Pulse-Jet Cleaned Type Fabric Filters (2003). For capital cost, using average costs in terms of $/scfm due to higher temperature tolerance required. For O&M costs, using minimum costs in terms of $/scfm to be conservative. Converted from 2002 dollars to 2019 dollars.
https://nepis.epa.gov/Exe/ZyPDF.cgi/P100RQ6L.PDF?Dockey=P100RQ6L.PDF

3. Total Capital Investment is equal to the sum of all capital costs.

4. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.

5. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor

6. Indirect Annual Costs based on EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.4.

7. Fuel costs are equivalent to baseline fuel costs and are not listed.
Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 25. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Hydrate Injection - SO$_2$ Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	62.8	58.4	240	253	615
Coke (tpy)[1]	310	288.6	1,187	1,251	3,036
Natural Gas (tpy)[2]	3.97E-03	4.62E-03	6.40E-03	6.75E-03	2.17E-02
Total	373	347.1	1,427	1,504	3,651

1. Baseline SO$_2$ Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD (%) - Input Sulfur in Lime (%) - {Input Sulfur Removed by Scrubber (%) OR Input Sulfur Removed by Hydrate Injection (%)}]
2. Baseline SO$_2$ Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton)* Molar Mass Ratio *
[100% - Input Sulfur in LKD (%) - Input Sulfur in Lime (%) - {Input Sulfur Removed by Scrubber (%) OR Input Sulfur Removed by Hydrate Injection (%)}]

Table 26. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Hydrate Injection - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO$_2$ Emissions Difference (tpy)	0	0	-1,427	-1,504	-2,931
Total Annualized Cost Difference	$ -	$ -	$ 6,506,219	$ 6,447,018	$ 12,953,237
Cost Effectiveness ($/ton reduced)	N/A	N/A	$ 4,560	$ 4,286	$ 4,419

Table 27. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Wet FGD Scrubber - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	36.4%	35.6%	38.4%	38.4%
Coke	54.6%	53.4%	57.6%	57.6%
Natural Gas	9.0%	11.0%	4.0%	4.0%

1. Baseline fuel mix.

Table 28. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Wet FGD Scrubber

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
Scrubber Capital Cost[1]	$ -	$ -	$ 6,118,449	$ 6,449,865	$ 12,568,315
Pond Expansion Cost[2]	$ -	$ -	$ 1,000,000	$ 1,000,000	$ 2,000,000
Total Capital Investment[3]	$ -	$ -	$ 7,118,449	$ 7,449,865	$ 14,568,315
Capital Recovery Factor[4]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[5]	$ -	$ -	$ 671,931	$ 703,215	$ 1,375,146
Annual Costs					
Direct Annual Costs					$ -
O&M Costs[1]	$ -	$ -	$ 318,159	$ 335,393	$ 653,552
Reagent Costs[6]	$ -	$ -	$ 1,314,000	$ 1,314,000	$ 2,628,000
Waste Disposal Costs[6]	$ -	$ -	$ 1,189,520	$ 1,189,520	$ 2,379,040
Indirect Annual Costs[7]					
Overhead	$ -	$ -	$ 979,296	$ 989,636	$ 1,968,931
Administrative Charges	$ -	$ -	$ 142,369	$ 148,997	$ 291,366
Property Tax	$ -	$ -	$ 71,184	$ 74,499	$ 145,683
Insurance	$ -	$ -	$ 71,184	$ 74,499	$ 145,683
Downtime Revenue Loss[8]	$ -	$ -	$ 1,537,344	$ 1,502,720	$ 3,040,064
Kiln Startup[9]	$ -	$ -	$ 178,500	$ 140,250	$ 318,750
Total Annualized Cost[10]	$ -	$ -	$ 6,473,488	$ 6,472,728	$ 12,946,216

1. Based on the Air Pollution Control Technology Fact Sheet for Flue Gas Desulfurization (2003). For capital cost, using minimum costs in terms of $/MMBtu/hr for Wet FGD Scrubbers with unit size < 4,000 MMBtu/hr to be conservative. For O&M costs, using average costs in terms of $/MMBtu/hr for Wet FGD Scrubbers with unit size < 4,000 MMBtu/hr to be more representative. Converted from 2001 dollars to 2019 dollars.
https://www.epa.gov/sites/production/files/2020-08/documents/ffdg.pdf

2. Lhoist estimate for expansion of the water pond (required for scrubber water).

3. Total Capital Investment is equal to the sum of all capital costs.

4. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.

5. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor

6. Reagent and waste disposal costs assumed to be similar to hydrated lime based on April 2017 Final Report, Dry Sorbent Injection for SO2/HCl Control Cost Development Methodology, by Sargent & Lundy, LLC, funded by the U.S. EPA. Assumes 1 tph reagent usage rate.

7. Indirect Annual Costs based on EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.4.

8. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.

9. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.

10. Fuel costs are equivalent to baseline fuel costs and are not listed.
Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 29. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Wet FGD Scrubber - SO₂ Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	62.8	58.4	10	10	141
Coke (tpy)[1]	310	288.6	47	50	696
Natural Gas (tpy)[2]	3.97E-03	4.62E-03	2.56E-04	2.70E-04	9.12E-03
Total	373	347.1	57	60	837

1. Baseline SO2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio * [100% - Input Sulfur in LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber (%)]

2. Baseline SO2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton)* Molar Mass Ratio * [100% - Input Sulfur in LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber (%)]

Table 30. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Wet FGD Scrubber - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO₂ Emissions Difference (tpy)	0	0	-2,797	-2,948	-5,745
Total Annualized Cost Difference	$ -	$ -	$ 6,473,488	$ 6,472,728	$ 12,946,216
Cost Effectiveness ($/ton reduced)	N/A	N/A	$ 2,315	$ 2,195	$ 2,253

Table 31. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Hydrate Injection - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	36.4%	35.6%	38.4%	38.4%
Coke	54.6%	53.4%	57.6%	57.6%
Natural Gas	9.0%	11.0%	4.0%	4.0%

1. Baseline fuel mix.

Table 32. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Hydrate Injection

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
Injection System[1]					
Base Module Cost	$ 8,082,524	$ 8,082,524	$ -	$ -	$ 16,165,049
Other Project Costs	$ 1,616,505	$ 1,616,505	$ -	$ -	$ 3,233,010
Owners Costs	$ 80,825	$ 80,825	$ -	$ -	$ 161,650
Baghouse[2]					
Capital Cost	$ 975,731	$ 910,503	$ -	$ -	$ 1,886,234
Total Capital Investment[3]	$ 10,755,586	$ 10,690,357	$ -	$ -	$ 21,445,943
Capital Recovery Factor[4]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[5]	$ 1,015,251	$ 1,009,094	$ -	$ -	$ 2,024,345
Annual Costs					
Injection System[1]					
Additional Labor Costs	$ 249,600	$ 249,600	$ -	$ -	$ 499,200
Additional Maintenance Costs	$ 80,825	$ 80,825	$ -	$ -	$ 161,650
Hydrated Lime Costs	$ 1,314,000	$ 1,314,000	$ -	$ -	$ 2,628,000
Waste Disposal Costs	$ 1,189,520	$ 1,189,520	$ -	$ -	$ 2,379,040
Additional Power Costs	$ 94,608	$ 94,608	$ -	$ -	$ 189,216
Baghouse[2]					
O&M Costs	$ 304,916	$ 284,532	$ -	$ -	$ 589,448
Indirect Annual Costs[6]					
Overhead	$ 1,169,605	$ 1,157,374	$ -	$ -	$ 2,326,979
Administrative Charges	$ 215,112	$ 213,807	$ -	$ -	$ 428,919
Property Tax	$ 107,556	$ 106,904	$ -	$ -	$ 214,459
Insurance	$ 107,556	$ 106,904	$ -	$ -	$ 214,459
Total Annualized Cost[7]	$ 5,848,549	$ 5,807,168	$ -	$ -	$ 11,655,717

1. Based on April 2017 Final Report, *Dry Sorbent Injection for SO$_2$/HCl Control Cost Development Methodology*, by Sargent & Lundy, LLC, funded by the U.S. EPA. Assumes 1 tph hydrate injection rate and retrofit factor of 1 (per kiln). Cost includes all equipment from unloading to injection, including dehumidification system. Converted from 2016 dollars to 2019 dollars.
https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-5_dsi_cost_development_methodology.pdf

2. Based on the Air Pollution Control Technology Fact Sheet for Pulse-Jet Cleaned Type Fabric Filters (2003). For capital cost, using average costs in terms of $/scfm due to higher temperature tolerance required. For O&M costs, using minimum costs in terms of $/scfm to be conservative. Converted from 2002 dollars to 2019 dollars.
https://nepis.epa.gov/Exe/ZyPDF.cgi/P100RQ6L.PDF?Dockey=P100RQ6L.PDF

3. Total Capital Investment is equal to the sum of all capital costs.

4. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.

5. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor

6. Indirect Annual Costs based on EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.4.

7. Fuel costs are equivalent to baseline fuel costs and are not listed.
Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 33. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Hydrate Injection - SO$_2$ Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	174.4	162.3	481	507	1,324
Coke (tpy)[1]	861	801.4	2,373	2,502	6,538
Natural Gas (tpy)[2]	1.10E-02	1.28E-02	1.28E-02	1.35E-02	5.02E-02
Total	1036	963.7	2,854	3,008	7,862

1. Baseline SO2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Hydrate Injection (%) {Kilns 1 & 2 only}]
2. Baseline SO2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton)* Molar Mass Ratio *
[100% - Input Sulfur in LKD (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Hydrate Injection (%) {Kilns 1 & 2 only}]

Table 34. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Hydrate Injection - Incremental Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO$_2$ Emissions Difference (tpy)[1]	+663	+617	0	0	+1,279
Total Annualized Cost Difference	$ 5,848,549	$ 5,807,168	$ -	$ -	$ 11,655,717
Cost Effectiveness ($/ton reduced)	N/A	N/A	N/A	N/A	N/A

1. Compared to baseline SO$_2$ Emissions with Add-On Controls (Table 5).

Table 35. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Wet FGD Scrubber - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	36.4%	35.6%	38.4%	38.4%
Coke	54.6%	53.4%	57.6%	57.6%
Natural Gas	9.0%	11.0%	4.0%	4.0%

1. Baseline fuel mix.

Table 36. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Wet FGD Scrubber

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
Scubber Capital Cost[1]	$ 4,064,945	$ 3,866,945	$ -	$ -	$ 7,931,890
Pond Expansion Cost[2]	$ 1,000,000	$ 1,000,000	$ -	$ -	$ 2,000,000
Total Capital Investment[3]	$ 4,064,945	$ 3,866,945	$ -	$ -	$ 7,931,890
Capital Recovery Factor[4]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[5]	$ 383,702	$ 365,012	$ -	$ -	$ 748,714
Annual Costs					
Direct Annual Costs					$ -
O&M Costs[1]	$ 211,377	$ 201,081	$ -	$ -	$ 412,458
Reagent Costs[6]	$ 1,314,000	$ 1,314,000	$ -	$ -	$ 2,628,000
Waste Disposal Costs[6]	$ 1,189,520	$ 1,189,520	$ -	$ -	$ 2,379,040
Indirect Annual Costs[7]					
Overhead	$ 915,226	$ 909,049	$ -	$ -	$ 1,824,275
Administrative Charges	$ 81,299	$ 77,339	$ -	$ -	$ 158,638
Property Tax	$ 40,649	$ 38,669	$ -	$ -	$ 79,319
Insurance	$ 40,649	$ 38,669	$ -	$ -	$ 79,319
Downtime Revenue Loss[8]	$ 676,224	$ 571,034	$ -	$ -	$ 1,247,258
Kiln Startup[9]	$ 140,250	$ 140,250	$ -	$ -	$ 280,500
Total Annualized Cost[10]	$ 4,992,897	$ 4,844,624	$ -	$ -	$ 9,837,521

1. Based on the Air Pollution Control Technology Fact Sheet for Flue Gas Desulfurization (2003). For capital cost, using minimum costs in terms of $/MMBtu/hr for Wet FGD Scrubbers with unit size < 4,000 MMBtu/hr to be conservative.
For O&M costs, using average costs in terms of $/MMBtu/hr for Wet FGD Scrubbers with unit size < 4,000 MMBtu/hr to be more representative. Converted from 2001 dollars to 2019 dollars.
2. Lhoist estimate for expansion of the water pond (required for scrubber water).
3. Total Capital Investment is equal to the sum of all capital costs.
4. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
5. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
6. Reagent and waste disposal costs assumed to be similar to hydrated lime based on April 2017 Final Report, Dry Sorbent Injection for SO2/HCl Control Cost Development Methodology, by Sargent & Lundy, LLC, funded by the U.S. EPA. Assumes 1 tph reagent usage rate.
7. Indirect Annual Costs based on EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.4.
8. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
9. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
10. Fuel costs are equivalent to baseline fuel costs and are not listed.
Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 37. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Wet FGD Scrubber - SO₂ Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	7.0	6.5	481	507	1,001
Coke (tpy)[1]	34	32.1	2,373	2,502	4,942
Natural Gas (tpy)[2]	4.41E-04	5.13E-04	1.28E-02	1.35E-02	2.73E-02
Total	41	38.5	2,854	3,008	5,942

1. Baseline SO2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber (%) {Kilns 1 & 2 only}]
2. Baseline SO2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton)* Molar Mass Ratio *
[100% - Input Sulfur in LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber (%) {Kilns 1 & 2 only}]

Table 38. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Wet FGD Scrubber - Incremental Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO₂ Emissions Difference (tpy)[1]	-332	-309	0	0	-640
Total Annualized Cost Difference	$ 4,992,897	$ 4,844,624	$ -	$ -	$ 9,837,521
Cost Effectiveness ($/ton reduced)	$ 15,056	$ 15,702	N/A	N/A	$ 15,368

1. Compared to baseline SO₂ Emissions with Add-On Controls (Table 5).

APPENDIX B. VISTAS REGIONAL HAZE PROJECT UPDATE
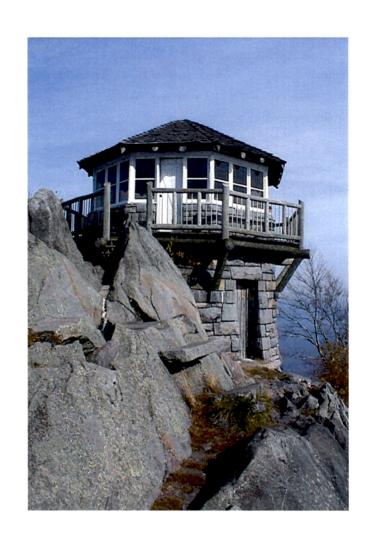
VISTAS Regional Haze Project Update

Stakeholder Briefing
Jim Boylan
May 20, 2020

Outline

- Background Information
- 2028 Emissions Updates
- 2028 Model Projections
- Adjusted 2028 PSAT Stacked Bar Charts
- Reasonable Progress Screening Analysis
- Next Steps & Schedule
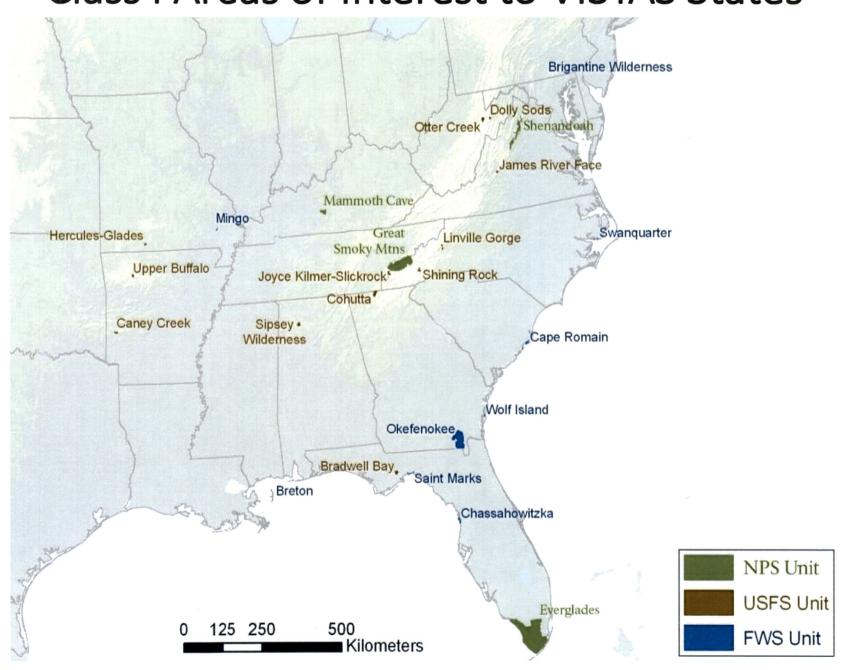
Regional Haze Background Information

- Initial round of regional haze SIPs were due December 17, 2007
- Regional haze SIPs for second planning period due July 31, 2021
- EPA revised regional haze regulations
  - 40 CFR Part 51 and 40 CFR Part 52
  - Revisions effective January 10, 2017
- Current EPA regional haze guidance
  - December 20, 2018 – Tracking Visibility Progress
  - August 20, 2019 – Regional Haze SIPs for the Second Planning Period

VISTAS Organization

- ## State and Tribal Air Directors (STAD)
  - Policy Decisions
  - Michelle Walker Owenby (TN), Chair

- ## Coordinating Committee (CC)
  - Planning Recommendations
  - Jim Boylan (GA), Chair

- ## Technical Analysis Work Group (TAWG)
  - Technical Recommendations
  - Randy Strait (NC), Chair

- ## Project Manager
  - John Hornback (SESARM)

4

Class I Areas of Interest to VISTAS States

VISTAS Class I Areas
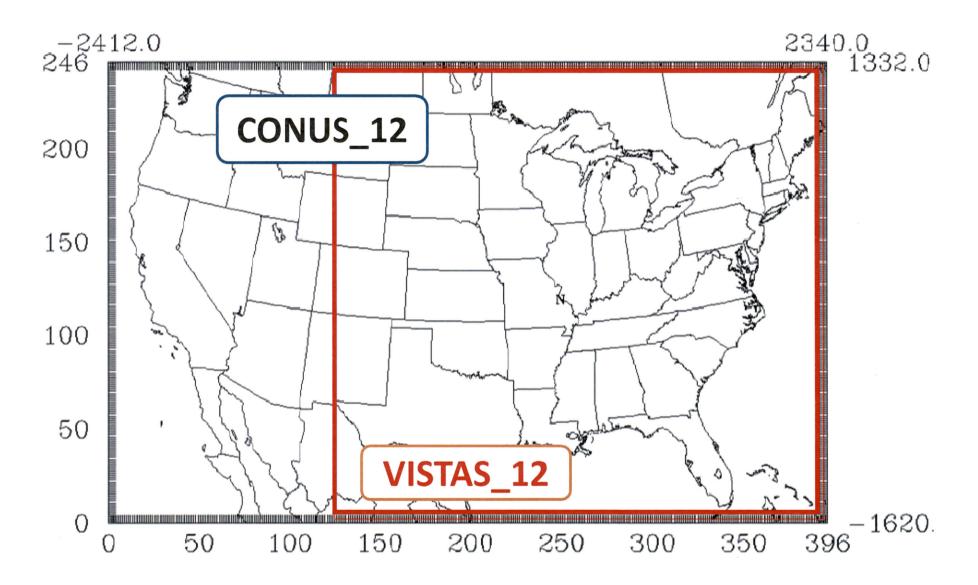
VISTAS FEDERAL CLASS I AREAS	
AL – Sipsey Wilderness Area (SIPS)	USDA Forest Service
FL – Chassahowitzka Wilderness Area (CHAS)	USDI Fish and Wildlife Service
FL – Everglades National Park (EVER)	USDI National Park Service
FL – Saint Marks Wilderness Area (SAMA)	USDI Fish and Wildlife Service
GA – Cohutta Wilderness Area (COHU)	USDA Forest Service
GA – Okefenokee Wilderness Area (OKEF)	USDI Fish and Wildlife Service
GA – Wolf Island Wilderness Area (WOLF)*	USDI Fish and Wildlife Service
KY – Mammoth Cave National Park (MACA)	USDI National Park Service
NC – Linville Gorge Wilderness Area (LIGO)	USDA Forest Service
NC – Shining Rock Wilderness Area (SHRO)	USDA Forest Service
NC – Swanquarter Wilderness Area (SWAN)	USDI Fish and Wildlife Service
SC – Cape Romain Wilderness Area (ROMA)	USDI Fish and Wildlife Service
TN/NC – Great Smoky Mountains National Park (GRSM)	USDI National Park Service
TN/NC – Joyce Kilmer-Slickrock Wilderness Area (JOYC)*	USDA Forest Service
VA – James River Face Wilderness Area (JARI)	USDA Forest Service
VA – Shenandoah National Park (SHEN)	USDI National Park Service
WV – Dolly Sods Wilderness Area (DOSO)	USDA Forest Service
WV – Otter Creek Wilderness Area (OTCR)*	USDA Forest Service

*This Class I Area does not have an IMPROVE monitor and will be represented by measurement data from a nearby Class I Area with an IMPROVE monitor.

VISTAS Air Quality Model
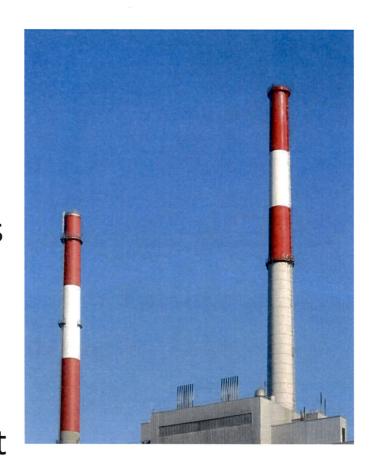
- Started with EPA's 2011/2028 modeling platform
  - Version 6.3el
  - CAMx v6.32
- Replaced CAMx v6.32 with CAMx v6.40
- Used 2011 meteorology
- Reasons for using EPA platform
  - Time limited
  - Budget limited
  - Most source sectors acceptably represented in EPA platform

VISTAS Modeling Domains

CONUS_12

VISTAS_12

Initial VISTAS Emissions Updates

- Used EPA's 2011 base year emissions without change
- Updated EPA's Initial 2028 projection year emissions
  - EGU and major non-EGU sources
  - Removed Clean Power Plan assumptions
  - VISTAS – Adjusted for changes in fuels and facility operating plans
  - Non-VISTAS – Used ERTAC 2.7opt

Initial VISTAS vs. Updated EPA 2028 Emissions

- The table below compares the 2028 point emissions used by VISTAS vs. the latest 2028fh emissions used by EPA (projected from 2016). The emissions below are extracted from the VISTAS 12 modeling domain which covers the Eastern U.S.

Pollutant	VISTAS 2028 (tpy)	New EPA 2028 (tpy)	Change (tpy)	Change (%)
NOx	2,641,463.83	2,108,115.50	**-533,348.33**	-20.19%
SO2	2,574,542.02	1,400,287.10	**-1,174,254.92**	-45.61%

Old ERTAC (2.7opt) vs. New ERTAC (16.0)

SO2	2.7opt_2028	16.0_2028	Δ SO2	Δ SO2
CENSARA	760,828.2	367,683.7	-393,144.5	**-51.67%**
LADCO	379,577.5	266,047.0	-113,530.5	**-29.91%**
MANE-VU	196,672.6	78,657.0	-118,015.6	**-60.01%**
VISTAS	273,582.1	161,502.5	-112,079.6	**-40.97%**
TOTAL	**1,783,376.5**	**976,471.2**	**-806,905.3**	**-45.25%**

NOx	2.7opt_2028	16.0_2028	Δ NOx	Δ NOx
CENSARA	354,795.1	244,499.3	-110,295.8	**-31.09%**
LADCO	198,966.9	166,429.4	-32,537.4	**-16.35%**
MANE-VU	83,432.5	56,315.3	-27,117.2	**-32.50%**
VISTAS	270,615.7	200,791.1	-69,824.6	**-25.80%**
TOTAL	**1,166,663.1**	**840,973.6**	**-325,689.5**	**-27.92%**

VISTAS CC/TAWG Conclusions (January 2020)

1. 2028 emission updates are necessary
   - **VISTAS States** – States will:
     - Update 2028 major source emissions projections (SO_2, NOx, $PM_{2.5}$, PM_{10}, NH_3, CO) at the facility and unit level
     - Add any new sources of significance
   - **LADCO States** – SESARM will:
     - Replace ERTAC_2.7 with ERTAC_16.1 based on LADCO input
   - **All Other States** – SESARM will:
     - Replace ERTAC_2.7 with ERTAC_16.0
     - Verify accuracy of large SO_2 and NOx source emissions projections via contact with surrounding states/RPOs and update emissions as needed

2. Additional 2028 air quality modeling is needed

Additional Modeling-Related Tasks

- Emissions processing
- Updated 2028 CAMx modeling (VISTAS_12)
- Updated 2028 visibility projections
- Documentation

Recent 2028 Emissions Updates

2028 EGU & NEGU SO$_2$ Comparison

State	Point_OLD (tpy)	Point_NEW (tpy)	Delta (%)	EGU_OLD (tpy)	EGU_NEW (tpy)	Delta (%)	NEGU_OLD (tpy)	NEGU_NEW (tpy)	Delta (%)
AL	87,111.28	59,056.98	-32.2%	15,480.96	8,365.96	-46.0%	71,630.32	50,691.02	-29.2%
FL	63,501.23	52,982.68	-16.6%	28,547.41	24,004.67	-15.9%	34,953.82	28,978.01	-17.1%
GA	37,065.83	36,166.09	-2.4%	18,473.28	17,573.54	-4.9%	18,592.55	18,592.55	0.0%
KY	75,140.26	65,636.83	-12.6%	56,262.06	49,585.95	-11.9%	18,878.20	16,050.88	-15.0%
MS	21,234.31	8,405.06	-60.4%	6,984.57	3,236.28	-53.7%	14,249.74	5,168.78	-63.7%
NC	35,232.88	24,347.18	-30.9%	19,734.80	9,571.47	-51.5%	15,498.08	14,775.71	-4.7%
SC	29,600.85	29,601.25	0.0%	10,693.79	10,695.34	0.0%	18,907.05	18,905.91	0.0%
TN	23,447.58	21,057.17	-10.2%	12,114.30	10,030.04	-17.2%	11,333.28	11,027.13	-2.7%
VA	19,839.18	18,551.32	-6.5%	3,264.09	1,976.23	-39.5%	16,575.09	16,575.09	0.0%
WV	63,404.07	53,715.79	-15.3%	57,828.67	47,744.49	-17.4%	5,575.41	5,971.30	7.1%
VISTAS	**455,577.46**	**369,520.35**	**-18.9%**	**229,383.91**	**182,783.96**	**-20.3%**	**226,193.55**	**186,736.39**	**-17.4%**
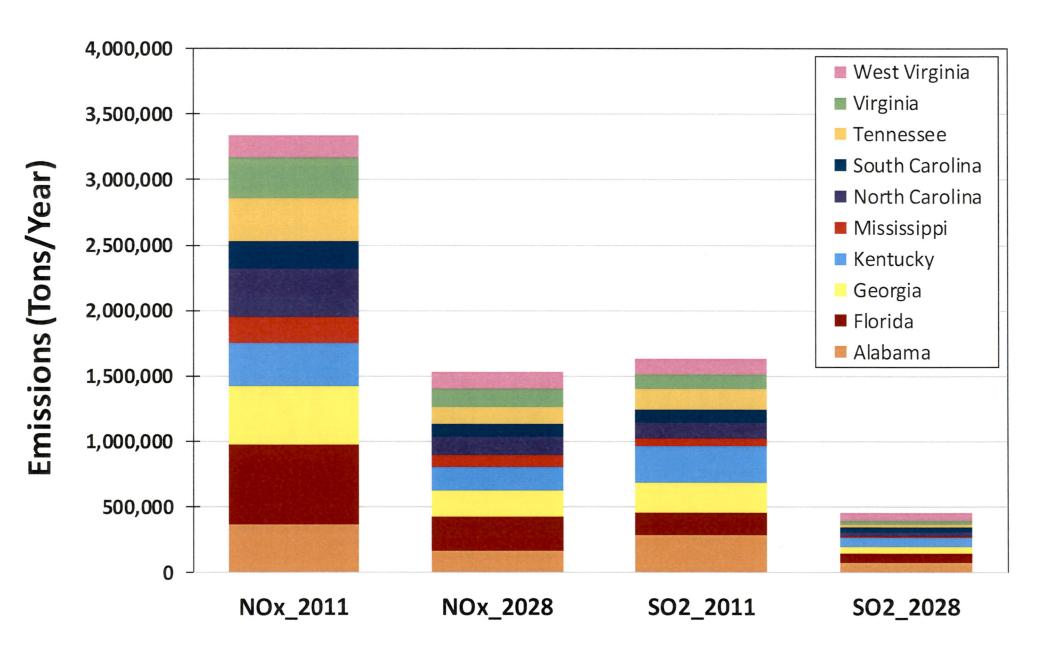
RPO	Point_OLD (tpy)	Point_NEW (tpy)	Delta (%)	EGU_OLD (tpy)	EGU_NEW (tpy)	Delta (%)	NEGU_OLD (tpy)	NEGU_NEW (tpy)	Delta (%)
VISTAS	455,577.46	369,520.35	-18.9%	229,383.91	182,783.96	-20.3%	226,193.55	186,736.39	-17.4%
CENSARA	1,012,946.59	621,321.29	-38.7%	773,625.13	382,000.54	-50.6%	239,321.46	239,320.75	0.0%
LADCO	660,186.42	498,171.62	-24.5%	444,506.99	282,492.18	-36.4%	215,679.44	215,679.44	0.0%
MANE-VU	270,810.83	149,439.76	-44.8%	203,661.43	95,074.20	-53.3%	67,149.39	54,365.55	-19.0%
WRAP	182,121.89	135,483.18	-25.6%	136,955.17	90,316.46	-34.1%	45,166.72	45,166.73	0.0%
TOTAL	**2,581,643.20**	**1,773,936.20**	**-31.3%**	**1,788,132.63**	**1,032,667.35**	**-42.2%**	**793,510.56**	**741,268.85**	**-6.6%**

2028 EGU & NEGU NOx Comparison

State	Point_OLD (tpy)	Point_NEW (tpy)	Delta (%)	EGU_OLD (tpy)	EGU_NEW (tpy)	Delta (%)	NEGU_OLD (tpy)	NEGU_NEW (tpy)	Delta (%)
AL	80,389.97	70,824.72	-11.9%	26,895.35	20,008.14	-25.6%	53,494.61	50,816.58	-5.0%
FL	68,006.19	70,010.40	2.9%	26,250.73	25,049.90	-4.6%	41,755.45	44,960.50	7.7%
GA	67,197.50	65,885.55	-2.0%	25,899.67	24,587.73	-5.1%	41,297.83	41,297.83	0.0%
KY	66,240.03	62,130.83	-6.2%	36,781.72	32,695.94	-11.1%	29,458.31	29,434.89	-0.1%
MS	52,159.32	46,853.62	-10.2%	18,279.53	12,208.89	-33.2%	33,879.79	34,644.73	2.3%
NC	65,863.97	58,933.80	-10.5%	27,842.23	20,977.65	-24.7%	38,021.74	37,956.15	-0.2%
SC	36,051.31	36,170.87	0.3%	10,522.78	10,707.42	1.8%	25,528.53	25,463.44	-0.3%
TN	45,879.07	42,954.25	-6.4%	10,086.01	7,814.13	-22.5%	35,793.06	35,140.12	-1.8%
VA	43,210.19	41,671.99	-3.6%	11,973.97	10,435.77	-12.8%	31,236.22	31,236.22	0.0%
WV	65,054.07	68,200.77	4.8%	46,721.77	49,874.15	6.7%	18,332.30	18,326.62	0.0%
VISTAS	**590,051.60**	**563,636.80**	**-4.5%**	**241,253.76**	**214,359.73**	**-11.1%**	**348,797.84**	**349,277.07**	**0.1%**
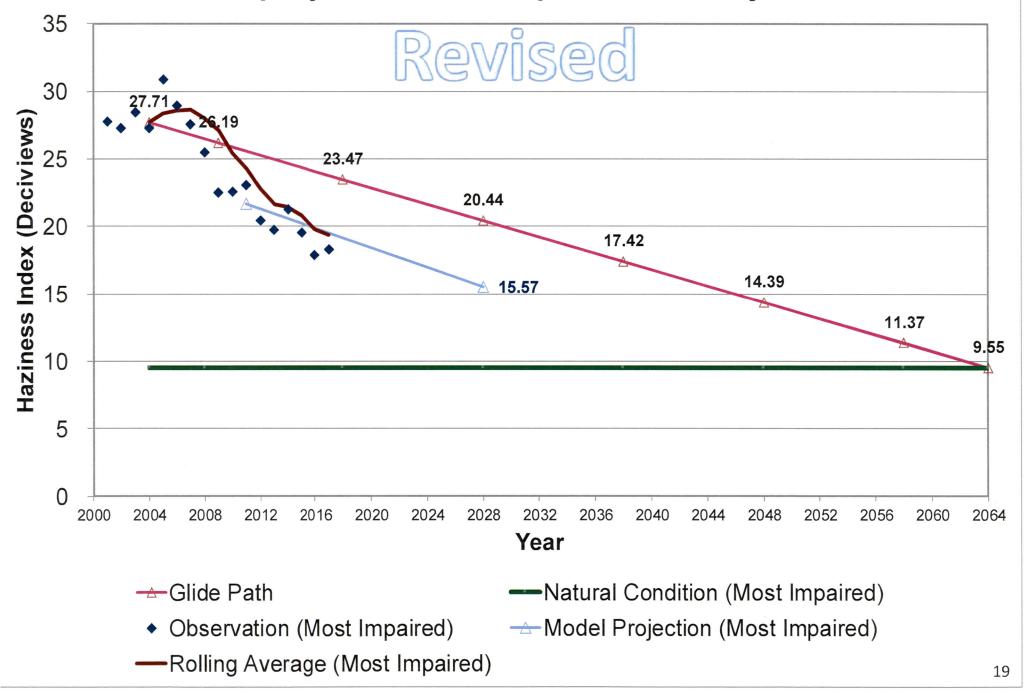
RPO	Point_OLD (tpy)	Point_NEW (tpy)	Delta (%)	EGU_OLD (tpy)	EGU_NEW (tpy)	Delta (%)	NEGU_OLD (tpy)	NEGU_NEW (tpy)	Delta (%)
VISTAS	590,051.60	563,636.80	-4.5%	241,253.76	214,359.73	-11.1%	348,797.84	349,277.07	0.1%
CENSARA	903,979.85	791,397.59	-12.5%	382,706.66	270,182.46	-29.4%	521,273.19	521,215.14	0.0%
LADCO	548,866.74	491,345.00	-10.5%	244,035.26	186,513.52	-23.6%	304,831.49	304,831.49	0.0%
MANE-VU	244,280.15	222,991.41	-8.7%	103,465.15	82,176.41	-20.6%	140,815.00	140,815.00	0.0%
WRAP	362,819.80	301,433.41	-16.9%	187,944.97	126,558.55	-32.7%	174,874.83	174,874.86	0.0%
TOTAL	**2,649,998.14**	**2,370,804.22**	**-10.5%**	**1,159,405.80**	**879,790.66**	**-24.1%**	**1,490,592.35**	**1,491,013.55**	**0.0%**

VISTAS States Emissions: 2011 vs. 2028
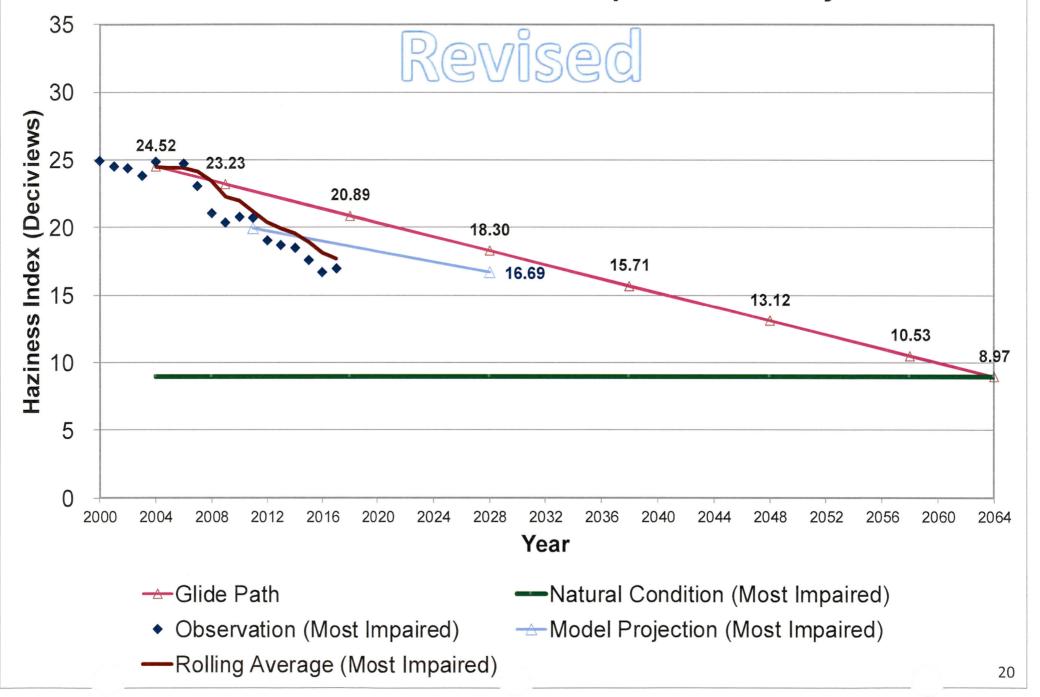
2028 Model Projections

**Uniform Rate of Progress Glide Path
Sipsey - 20% Most Impaired Data Days**

Revised

- Glide Path
- Observation (Most Impaired)
- Rolling Average (Most Impaired)
- Natural Condition (Most Impaired)
- Model Projection (Most Impaired)

27.71
26.19
23.47
20.44
17.42
14.39
11.37
9.55
15.57

19

Uniform Rate of Progress Glide Path
Chassahowitzka - 20% Most Impaired Data Days

Revised

Haziness Index (Deciviews) vs Year

24.52
23.23
20.89
18.30
16.69
15.71
13.12
10.53
8.97

Legend:
- Glide Path
- Natural Condition (Most Impaired)
- Observation (Most Impaired)
- Model Projection (Most Impaired)
- Rolling Average (Most Impaired)

20

Uniform Rate of Progress Glide Path
Everglades - 20% Most Impaired Data Days

Uniform Rate of Progress Glide Path
Saint Marks - 20% Most Impaired Data Days

Revised

Glide Path values: 24.60, 23.32, 21.00, 18.44, 15.87, 13.30, 10.73, 9.19

Model Projection: 16.05

Legend:
- Glide Path
- Natural Condition (Most Impaired)
- Observation (Most Impaired)
- Model Projection (Most Impaired)
- Rolling Average (Most Impaired)

22

Uniform Rate of Progress Glide Path Cohutta - 20% Most Impaired Data Days

Revised

Y-axis: Haziness Index (Deciviews), 0 to 35
X-axis: Year, 2000 to 2064

Data labels: 29.12, 27.49, 24.55, 21.28, 18.01, 14.75, 11.48, 9.52, 14.08

Legend:
— Glide Path
— Natural Condition (Most Impaired)
♦ Observation (Most Impaired)
— Model Projection (Most Impaired)
— Rolling Average (Most Impaired)

Uniform Rate of Progress Glide Path
Okefenokee - 20% Most Impaired Data Days

Uniform Rate of Progress Glide Path
Mammoth Cave - 20% Most Impaired Data Days

Revised

Glide Path values: 29.83, 28.16, 25.15, 21.81, 18.47, 15.13, 11.79, 9.79
Model Projection: 18.13

Legend:
- Glide Path
- Observation (Most Impaired)
- Rolling Average (Most Impaired)
- Natural Condition (Most Impaired)
- Model Projection (Most Impaired)

25

Uniform Rate of Progress Glide Path
Linville Gorge - 20% Most Impaired Data Days

Revised

Values labeled on the Glide Path: 28.05, 26.52, 23.77, 20.71, 17.65, 14.59, 11.53, 9.70

Model Projection value: 13.36

Haziness Index (Deciviews) — y-axis (0 to 35)
Year — x-axis (2000 to 2064)

Legend:
— Glide Path
— Natural Condition (Most Impaired)
♦ Observation (Most Impaired)
— Model Projection (Most Impaired)
— Rolling Average (Most Impaired)

26

Uniform Rate of Progress Glide Path
Shining Rock - 20% Most Impaired Data Days

Revised

Haziness Index (Deciviews) vs Year

Data labels: 28.03, 26.51, 23.76, 20.70, 17.64, 14.59, 11.53, 9.70, 12.48

Legend:
- Glide Path
- Natural Condition (Most Impaired)
- Observation (Most Impaired)
- Model Projection (Most Impaired)
- Rolling Average (Most Impaired)

27

Uniform Rate of Progress Glide Path
Swanquarter - 20% Most Impaired Data Days

Uniform Rate of Progress Glide Path
Cape Romain - 20% Most Impaired Data Days

Revised

Haziness Index (Deciviews) vs Year

Data labels: 25.25, 23.96, 21.64, 19.07, 16.49, 13.91, 11.34, 9.79, 16.14

Legend:
- Glide Path
- Natural Condition (Most Impaired)
- Observation (Most Impaired)
- Model Projection (Most Impaired)
- Rolling Average (Most Impaired)

29

**Uniform Rate of Progress Glide Path
Great Smoky Mountains - 20% Most Impaired Data Days**

Revised

29.16

27.56

24.70

21.51

18.33

15.14

11.96

14.11

10.05

Haziness Index (Deciviews)

Year

Glide Path · · · · · Natural Condition (Most Impaired)
Observation (Most Impaired) · · · · Model Projection (Most Impaired)
Rolling Average (Most Impaired)

30

Uniform Rate of Progress Glide Path
James River Face - 20% Most Impaired Data Days

Uniform Rate of Progress Glide Path
Shenandoah - 20% Most Impaired Data Days

Revised

Legend:
- Glide Path
- Natural Condition (Most Impaired)
- Observation (Most Impaired)
- Model Projection (Most Impaired)
- Rolling Average (Most Impaired)

Data labels: 28.32, 26.76, 23.94, 20.80, 17.67, 14.53, 11.40, 9.52, 13.20

Uniform Rate of Progress Glide Path
Dolly Sods - 20% Most Impaired Data Days

Revised

Haziness Index (Deciviews) vs **Year**

28.29
26.67
23.77
20.54
17.31
14.08
10.86
8.92
14.18

Legend:
- Glide Path
- Natural Condition (Most Impaired)
- Observation (Most Impaired)
- Model Projection (Most Impaired)
- Rolling Average (Most Impaired)

33

Uniform Rate of Progress Glide Path
Caney Creek - 20% Most Impaired Data Days

Legend:
- Glide Path
- Natural Condition (Most Impaired)
- Observation (Most Impaired)
- Model Projection (Most Impaired)
- Rolling Average (Most Impaired)

Glide Path values: 23.99, 22.78, 20.60, 18.18, 17.23, 15.76, 13.34, 10.92, 9.47

34

Uniform Rate of Progress Glide Path
Upper Buffalo - 20% Most Impaired Data Days

Uniform Rate of Progress Glide Path
Hercules - Glade - 20% Most Impaired Data Days

Revised

Data labels on Glide Path: 25.17, 23.84, 21.46, 18.82, 16.17, 13.53, 10.89, 9.30

Model Projection label: 17.58

Legend:
— Glide Path
— Natural Condition (Most Impaired)
♦ Observation (Most Impaired)
— Model Projection (Most Impaired)
— Rolling Average (Most Impaired)

Y-axis: Haziness Index (Deciviews)
X-axis: Year

36

Uniform Rate of Progress Glide Path
Mingo - 20% Most Impaired Data Days

Uniform Rate of Progress Glide Path
Brigantine - 20% Most Impaired Data Days

Revised

Haziness Index (Deciviews) vs Year

27.48
26.04
23.52
20.73
17.94
15.15
12.36
10.69
17.70

— Glide Path
— Natural Condition (Most Impaired)
♦ Observation (Most Impaired)
— Model Projection (Most Impaired)
— Rolling Average (Most Impaired)

38

Adjusted 2028 PSAT Stacked Bar Charts

PSAT Source Apportionment Modeling

PSAT = Particulate Matter Source Apportionment Technology

Quantifies visibility impacts from individual point sources, source sectors, and geographic regions

NOx and SO_2 tagging

Used for further evaluation of AOI results

Refines information on contributions to visibility impairment

Can be used to adjust future year visibility projections to account for additional emission controls

VISTAS contract with ERG allows for up to 250 tags

PSAT SO_2 and NOx Tags (209)

Round 1 (122 tags)

- Total SO_2 tags for 10 individual VISTAS states + 3 RPOs = 13 tags
- Total NOx tags for 10 individual VISTAS states + 3 RPOs = 13 tags
- EGU point SO_2 tags for 10 individual VISTAS states + 3 RPOs = 13 tags
- EGU point NOx tags for 10 individual VISTAS states + 3 RPOs = 13 tags
- *SO_2 tags for individual VISTAS facilities = 50 tags*
- *NOx tags for individual VISTAS facilities = 20 tags*

Round 2 (87 tags)

- Non-EGU point SO_2 for 10 individual VISTAS states + 3 RPOs = 13 tags
- Non-EGU point NOx for 10 individual VISTAS states + 3 RPOs = 13 tags
- SO_2 and NOx for N/S/W/E boundaries = 8 tags
- *SO_2 tags for individual VISTAS facilities = 10 tags*
- *NOx tags for individual VISTAS facilities = 16 tags*
- *SO_2 tags for individual non-VISTAS facilities = 17 tags*
- *NOx tags for individual non-VISTAS facilities = 10 tags*

Revised State/RPO PSAT Results

- **Revised EGU Sulfate PSAT Results**

    = Original EGU Sulfate PSAT Results * SO$_2$ EGU Ratio

    $$\text{where, } SO_2 \text{ EGU Ratio} = \frac{(\text{Revised EGU } SO_2 \text{ emissions})}{(\text{Original EGU } SO_2 \text{ emissions})}$$

- **Revised NEGU Sulfate PSAT Results**

    = Original NEGU Sulfate PSAT Results * SO$_2$ NEGU Ratio

    $$\text{where, } SO_2 \text{ NEGU Ratio} = \frac{(\text{Revised NEGU } SO_2 \text{ emissions})}{(\text{Original NEGU } SO_2 \text{ emissions})}$$

Revised State/RPO PSAT Results
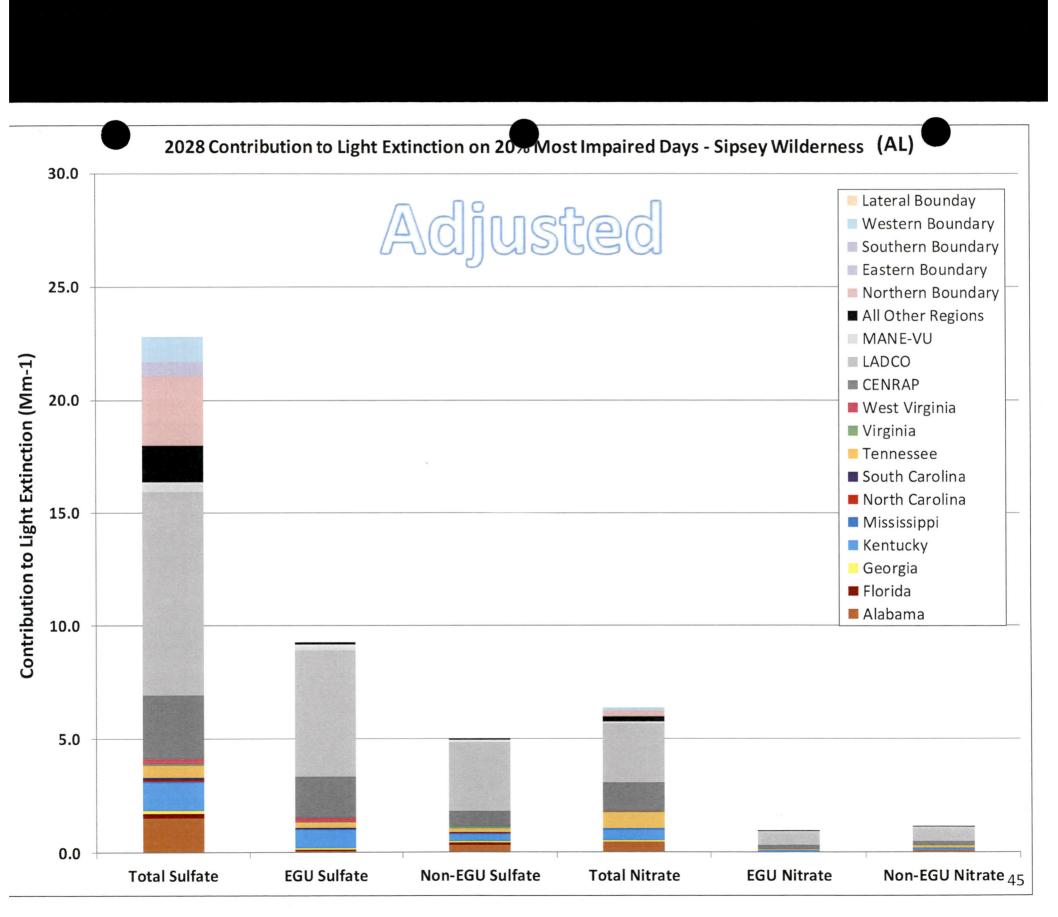
- **Revised EGU Nitrate PSAT Results**
  = Original EGU Nitrate PSAT Results * NOx EGU Ratio

$$\text{where, NOx EGU Ratio} = \frac{(\text{Revised EGU NOx emissions})}{(\text{Original EGU NOx emissions})}$$
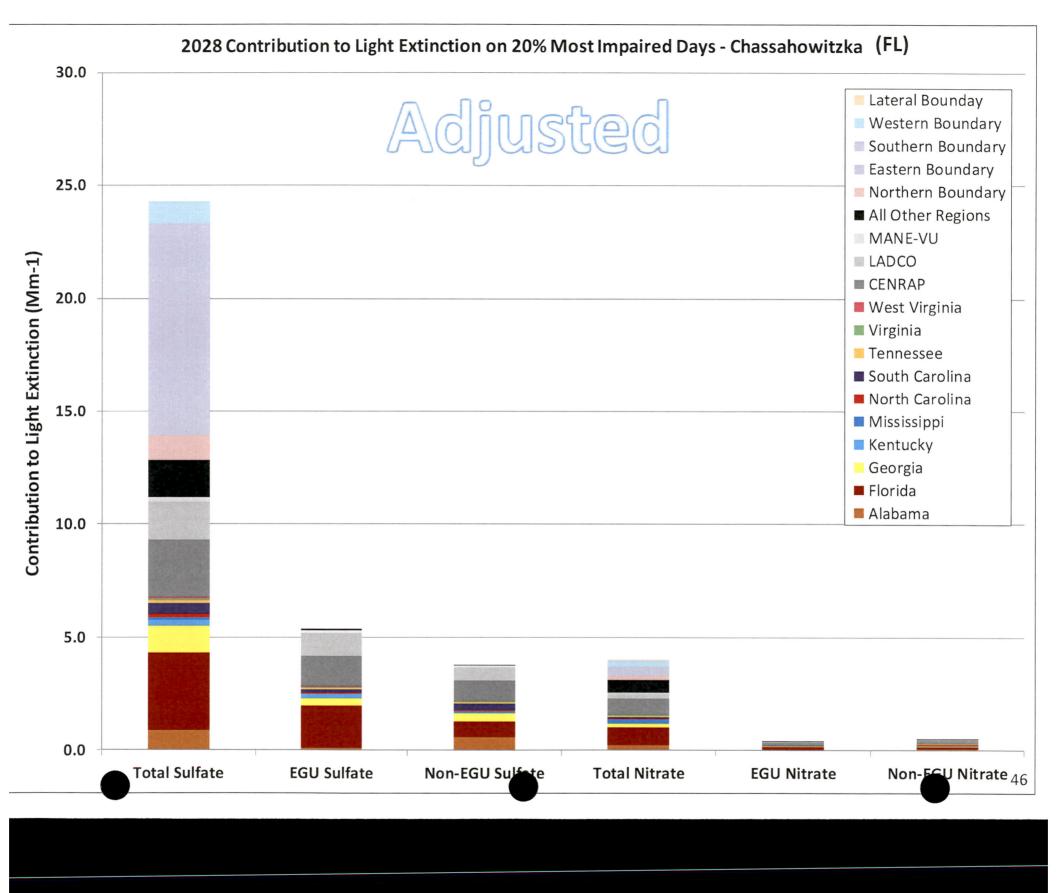
- **Revised NEGU Nitrate PSAT Results**
  = Original NEGU Nitrate PSAT Results * NOx NEGU Ratio

$$\text{where, NOx NEGU Ratio} = \frac{(\text{Revised NEGU NOx emissions})}{(\text{Original NEGU NOx emissions})}$$
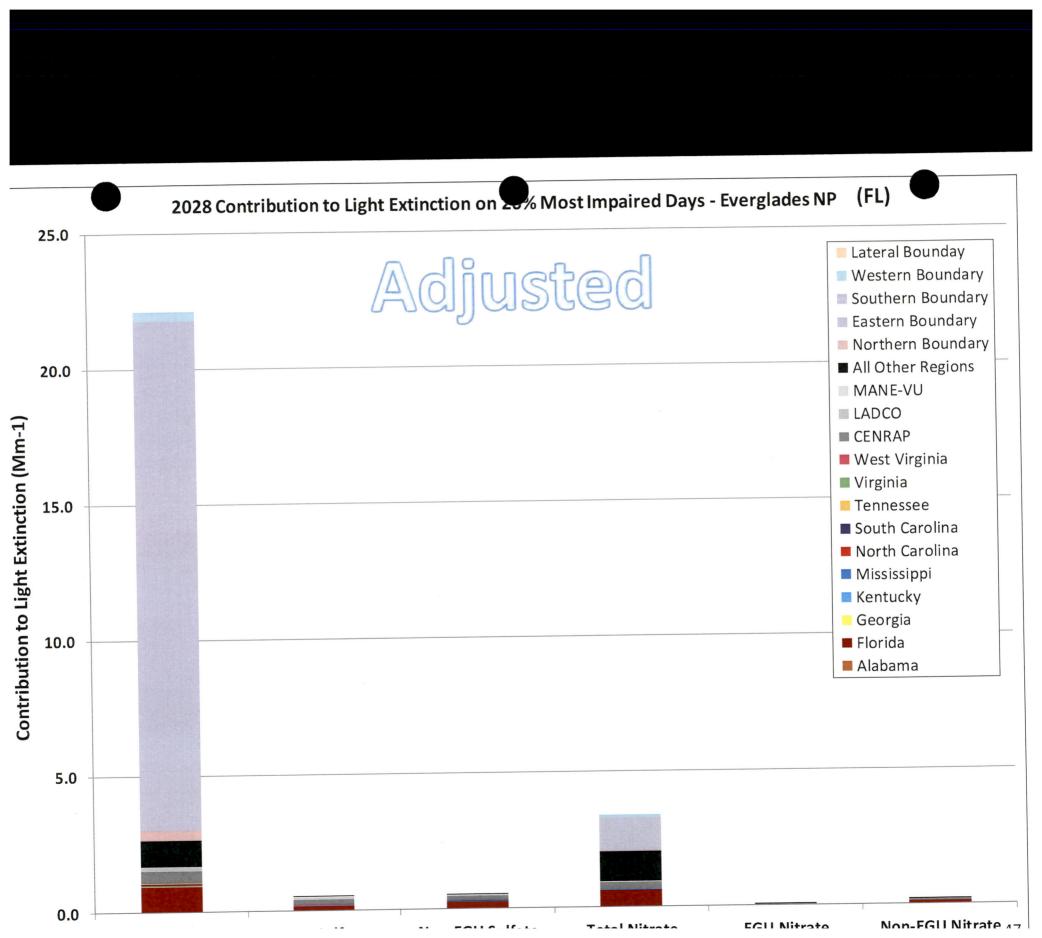
PSAT Adjustment Ratios
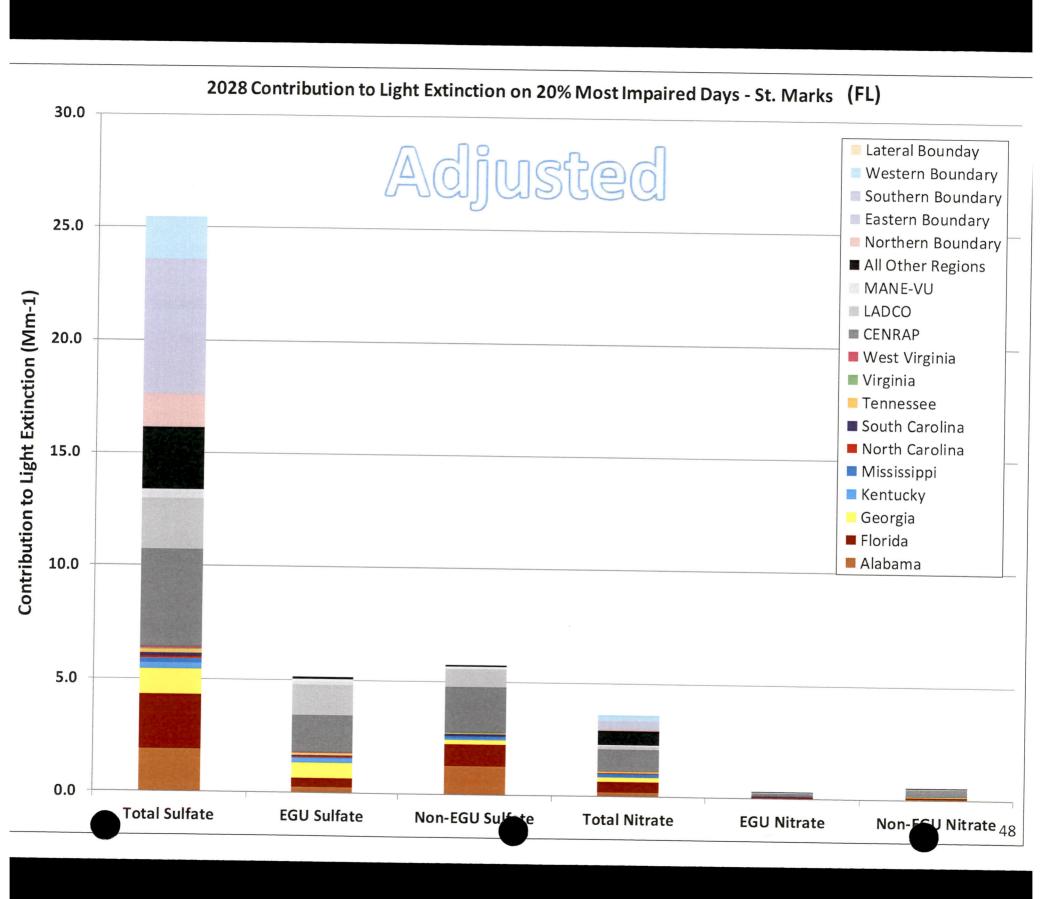
State/RPO	SO$_2$ EGU Ratio	SO$_2$ NEGU Ratio	NOx EGU Ratio	NOx NEGU Ratio
AL	0.540	0.708	0.744	0.950
FL	0.841	0.829	0.954	1.077
GA	0.951	1.000	0.949	1.000
KY	0.881	0.850	0.889	0.999
MS	0.463	0.363	0.668	1.023
NC	0.485	0.953	0.753	0.998
SC	1.000	1.000	1.018	0.997
TN	0.828	0.973	0.775	0.982
VA	0.605	1.000	0.872	1.000
WV	0.826	1.071	1.067	1.000
CENSARA	0.494	1.000	0.706	1.000
LADCO	0.636	1.000	0.764	1.000
MANE-VU	0.467	0.810	0.794	1.000

For detailed calculations, see Handout - Roadmap located at:
https://www.metro4-sesarm.org/content/vistas-regional-haze-program

44

2028 Contribution to Light Extinction on 20% Most Impaired Days - Sipsey Wilderness (AL)

Adjusted

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1), scale 0.0 to 30.0

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

45

2028 Contribution to Light Extinction on 20% Most Impaired Days - Chassahowitzka (FL)

2028 Contribution to Light Extinction on 20% Most Impaired Days - Everglades NP (FL)

2028 Contribution to Light Extinction on 20% Most Impaired Days - St. Marks (FL)

2028 Contribution to Light Extinction on 20% Most Impaired Days - Cohutta Wilderness (GA)

Adjusted

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1), from 0.0 to 25.0

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

2028 Contribution to Light Extinction on 20% Most Impaired Days - Okefenokee (GA)

Adjusted

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

50

2028 Contribution to Light Extinction on 20% Most Impaired Days - Wolf Island (GA)

2028 Contribution to Light Extinction on 20% Most Impaired Days - Mammoth Cave NP (KY)

2028 Contribution to Light Extinction on 20% Most Impaired Days - Linville Gorge Wilderness (NC)

Legend:
- Lateral Boundary
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

Y-axis: Contribution to Light Extinction (Mm-1), 0.0 to 25.0

2028 Contribution to Light Extinction on 20% Most Impaired Days - Shining Rock Wilderness (NC)

Adjusted

Legend:
- Lateral Boundary
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1), scale 0.0 to 25.0

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

54

2028 Contribution to Light Extinction on 20% Most Impaired Days - Swanquarter (NC)

2028 Contribution to Light Extinction on 20% Most Impaired Days - Cape Romain (SC)

Adjusted

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

2028 Contribution to Light Extinction on 20% Most Impaired Days - Great Smoky Mountains NP (..., NC)

Adjusted

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

57

2028 Contribution to Light Extinction on 20% Most Impaired Days - Joyce-Kilmer-Slickrock (TN/NC) Wilderness

Adjusted

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1), ranging from 0.0 to 25.0

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

2028 Contribution to Light Extinction on 20% Most Impaired Days - James River Face Wilderness (...)

Adjusted

Contribution to Light Extinction (Mm-1)

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Categories:
- Total Sulfate
- EGU Sulfate
- Non-EGU Sulfate
- Total Nitrate
- EGU Nitrate
- Non-EGU Nitrate

2028 Contribution to Light Extinction on 20% Most Impaired Days - Shenandoah NP (VA)

Adjusted

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1), scale 0.0 to 30.0

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

60

2028 Contribution to Light Extinction on 20% Most Impaired Days - Dolly Sods Wilderness (Wv)

Adjusted

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

61

2028 Contribution to Light Extinction on 20% Most Impaired Days - Otter Creek Wilderness (WV)

2028 Contribution to Light Extinction on 20% Most Impaired Days - Breton (LA)

2028 Contribution to Light Extinction on 20% Most Impaired Days - Caney Creek Wilderness (AR)

2028 Contribution to Light Extinction on 20% Most Impaired Days - Upper Buffalo Wilderness (A...

2028 Contribution to Light Extinction on 20% Most Impaired Days - Hercules-Glades Wilderness (MO)

2028 Contribution to Light Extinction 20% Most Impaired Days - Mingo (MO)

2028 Contribution to Light Extinction on 20% Most Impaired Days - Brigantine (NJ)

Adjusted

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1), ranging from 0.0 to 30.0

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

Reasonable Progress Screening Analysis

Reasonable Progress Screening Approach

1. The VISTAS reasonable progress work started with AOI screening (Q/d * EWRT) to rank facilities based on their sulfate and nitrate contributions at each Class I area.

2. These rankings were used to identify 87 individual facilities for PSAT tagging. PSAT tagging was used to determine the sulfate and nitrate contributions from each facility at each Class I area in the VISTAS_12 domain.

3. Each individual VISTAS state will apply a PSAT contribution threshold based on the facility sulfate and facility nitrate impacts (separately, not combined) divided by the total impact of sulfate + nitrate from all point sources to determine which sources may need to be considered for a four-factor analysis.
    - If sulfate contribution ≥ 1.00% ➔ SO_2 Four-Factor Analysis
    - If nitrate contribution ≥ 1.00% ➔ NOx Four-Factor Analysis

Why 1% Threshold?

- In the Round 1 Regional Haze SIPs, many VISTAS states used the AOI approach and a 1% threshold on a <u>Unit</u> basis.
  - Round 2 uses the AOI/PSAT approach and a ≥ 1.00% PSAT threshold based on a <u>Facility</u> basis.
    - This will pull in more facilities compared to a Unit basis.
  - Round 2 uses 2028 emissions (lower than 2018)
    - This will pull in facilities with smaller visibility impacts (in Mm^{-1}) compared to Round 1.
- This approach results in a reasonable number of sources that can be evaluated with limited state resources and focuses on the sources with the largest impacts.
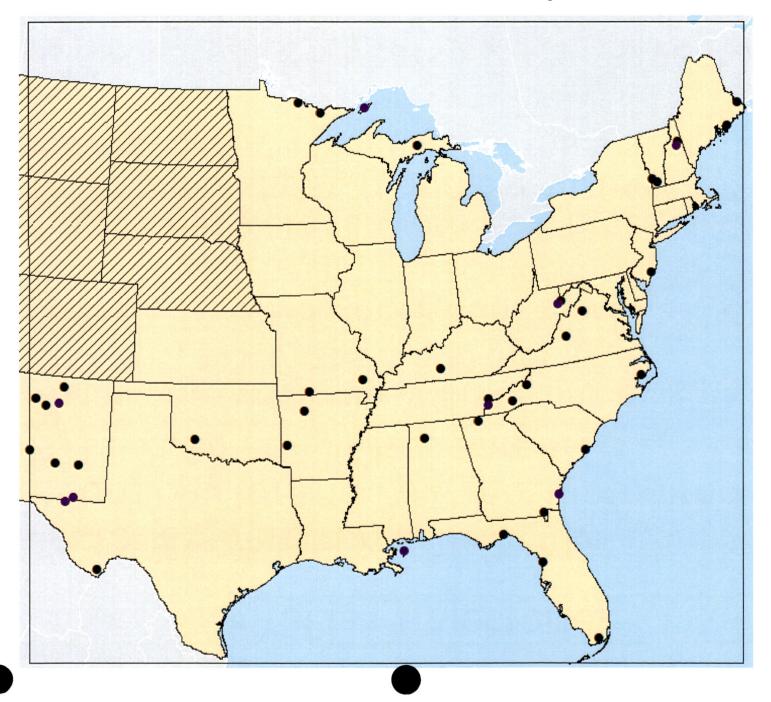
Area of Influence (AOI) Analysis

- Evaluates emissions (Q), distance to Class I area (d), and extinction weighted residence time (EWRT) in model grid cells (point) or counties (source categories)
- Formula: (Q/d)*EWRT
- Establishes each county's and each facility's contribution to light extinction at each Class I area on the 20% most impaired days
- Can use contributions to rank and screen facilities for the four-factor analysis
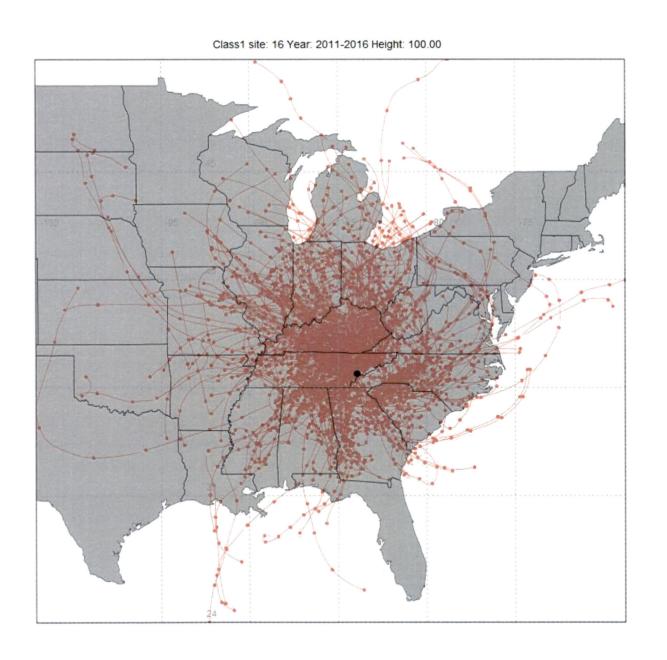
HYSPLIT Trajectories

- Trajectories were run using NAM-12 meteorology for the 20% most impaired days in 2011-2016 at 44 Class I areas.
    - Trajectories were run with starting heights of 100, 500, 1,000, and 1,500 meters.
    - Trajectories were run 72 hours backwards in time for each height at each location.
    - Trajectories were run with start times of 12AM (midnight of the start of the day), 6AM, 12PM, 6PM, and 12AM (midnight at the end of the day) local time.
- 44 Class I areas x 6 years x 24 days/year x 4 heights x 5 start times = **126,720 trajectories**
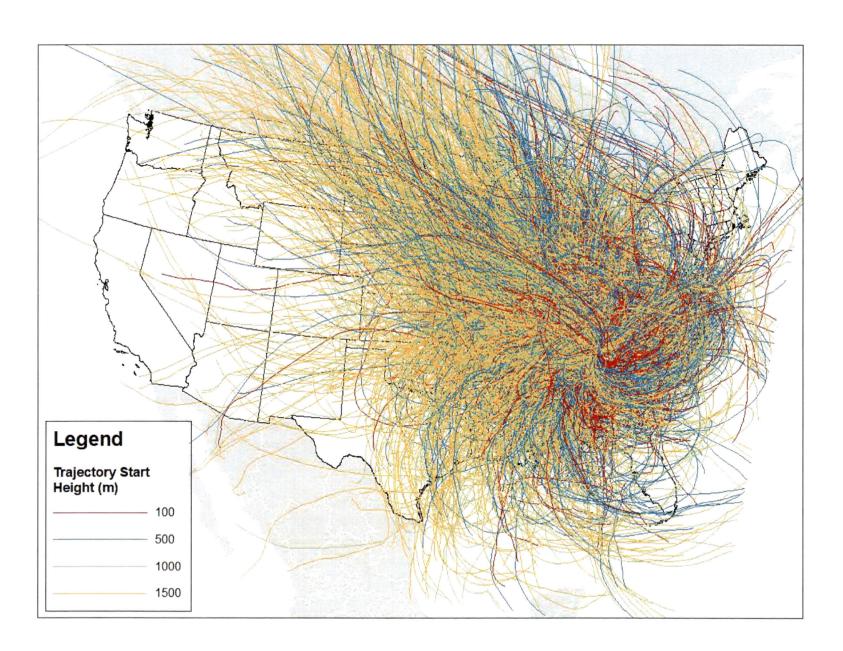
Class I Areas Analyzed

100 Meter Trajectories at GRSM

Class1 site: 16 Year: 2011-2016 Height: 100.00

All Trajectories at GRSM

Legend

Trajectory Start Height (m)

——— 100
——— 500
——— 1000
——— 1500

Residence Time for GRSM

Hours by hexbin; Class I site: 16; Year: 2011-2016; all heights

Sulfate EWRT at GRSM

Legend

EWRT SO$_4$ as Percent of Total (Grid)

- 0% - 0.01%
- 0.02% - 0.1%
- 0.11% - 0.25%
- 0.26% - 0.5%
- 0.51% - 0.75%
- 0.76% - 1%
- 1.01% - 2%
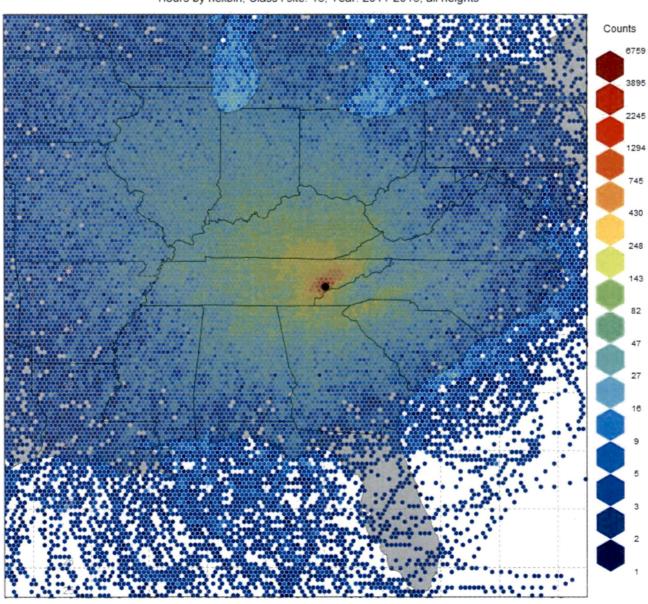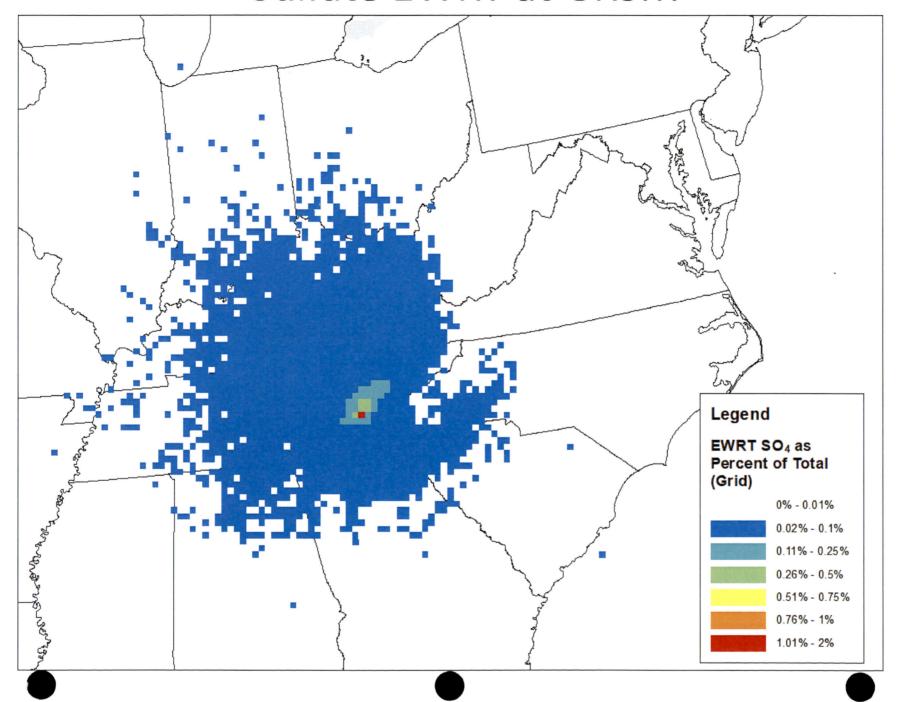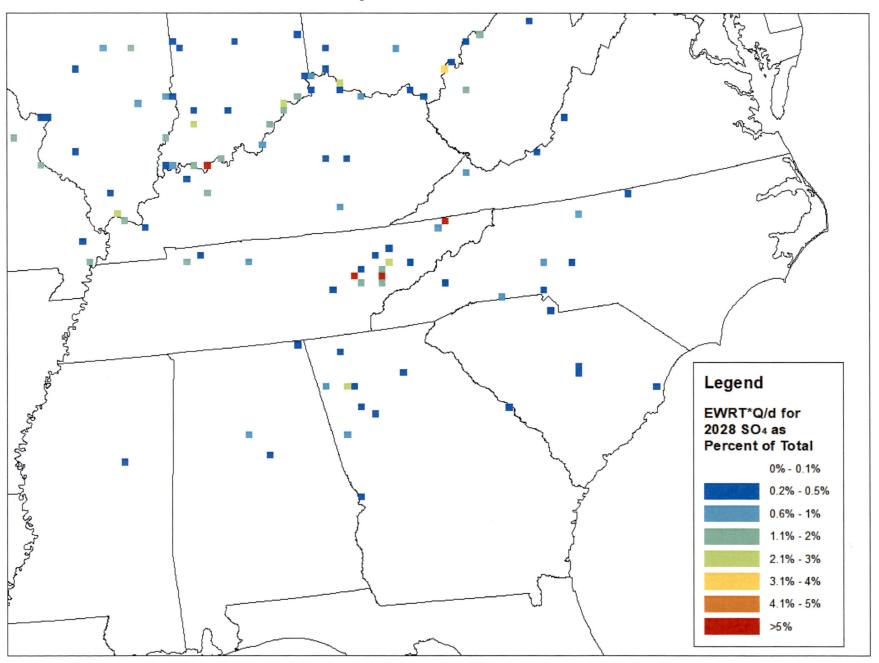
Sulfate Q/d*EWRT at GRSM

AOI Point Contributions for Cohutta

State	FACILITY NAME	DISTANCE (km)	NOx_2028 (tons/year)	SO2_2028 (tons/year)	NOx Contribution	SO2 Contribution
GA	Ga Power Company - Plant Bowen	78.0	6,643.3	10,453.4	1.15%	19.58%
IN	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	410.1	8,806.8	30,536.3	0.13%	4.68%
GA	International Paper – Rome	87.4	1,773.4	1,791.0	0.18%	4.66%
IN	Gibson	487.1	12,280.3	23,117.2	0.10%	2.31%
IN	INDIANAPOLIS POWER & LIGHT PETERSBURG	477.0	10,665.3	18,141.9	0.16%	2.18%
KY	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	457.2	7,007.3	19,504.7	0.07%	2.18%
TN	TVA KINGSTON FOSSIL PLANT	124.0	1,687.4	1,886.1	0.13%	2.17%
OH	General James M. Gavin Power Plant (0627010056)	512.0	8,122.5	41,595.8	0.02%	1.71%
TN	TVA CUMBERLAND FOSSIL PLANT	327.0	4,916.5	8,427.3	0.09%	1.38%
KY	Big Rivers Electric Corp - Wilson Station	369.0	1,151.9	6,934.2	0.01%	1.07%
OH	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	454.6	7,150.0	22,133.9	0.06%	1.05%
GA	Ga Power Company - Plant Wansley	156.8	2,052.5	4,856.0	0.04%	1.05%
KY	KY Utilities Co - Ghent Station	441.5	7,939.9	10,169.3	0.08%	1.05%
IL	Joppa Steam	466.9	4,706.3	20,509.3	0.02%	1.04%
GA	Mohawk Industries Inc	32.0	66.5	77.1	0.07%	1.02%
TN	EASTMAN CHEMICAL COMPANY	269.8	6,900.3	6,420.2	0.09%	0.99%
MO	AMEREN MISSOURI-LABADIE PLANT	695.4	9,685.5	41,740.3	0.01%	0.96%
IL	Newton	564.0	1,934.9	10,631.6	0.01%	0.91%
GA	Chemical Products Corporation	71.9	19.5	513.8	0.00%	0.89%
IN	INDIANA KENTUCKY ELECTRIC CORPORATION	444.4	6,188.5	9,038.1	0.04%	0.76%

AOI Point Contributions for Okefenokee

State	FACILITY NAME	DISTANCE (km)	NOx_2028 (tons/year)	SO2_2028 (tons/year)	NOx Contribution	SO2 Contribution
FL	WHITE SPRINGS AGRICULTURAL CHEMICALS,INC	71.5	112.4	2,745.0	0.03%	14.63%
FL	ROCK TENN CP, LLC	64.8	2,316.8	2,606.7	0.88%	12.82%
FL	JEA	65.6	651.8	2,094.5	0.18%	6.60%
FL	SEMINOLE ELECTRIC COOPERATIVE, INC.	121.4	917.8	3,713.4	0.07%	3.25%
FL	IFF CHEMICAL HOLDINGS, INC.	56.8	37.7	898.9	0.01%	3.25%
FL	RAYONIER PERFORMANCE FIBERS LLC	63.4	2,327.1	562.0	0.90%	2.82%
GA	**International Paper - Savannah**	178.9	1,560.7	3,945.4	0.08%	2.81%
FL	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	153.5	1,830.7	1,520.4	0.14%	2.18%
FL	RENESSENZ LLC	59.8	66.3	569.5	0.02%	1.96%
FL	DUKE ENERGY FLORIDA, INC. (DEF)	205.0	2,489.8	5,306.4	0.06%	1.40%
AL	Sanders Lead Co	384.6	121.7	7,951.1	0.00%	1.11%
GA	**Georgia-Pacific Consumer Products LP (Savannah River Mill)**	197.2	351.5	1,860.2	0.01%	1.05%
GA	**Ga Power Company - Plant Bowen**	458.1	6,643.3	10,453.4	0.05%	1.02%
GA	**Brunswick Cellulose Inc**	75.3	1,554.5	294.2	0.34%	1.01%
SC	ALUMAX OF SOUTH CAROLINA	322.7	108.1	3,751.7	0.00%	0.97%
GA	**PCA Valdosta Mill**	112.7	1,032.6	485.7	0.09%	0.85%
SC	SANTEE COOPER CROSS GENERATING STATION	348.1	3,273.5	4,281.2	0.05%	0.85%
FL	CITY OF GAINESVILLE, GRU	111.7	410.0	881.4	0.03%	0.79%
SC	KAPSTONE CHARLESTON KRAFT LLC	314.9	2,355.8	1,863.7	0.06%	0.65%
GA	**Ga Power Company - Plant Wansley**	403.7	2,052.5	4,856.0	0.02%	0.65%

AOI Point Contributions for Wolf Island

State	FACILITY NAME	DISTANCE (km)	NOx_2028 (tons/year)	SO2_2028 (tons/year)	NOx Contribution	SO2 Contribution
GA	Brunswick Cellulose Inc	27.9	1,554.5	294.2	2.94%	8.84%
FL	ROCK TENN CP, LLC	74.9	2,316.8	2,606.7	0.39%	8.56%
GA	International Paper - Savannah	85.9	1,560.7	3,945.4	0.24%	7.53%
FL	JEA	105.1	651.8	2,094.5	0.09%	4.43%
GA	Georgia-Pacific Consumer Products LP (Savannah River Mill)	109.9	351.5	1,860.2	0.03%	2.65%
FL	WHITE SPRINGS AGRICULTURAL CHEMICALS,INC	173.6	112.4	2,745.0	0.01%	1.97%
SC	ALUMAX OF SOUTH CAROLINA	223.0	108.1	3,751.7	0.00%	1.84%
FL	RAYONIER PERFORMANCE FIBERS LLC	77.4	2,327.1	562.0	0.38%	1.79%
FL	SEMINOLE ELECTRIC COOPERATIVE, INC.	181.4	917.8	3,713.4	0.02%	1.77%
OH	General James M. Gavin Power Plant (0627010056)	845.3	8,122.5	41,595.8	0.02%	1.71%
SC	SANTEE COOPER CROSS GENERATING STATION	251.0	3,273.5	4,281.2	0.09%	1.59%
GA	Southern States Phosphate & Fertilizer	84.1	1.0	597.1	0.00%	1.55%
FL	IFF CHEMICAL HOLDINGS, INC.	118.5	37.7	898.9	0.00%	1.22%
FL	DUKE ENERGY FLORIDA, INC. (DEF)	296.6	2,489.8	5,306.4	0.04%	1.19%
GA	Ga Power Company - Plant Bowen	458.1	6,643.3	10,453.4	0.03%	1.08%
GA	Savannah Sugar Refinery	89.9	521.6	582.0	0.08%	1.06%
SC	INTERNATIONAL PAPER EASTOVER	288.7	1,780.3	3,212.9	0.05%	0.95%
GA	Ga Power Company - Plant McManus	27.1	72.2	30.1	0.14%	0.93%
SC	KAPSTONE CHARLESTON KRAFT LLC	213.6	2,355.8	1,863.7	0.09%	0.89%
PA	GENON NE MGMT CO/KEYSTONE STA	1,048.6	6,578.5	56,939.2	0.01%	0.84%

Georgia Tagging for PSAT

- ## Sources in Georgia (≥ 2% threshold)
  - Ga Power Company – Plant Bowen
  - International Paper – Rome (aka TEMPLE INLAND)
  - International Paper – Savannah
  - Brunswick Cellulose Inc
  - Georgia-Pacific Consumer Products LP (Savannah River Mill)

- ## Sources outside Georgia (≥ 4% threshold)
  - INDIANA MICHIGAN POWER DBA AEP ROCKPORT (IN)
  - ROCK TENN CP, LLC (FL)
  - JEA (FL)

AOI Screening Summary

State	Threshold	Notes
AL	2%	Sulfate only
FL	5%	Sulfate or nitrate, plus Gulf Crist, Mosaic Bartow, Mosaic New Wales, and Mosaic Riverview
GA	2% - 4%	Sulfate or nitrate, 2% threshold for GA facilities, 4% threshold for facilities outside GA
KY	2%	Sulfate or nitrate
MS	2%	Sulfate or nitrate
NC	3%	Sulfate + nitrate
SC	2% - 5%	2% for sulfate, 5% for nitrate, plus Santee Cooper Winyah, International Paper Georgetown, and SCE&G Williams
TN	3%	Sulfate + nitrate, plus CEMEX
VA	2%	Sulfate + nitrate
WV	0.2%	Sulfate or nitrate

PSAT Source Apportionment Modeling

- Quantifies visibility impacts from individual point sources, source sectors, and geographic regions
- NOx and SO_2 tagging
- Used for further evaluation of AOI results
- Refines information on contributions to visibility impairment
- Can be used to adjust future year visibility projections to account for additional emission controls
- VISTAS contract with ERG allows for up to 250 tags

PSAT SO$_2$ and NOx Tags (209)

Round 1 (122 tags)
- *Total SO$_2$ tags for 10 individual VISTAS states + 3 RPOs = 13 tags*
- *Total NOx tags for 10 individual VISTAS states + 3 RPOs = 13 tags*
- *EGU point SO$_2$ tags for 10 individual VISTAS states + 3 RPOs = 13 tags*
- *EGU point NOx tags for 10 individual VISTAS states + 3 RPOs = 13 tags*
- SO$_2$ tags for individual VISTAS facilities = 50 tags
- NOx tags for individual VISTAS facilities = 20 tags

Round 2 (87 tags)
- *Non-EGU point SO$_2$ for 10 individual VISTAS states + 3 RPOs = 13 tags*
- *Non-EGU point NOx for 10 individual VISTAS states + 3 RPOs = 13 tags*
- *SO$_2$ and NOx for N/S/W/E boundaries = 8 tags*
- SO$_2$ tags for individual VISTAS facilities = 10 tags
- NOx tags for individual VISTAS facilities = 16 tags
- SO$_2$ tags for individual non-VISTAS facilities = 17 tags
- NOx tags for individual non-VISTAS facilities = 10 tags

➡ 87 Total Facility Tags (both SO$_2$ and NOx)

Facility Tags (AL, FL, GA)

Facility State	Facility RPO	FACILITY_ID_STD	FACILITY_NAME_STD	SO2 (TPY)	NOx (TPY)
AL	VISTAS	01097-949811	Akzo Nobel Chemicals Inc	3,335.72	20.71
AL	VISTAS	01097-1056111	Ala Power - Barry	6,033.17	2,275.76
AL	VISTAS	01129-1028711	American Midstream Chatom, LLC	3,106.38	425.87
AL	VISTAS	01073-1018711	DRUMMOND COMPANY, INC.	2,562.17	1,228.55
AL	VISTAS	01053-7440211	Escambia Operating Company LLC	18,974.39	349.32
AL	VISTAS	01053-985111	Escambia Operating Company LLC	8,589.60	149.64
AL	VISTAS	01103-1000011	Nucor Steel Decatur LLC	170.23	331.24
AL	VISTAS	01109-985711	Sanders Lead Co	7,951.06	121.71
AL	VISTAS	01097-1061611	Union Oil of California - Chunchula Gas Plant	2,573.15	349.23
FL	VISTAS	12123-752411	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1,520.42	1,830.71
FL	VISTAS	12086-900111	CEMEX CONSTRUCTION MATERIALS FL. LLC.	29.51	910.36
FL	VISTAS	12017-640611	DUKE ENERGY FLORIDA, INC. (DEF)	5,306.41	2,489.85
FL	VISTAS	12086-900011	FLORIDA POWER & LIGHT (PTF)	13.05	170.61
FL	VISTAS	12033-752711	GULF POWER - Crist	2,615.65	2,998.39
FL	VISTAS	12086-3532711	HOMESTEAD CITY UTILITIES	0.00	97.09
FL	VISTAS	12031-640211	JEA	2,094.48	651.79
FL	VISTAS	12105-717711	MOSAIC FERTILIZER LLC	7,900.67	310.42
FL	VISTAS	12057-716411	MOSAIC FERTILIZER, LLC	3,034.06	159.71
FL	VISTAS	12105-919811	MOSAIC FERTILIZER, LLC	4,425.56	141.02
FL	VISTAS	12089-845811	RAYONIER PERFORMANCE FIBERS LLC	561.97	2,327.10
FL	VISTAS	12089-753711	ROCK TENN CP, LLC	2,606.72	2,316.77
FL	VISTAS	12005-535411	ROCKTENN CP LLC	2,590.88	1,404.89
FL	VISTAS	12129-2731711	TALLAHASSEE CITY PURDOM GENERATING STA.	2.86	121.46
FL	VISTAS	12057-538611	TAMPA ELECTRIC COMPANY (TEC)	6,084.90	2,665.03
FL	VISTAS	12086-899911	TARMAC AMERICA LLC	9.38	879.70
FL	VISTAS	12047-769711	WHITE SPRINGS AGRICULTURAL CHEMICALS,INC	3,197.77	112.41
GA	VISTAS	13127-3721011	Brunswick Cellulose Inc	294.20	1,554.51
GA	VISTAS	13015-2813011	Ga Power Company - Plant Bowen	10,453.41	6,643.32
GA	VISTAS	13103-536311	Georgia-Pacific Consumer Products LP (Savannah River Mill)	1,860.18	351.52
GA	VISTAS	13051-3679811	International Paper – Savannah	3,945.38	1,560.73
GA	VISTAS	13115-539311	TEMPLE INLAND	1,791.00	1,773.35
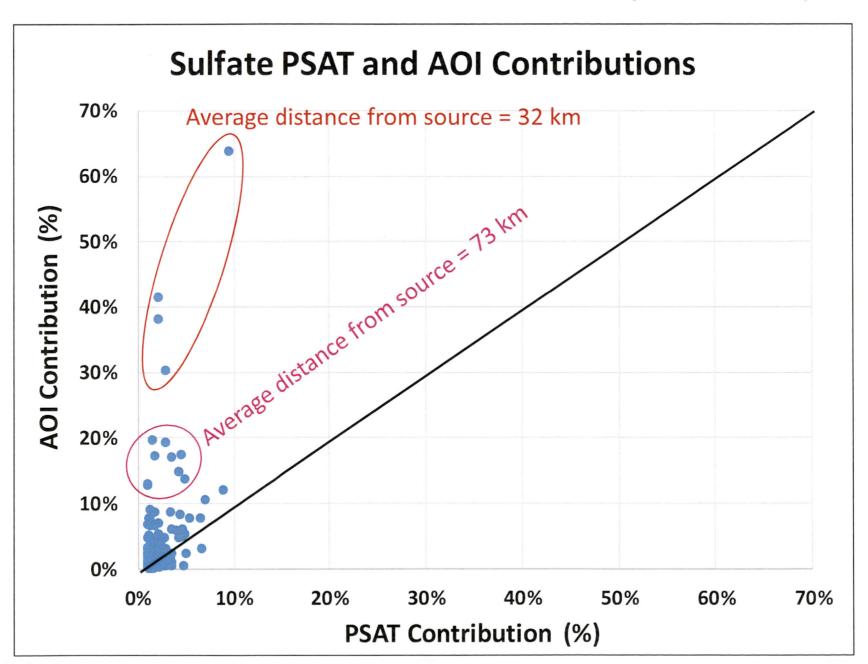
Facility Tags (KY, MS, NC, SC, TN, VA)

Facility State	Facility RPO	FACILITY_ID_STD	FACILITY_NAME_STD	SO2 (TPY)	NOx (TPY)
KY	VISTAS	21183-5561611	Big Rivers Electric Corp - Wilson Station	6,934.16	1,151.95
KY	VISTAS	21091-7352411	Century Aluminum of KY LLC	5,044.16	197.66
KY	VISTAS	21177-5196711	Tennessee Valley Authority - Paradise Fossil Plant	3,011.01	3,114.52
KY	VISTAS	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	19,504.75	7,007.34
MS	VISTAS	28059-8384311	Chevron Products Company, Pascagoula Refinery	741.60	1,534.12
MS	VISTAS	28059-6251011	Mississippi Power Company, Plant Victor J Daniel	231.92	3,829.72
NC	VISTAS	37087-7920511	Blue Ridge Paper Products - Canton Mill	1,127.07	2,992.37
NC	VISTAS	37117-8049311	Domtar Paper Company, LLC	687.45	1,796.49
NC	VISTAS	37035-8370411	Duke Energy Carolinas, LLC - Marshall Steam Station	4,139.21	7,511.31
NC	VISTAS	37013-8479311	PCS Phosphate Company, Inc. - Aurora	4,845.90	495.58
NC	VISTAS	37023-8513011	SGL Carbon LLC	261.64	21.69
SC	VISTAS	45015-4834911	ALUMAX OF SOUTH CAROLINA	3,751.69	108.08
SC	VISTAS	45043-5698611	INTERNATIONAL PAPER GEORGETOWN MILL	2,767.52	2,031.26
SC	VISTAS	45019-4973611	KAPSTONE CHARLESTON KRAFT LLC	1,863.65	2,355.82
SC	VISTAS	45015-4120411	SANTEE COOPER CROSS GENERATING STATION	4,281.17	3,273.47
SC	VISTAS	45043-6652811	SANTEE COOPER WINYAH GENERATING STATION	2,246.86	1,772.53
SC	VISTAS	45015-8306711	SCE&G WILLIAMS	392.48	992.73
TN	VISTAS	47093-4979911	Cemex - Knoxville Plant	121.47	711.50
TN	VISTAS	47163-3982311	EASTMAN CHEMICAL COMPANY	6,420.16	6,900.33
TN	VISTAS	47105-4129211	TATE & LYLE, Loudon	472.76	883.25
TN	VISTAS	47001-6196011	TVA BULL RUN FOSSIL PLANT	622.54	964.16
TN	VISTAS	47161-4979311	TVA CUMBERLAND FOSSIL PLANT	8,427.33	4,916.52
TN	VISTAS	47145-4979111	TVA KINGSTON FOSSIL PLANT	1,886.09	1,687.38
VA	VISTAS	51027-4034811	Jewell Coke Company LLP	5,090.95	520.17
VA	VISTAS	51580-5798711	Meadwestvaco Packaging Resource Group	2,115.31	1,985.69
VA	VISTAS	51023-5039811	Roanoke Cement Company	2,290.17	1,972.97
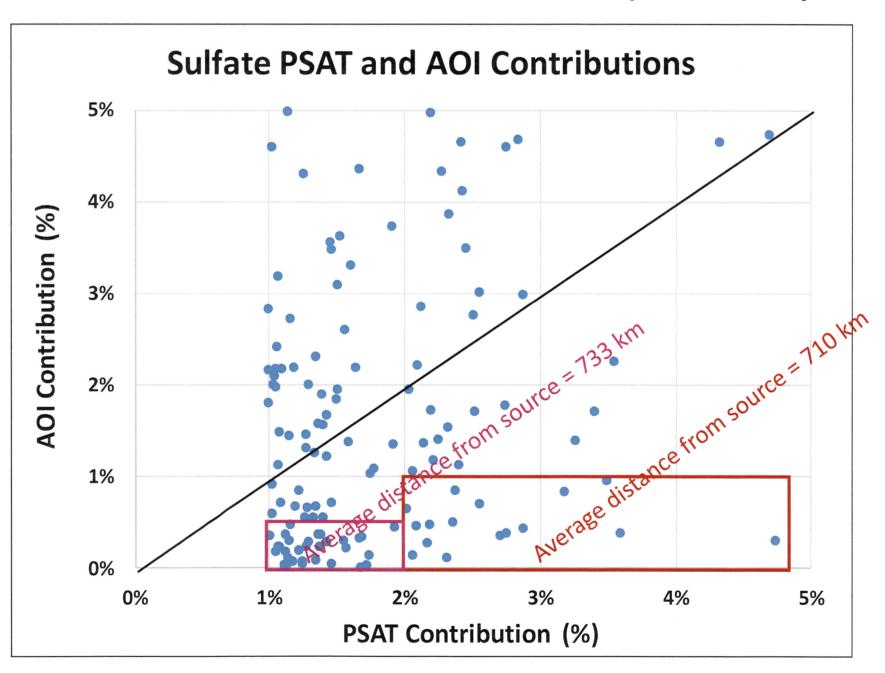
Facility Tags (WV, AR, MO, MD, PA, IL, IN, OH)

Facility State	Facility RPO	FACILITY_ID_STD	FACILITY_NAME_STD	SO2 (TPY)	NOx (TPY)
WV	VISTAS	54033-6271711	ALLEGHENY ENERGY SUPPLY CO, LLC-HARRISON	10,082.94	11,830.88
WV	VISTAS	54049-4864511	AMERICAN BITUMINOUS POWER-GRANT TOWN PLT	2,210.25	1,245.10
WV	VISTAS	54079-6789111	APPALACHIAN POWER COMPANY - JOHN E AMOS PLANT	10,984.24	4,878.10
WV	VISTAS	54023-6257011	Dominion Resources, Inc. - MOUNT STORM POWER STATION	2,123.64	1,984.14
WV	VISTAS	54041-6900311	EQUITRANS - COPLEY RUN CS 70	0.10	511.06
WV	VISTAS	54083-6790711	FILES CREEK 6C4340	0.15	643.35
WV	VISTAS	54083-6790511	GLADY 6C4350	0.11	343.29
WV	VISTAS	54093-6327811	KINGSFORD MANUFACTURING COMPANY	16.96	140.88
WV	VISTAS	54061-16320111	LONGVIEW POWER	2,313.73	1,556.57
WV	VISTAS	54051-6902311	MITCHELL PLANT	5,372.40	2,719.62
WV	VISTAS	54061-6773611	MONONGAHELA POWER CO.- FORT MARTIN POWER	4,881.87	13,743.32
WV	VISTAS	54073-4782811	MONONGAHELA POWER CO-PLEASANTS POWER STA	16,817.43	5,497.37
WV	VISTAS	54061-6773811	MORGANTOWN ENERGY ASSOCIATES	828.64	655.58
AR	CENRAP	05063-1083411	ENTERGY ARKANSAS INC-INDEPENDENCE PLANT	32,050.48	14,133.10
MO	CENRAP	29143-5363811	NEW MADRID POWER PLANT-MARSTON	16,783.71	4,394.10
MD	MANE-VU	24001-7763811	Luke Paper Company	22,659.84	3,607.00
PA	MANE-VU	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	56,939.25	6,578.47
PA	MANE-VU	42063-3005211	HOMER CITY GEN LP/ CENTER TWP	11,865.70	5,215.96
PA	MANE-VU	42063-3005111	NRG WHOLESALE GEN/SEWARD GEN STA	8,880.26	2,254.64
IL	Midwest RPO	17127-7808911	Joppa Steam	20,509.28	4,706.35
IN	Midwest RPO	18173-8183111	Alcoa Warrick Power Plt Agc Div of AL	5,071.28	11,158.55
IN	Midwest RPO	18051-7363111	Gibson	23,117.23	12,280.34
IN	Midwest RPO	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	30,536.33	8,806.77
IN	Midwest RPO	18125-7362411	INDIANAPOLIS POWER & LIGHT PETERSBURG	18,141.88	10,665.27
IN	Midwest RPO	18129-8166111	Sigeco AB Brown South Indiana Gas & Ele	7,644.70	1,578.59
OH	Midwest RPO	39081-8115711	Cardinal Power Plant (Cardinal Operating Company) (0641050002)	7,460.79	2,467.31
OH	Midwest RPO	39031-8010811	Conesville Power Plant (0616000000)	6,356.23	9,957.87
OH	Midwest RPO	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	22,133.90	7,149.97
OH	Midwest RPO	39053-8148511	General James M. Gavin Power Plant (0627010056)	41,595.81	8,122.51
OH	Midwest RPO	39053-7983011	Ohio Valley Electric Corp., Kyger Creek Station (0627000003)	3,400.14	9,143.84

Sulfate AOI vs. Sulfate PSAT (≥ 1.00%)

Sulfate PSAT and AOI Contributions

Average distance from source = 32 km

Average distance from source = 73 km

AOI Contribution (%)

PSAT Contribution (%)

Sulfate AOI vs. Sulfate PSAT (≥ 1.00%)

Sulfate PSAT and AOI Contributions

AOI vs. PSAT Summary

- AOI tends to overestimate impacts for facilities near the Class I area.
- AOI tends to underestimate impacts for facilities far away from the Class I area.
  - AOI uses 72-hour back trajectories, sulfate can last for weeks and travel hundreds to thousands of km.
- PSAT is the most reliable modeling tool for tracking facility contributions to visibility impairment at Class I areas.

PSAT Reasonable Progress Screening

- The **facility sulfate and nitrate contributions (Mm^{-1})** from the individual 87 tagged facilities should not change unless a facility has reduced or increased SO_2 and/or NOx emissions.
- The updated 2028 CAMx modeling will impact the **total sulfate and total nitrate contribution** from point sources at each Class I area since the SO_2 and NOx emissions have decreased.
    - The facility percent contribution will increase even if the facility emissions do not change since the denominator will decrease

Facility Sulfate Contribution (%) =

$$\frac{\text{Facility Sulfate Impact (Mm}^{-1}) \; \downarrow\uparrow}{\text{Total Impact of All Point Sources of Sulfate + Nitrate (Mm}^{-1}) \; \downarrow}$$

PSAT Reasonable Progress Screening

- Due to the amount of resources already invested in the AOI and PSAT analysis, **VISTAS does not plan to redo the original AOI or PSAT analyses**.
- In cases where emissions decreased or increased at individual facilities being considered for a four-factor analysis, the facility contributions will be adjusted to be consistent with the lower/higher facility emissions before comparing to the PSAT contribution threshold.
- **EPA verbally stated this should be okay 2/6/2020.**

Original Facility PSAT Contributions

- **Original Facility Sulfate PSAT Contributions (%)**

$$= \frac{\text{Facility Sulfate PSAT Contributions } (Mm^{-1})}{\text{Total Sulfate + Nitrate Point Contribution } (Mm^{-1})}$$

- **Original Facility Nitrate PSAT Contributions (%)**

$$= \frac{\text{Facility Nitrate PSAT Contributions } (Mm^{-1})}{\text{Total Sulfate + Nitrate Point Contribution } (Mm^{-1})}$$

Revised Facility Sulfate PSAT Results

- **Revised Facility Sulfate PSAT Results**
  = Original Facility Sulfate PSAT Results
  * SO_2 Ratio_Facility * Ratio_Class_I_Area

where, SO_2 Ratio_Facility = $\dfrac{\textit{(Revised facility } SO_2 \textit{ emissions)}}{\textit{(Original facility } SO_2 \textit{ emissions)}}$

where, Ratio_Class_I_Area = $\dfrac{\textit{(Original sulfate + nitrate point contribution)}}{\textit{(Revised sulfate + nitrate point contribution)}}$

Revised Facility Nitrate PSAT Results

- **Revised Facility Nitrate PSAT Results
  = Original Facility Nitrate PSAT Results
  * NOx Ratio_Facility * Ratio_Class_I_Area**

$$\text{where, NOx Ratio\_Facility} = \frac{(\text{Revised facility NOx emissions})}{(\text{Original facility NOx emissions})}$$

$$\text{where, Ratio\_Class\_I\_Area} = \frac{(\text{Original sulfate} + \text{nitrate point contribution})}{(\text{Revised sulfate} + \text{nitrate point contribution})}$$

Facility Ratios (AL, FL, GA)

Facility State	Facility RPO	FACILITY_ID_STD	FACILITY_NAME_STD	SO2 Ratio	NOx Ratio
AL	VISTAS	01097-949811	Akzo Nobel Chemicals Inc	1.000	1.000
AL	VISTAS	01097-1056111	Ala Power - Barry	0.499	1.000
AL	VISTAS	01129-1028711	American Midstream Chatom, LLC	0.000	0.000
AL	VISTAS	01073-1018711	DRUMMOND COMPANY, INC.	1.000	1.000
AL	VISTAS	01053-7440211	Escambia Operating Company LLC	0.199	1.000
AL	VISTAS	01053-985111	Escambia Operating Company LLC	0.010	0.000
AL	VISTAS	01103-1000011	Nucor Steel Decatur LLC	1.000	1.000
AL	VISTAS	01109-985711	Sanders Lead Co	1.000	1.000
AL	VISTAS	01097-1061611	Union Oil of California - Chunchula Gas Plant	0.000	0.000
FL	VISTAS	12123-752411	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	1.000	1.000
FL	VISTAS	12086-900111	CEMEX CONSTRUCTION MATERIALS FL. LLC.	1.000	2.856
FL	VISTAS	12017-640611	DUKE ENERGY FLORIDA, INC. (DEF)	0.493	0.421
FL	VISTAS	12086-900011	FLORIDA POWER & LIGHT (PTF)	1.000	1.000
FL	VISTAS	12033-752711	GULF POWER - Crist	0.219	0.382
FL	VISTAS	12086-3532711	HOMESTEAD CITY UTILITIES	1.000	1.000
FL	VISTAS	12031-640211	JEA	1.027	1.591
FL	VISTAS	12105-717711	MOSAIC FERTILIZER LLC	0.568	1.000
FL	VISTAS	12057-716411	MOSAIC FERTILIZER, LLC	0.595	1.057
FL	VISTAS	12105-919811	MOSAIC FERTILIZER, LLC	0.972	1.000
FL	VISTAS	12089-845811	RAYONIER PERFORMANCE FIBERS LLC	1.000	1.000
FL	VISTAS	12089-753711	ROCK TENN CP, LLC	1.000	1.000
FL	VISTAS	12005-535411	ROCKTENN CP LLC	1.000	1.000
FL	VISTAS	12129-2731711	TALLAHASSEE CITY PURDOM GENERATING STA.	1.000	1.000
FL	VISTAS	12057-538611	TAMPA ELECTRIC COMPANY (TEC)	1.000	1.000
FL	VISTAS	12086-899911	TARMAC AMERICA LLC	1.000	2.701
FL	VISTAS	12047-769711	WHITE SPRINGS AGRICULTURAL CHEMICALS,INC	0.487	0.909
GA	VISTAS	13127-3721011	Brunswick Cellulose Inc	1.000	1.000
GA	VISTAS	13015-2813011	Ga Power Company - Plant Bowen	1.000	1.000
GA	VISTAS	13103-536311	Georgia-Pacific Consumer Products LP (Savannah River Mill)	1.000	1.000
GA	VISTAS	13051-3679811	International Paper - Savannah	1.000	1.000
GA	VISTAS	13115-539311	TEMPLE INLAND	1.000	1.000

Facility Ratios (KY, MS, NC, SC, TN, VA)

Facility State	Facility RPO	FACILITY_ID_STD	FACILITY_NAME_STD	SO2 Ratio	NOx Ratio
KY	VISTAS	21183-5561611	Big Rivers Electric Corp - Wilson Station	1.000	1.000
KY	VISTAS	21091-7352411	Century Aluminum of KY LLC	0.441	1.000
KY	VISTAS	21177-5196711	Tennessee Valley Authority - Paradise Fossil Plant	0.004	0.238
KY	VISTAS	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	1.000	1.000
MS	VISTAS	28059-8384311	Chevron Products Company, Pascagoula Refinery	1.000	1.000
MS	VISTAS	28059-6251011	Mississippi Power Company, Plant Victor J Daniel	1.000	1.000
NC	VISTAS	37087-7920511	Blue Ridge Paper Products - Canton Mill	0.359	0.978
NC	VISTAS	37117-8049311	Domtar Paper Company, LLC	1.000	1.000
NC	VISTAS	37035-8370411	Duke Energy Carolinas, LLC - Marshall Steam Station	0.641	0.713
NC	VISTAS	37013-8479311	PCS Phosphate Company, Inc. - Aurora	1.000	1.000
NC	VISTAS	37023-8513011	SGL Carbon LLC	1.000	1.000
SC	VISTAS	45015-4834911	ALUMAX OF SOUTH CAROLINA	1.000	1.000
SC	VISTAS	45043-5698611	INTERNATIONAL PAPER GEORGETOWN MILL	1.000	1.000
SC	VISTAS	45019-4973611	KAPSTONE CHARLESTON KRAFT LLC	1.000	1.000
SC	VISTAS	45015-4120411	SANTEE COOPER CROSS GENERATING STATION	1.000	1.000
SC	VISTAS	45043-6652811	SANTEE COOPER WINYAH GENERATING STATION	1.000	1.000
SC	VISTAS	45015-8306711	SCE&G WILLIAMS	1.000	1.000
TN	VISTAS	47093-4979911	Cemex - Knoxville Plant	1.000	1.000
TN	VISTAS	47163-3982311	EASTMAN CHEMICAL COMPANY	1.000	1.000
TN	VISTAS	47105-4129211	TATE & LYLE, Loudon	0.352	0.261
TN	VISTAS	47001-6196011	TVA BULL RUN FOSSIL PLANT	0.000	0.000
TN	VISTAS	47161-4979311	TVA CUMBERLAND FOSSIL PLANT	1.000	1.000
TN	VISTAS	47145-4979111	TVA KINGSTON FOSSIL PLANT	0.225	0.225
VA	VISTAS	51027-4034811	Jewell Coke Company LLP	1.000	1.000
VA	VISTAS	51580-5798711	Meadwestvaco Packaging Resource Group	1.000	1.000
VA	VISTAS	51023-5039811	Roanoke Cement Company	1.000	1.000

Facility Ratios (WV, AR, MO, MD, PA, IL, IN, OH)

Facility State	Facility RPO	FACILITY_ID_STD	FACILITY_NAME_STD	SO2 Ratio	NOx Ratio
WV	VISTAS	54033-6271711	ALLEGHENY ENERGY SUPPLY CO, LLC-HARRISON	1.027	0.847
WV	VISTAS	54049-4864511	AMERICAN BITUMINOUS POWER-GRANT TOWN PLT	1.278	1.394
WV	VISTAS	54079-6789111	APPALACHIAN POWER COMPANY - JOHN E AMOS PLANT	0.555	1.495
WV	VISTAS	54023-6257011	Dominion Resources, Inc. - MOUNT STORM POWER STATION	0.449	0.487
WV	VISTAS	54041-6900311	EQUITRANS - COPLEY RUN CS 70	1.000	1.000
WV	VISTAS	54083-6790711	FILES CREEK 6C4340	1.000	1.000
WV	VISTAS	54083-6790511	GLADY 6C4350	1.000	1.000
WV	VISTAS	54093-6327811	KINGSFORD MANUFACTURING COMPANY	1.000	1.000
WV	VISTAS	54061-16320111	LONGVIEW POWER	1.010	1.437
WV	VISTAS	54051-6902311	MITCHELL PLANT	0.787	1.459
WV	VISTAS	54061-6773611	MONONGAHELA POWER CO.- FORT MARTIN POWER	0.626	0.873
WV	VISTAS	54073-4782811	MONONGAHELA POWER CO-PLEASANTS POWER STA	0.684	1.042
WV	VISTAS	54061-6773811	MORGANTOWN ENERGY ASSOCIATES	0.004	0.330
AR	CENRAP	05063-1083411	ENTERGY ARKANSAS INC-INDEPENDENCE PLANT	0.426	0.317
MO	CENRAP	29143-5363811	NEW MADRID POWER PLANT-MARSTON	0.665	0.923
MD	MANE-VU	24001-7763811	Luke Paper Company	0.436	1.000
PA	MANE-VU	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	0.370	0.773
PA	MANE-VU	42063-3005211	HOMER CITY GEN LP/ CENTER TWP	0.782	0.951
PA	MANE-VU	42063-3005111	NRG WHOLESALE GEN/SEWARD GEN STA	0.767	0.724
IL	Midwest RPO	17127-7808911	Joppa Steam	0.392	0.424
IN	Midwest RPO	18173-8183111	Alcoa Warrick Power Plt Agc Div of AL	0.288	0.271
IN	Midwest RPO	18051-7363111	Gibson	0.562	0.702
IN	Midwest RPO	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	0.353	0.962
IN	Midwest RPO	18125-7362411	INDIANAPOLIS POWER & LIGHT PETERSBURG	0.519	0.502
IN	Midwest RPO	18129-8166111	Sigeco AB Brown South Indiana Gas & Ele	0.000	0.018
OH	Midwest RPO	39081-8115711	Cardinal Power Plant (Cardinal Operating Company) (0641050002)	1.326	1.639
OH	Midwest RPO	39031-8010811	Conesville Power Plant (0616000000)	0.000	0.000
OH	Midwest RPO	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	0.467	0.820
OH	Midwest RPO	39053-8148511	General James M. Gavin Power Plant (0627010056)	0.525	0.983
OH	Midwest RPO	39053-7983011	Ohio Valley Electric Corp., Kyger Creek Station (0627000003)	1.258	0.685

Class I Area Ratios

State	Class I Area	Ratio_Class_I_Area
AL	Sipsey Wilderness Area (SIPS)	1.382
FL	Chassahowitzka Wilderness Area (CHAS)	1.325
FL	Everglades NP (EVER)	1.290
FL	St Marks Wilderness Area (SAMA)	1.363
GA	Cohutta Wilderness Area (COHU)	1.363
GA	Okefenokee Wilderness Area (OKEF)	1.317
GA	Wolf Island Wilderness (WOLF)	1.311
KY	Mammoth Cave NP (MACA)	1.337
NC	Linville Gorge Wilderness Area (LIGO)	1.411
NC	Shining Rock Wilderness Area (SHRO)	1.410
NC	Swanquarter Wilderness Area (SWAN)	1.398
SC	Cape Romain Wilderness (ROMA)	1.302
TN/NC	Great Smoky Mountains NP (GRSM)	1.394
TN/NC	Joyce Kilmer-Slickrock Wilderness (JOYC)	1.401
VA	James River Face Wilderness (JARI)	1.416
VA	Shenandoah NP (SHEN)	1.463
WV	Dolly Sods Wilderness (DOSO)	1.417
WV	Otter Creek Wilderness (OTCR)	1.412
AR	Caney Creek Wilderness Area (CACR)	1.518
AR	Upper Buffalo Wilderness Area (UPBU)	1.490
LA	Breton Wilderness (BRET)	1.306
ME	Acadia National Park (ACAD)	1.402
ME	Moosehorn Wilderness EDM (MOOS)	1.417
MI	Seney Wilderness Area (SENE)	1.262
MO	Hercules-Glades Wilderness Area (HEGL)	1.450
MO	Mingo Wilderness Area (MING)	1.360
NH	Great Gulf Wilderness Area (GRGU)	1.463
NH	Presidential Range-Dry River Wilderness (PRDR)	1.463
NJ	Brigantine Wilderness Area (BRIG)	1.391
VT	Lye Brook Wilderness (LYEB)	1.471

EXAMPLE: New Madrid Power at SIPS

- **Revised Facility Sulfate PSAT Results**
  = Original Facility Sulfate PSAT Results
  * SO_2 Ratio_Facility * Ratio_Class_I_Area

- **Original Facility Sulfate PSAT Results = 1.46%**

- **Revised Facility Sulfate PSAT Results**
  = 1.46% * 0.665 (Slide 100) * 1.382 (Slide 101)
  = 1.34% (Slide 103)

For detailed calculations, see [Handout - Roadmap](#) located at:
https://www.metro4-sesarm.org/content/vistas-regional-haze-program

Sipsey Wilderness Area (AL)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Nitrate PSAT %
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	337.7	0.364	16.370	2.22%	0.009	16.370	0.05%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	690.9	0.327	16.370	1.99%	0.021	16.370	0.13%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	398.4	0.327	16.370	1.99%	0.050	16.370	0.31%
IN	18051-7363111	Gibson	448.7	0.270	16.370	1.65%	0.029	16.370	0.18%
IN	18125-7362411	INDIANAPOLIS POWER & LIGHT PETERSBURG	464.4	0.258	16.370	1.57%	0.026	16.370	0.16%
TN	47161-4979311	TVA CUMBERLAND FOSSIL PLANT	228.9	0.242	16.370	1.48%	0.028	16.370	0.17%
MO	29143-5363811	NEW MADRID POWER PLANT-MARSTON	314.5	0.220	16.370	1.34%	0.012	16.370	0.07%
KY	21183-5561611	Big Rivers Electric Corp - Wilson Station	345.5	0.211	16.370	1.29%	0.008	16.370	0.05%

Chassahowitzka Wilderness Area (FL)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm⁻¹	FINAL Revised EGU + NEGU Mm⁻¹	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm⁻¹	FINAL Revised EGU + NEGU Mm⁻¹	FINAL Revised Nitrate PSAT %
FL	12017-640611	DUKE ENERGY FLORIDA, INC. (DEF)	27.4	0.629	10.092	6.24%	0.023	10.092	0.23%
GA	13015-2813011	Ga Power Company - Plant Bowen	637.2	0.230	10.092	2.28%	0.003	10.092	0.03%
FL	12057-538611	TAMPA ELECTRIC COMPANY (TEC)	106.8	0.129	10.092	1.28%	0.007	10.092	0.07%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	1,098.0	0.102	10.092	1.01%	0.005	10.092	0.05%
AL	01109-985711	Sanders Lead Co	471.2	0.101	10.092	1.00%	0.001	10.092	0.01%

Everglades NP (FL)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Nitrate PSAT %
FL	12057-538611	TAMPA ELECTRIC COMPANY (TEC)	316.6	0.044	1.333	3.30%	0.000	1.333	0.00%
FL	12105-919811	MOSAIC FERTILIZER, LLC	304.7	0.035	1.333	2.62%	0.000	1.333	0.00%
FL	12105-717711	MOSAIC FERTILIZER LLC	303.3	0.035	1.333	2.60%	0.000	1.333	0.00%
FL	12086-899911	TARMAC AMERICA LLC	61.7	0.003	1.333	0.23%	0.035	1.333	2.63%

St Marks Wilderness Area (FL)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Nitrate PSAT %
GA	13015-2813011	Ga Power Company - Plant Bowen	452.9	0.574	11.729	4.89%	0.004	11.729	0.03%
FL	12005-535411	ROCKTENN CP LLC	140.8	0.540	11.729	4.60%	0.015	11.729	0.13%
AL	01109-985711	Sanders Lead Co	255.9	0.131	11.729	1.12%	0.000	11.729	0.00%

Cohutta Wilderness Area (GA)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Nitrate PSAT %
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	512.0	0.322	13.229	2.44%	0.009	13.229	0.07%
GA	13015-2813011	Ga Power Company - Plant Bowen	78.0	0.282	13.229	2.13%	0.005	13.229	0.04%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	457.2	0.190	13.229	1.44%	0.002	13.229	0.02%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	410.1	0.181	13.229	1.37%	0.005	13.229	0.04%
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	454.6	0.173	13.229	1.31%	0.005	13.229	0.04%
TN	47163-3982311	EASTMAN CHEMICAL COMPANY	269.8	0.165	13.229	1.25%	0.012	13.229	0.09%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	801.1	0.137	13.229	1.04%	0.002	13.229	0.01%
IN	18051-7363111	Gibson	487.1	0.137	13.229	1.03%	0.002	13.229	0.02%

Okefenokee Wilderness Area (GA)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Nitrate PSAT %
FL	12047-769711	WHITE SPRINGS AGRICULTURAL CHEMICALS,INC	71.5	0.372	13.400	2.77%	0.002	13.400	0.01%
GA	13015-2813011	Ga Power Company - Plant Bowen	458.1	0.308	13.400	2.30%	0.007	13.400	0.05%
FL	12123-752411	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	153.5	0.289	13.400	2.16%	0.019	13.400	0.14%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	909.1	0.203	13.400	1.51%	0.002	13.400	0.01%
FL	12089-753711	ROCK TENN CP, LLC	64.8	0.176	13.400	1.31%	0.020	13.400	0.15%
SC	45015-4120411	SANTEE COOPER CROSS GENERATING STATION	348.1	0.158	13.400	1.18%	0.006	13.400	0.04%
GA	13051-3679811	International Paper - Savannah	178.9	0.140	13.400	1.04%	0.008	13.400	0.06%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	939.4	0.138	13.400	1.03%	0.006	13.400	0.04%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	1,129.0	0.137	13.400	1.02%	0.002	13.400	0.01%

Wolf Island Wilderness (GA)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Nitrate PSAT %
FL	12089-753711	ROCK TENN CP, LLC	74.9	0.304	12.957	2.35%	0.018	12.957	0.14%
GA	13015-2813011	Ga Power Company - Plant Bowen	458.1	0.302	12.957	2.33%	0.007	12.957	0.05%
GA	13127-3721011	Brunswick Cellulose Inc	27.9	0.228	12.957	1.76%	0.017	12.957	0.13%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	845.3	0.224	12.957	1.73%	0.003	12.957	0.02%
GA	13051-3679811	International Paper - Savannah	85.9	0.200	12.957	1.54%	0.012	12.957	0.09%
SC	45015-4120411	SANTEE COOPER CROSS GENERATING STATION	251.0	0.168	12.957	1.30%	0.011	12.957	0.08%
FL	12031-640211	JEA	105.1	0.167	12.957	1.29%	0.008	12.957	0.06%
SC	45015-4834911	ALUMAX OF SOUTH CAROLINA	223.0	0.162	12.957	1.25%	0.001	12.957	0.01%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	1,048.6	0.149	12.957	1.15%	0.002	12.957	0.01%

Mammoth Cave NP (KY)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm⁻¹	FINAL Revised EGU + NEGU Mm⁻¹	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm⁻¹	FINAL Revised EGU + NEGU Mm⁻¹	FINAL Revised Nitrate PSAT %
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	118.0	0.426	25.289	1.68%	0.085	25.289	0.33%
IN	18051-7363111	Gibson	198.2	0.411	25.289	1.63%	0.084	25.289	0.33%
KY	21183-5561611	Big Rivers Electric Corp - Wilson Station	89.9	0.361	25.289	1.43%	0.020	25.289	0.08%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	233.6	0.290	25.289	1.15%	0.049	25.289	0.19%
MO	29143-5363811	NEW MADRID POWER PLANT-MARSTON	312.7	0.289	25.289	1.14%	0.022	25.289	0.09%
IN	18125-7362411	INDIANAPOLIS POWER & LIGHT PETERSBURG	182.9	0.264	25.289	1.04%	0.068	25.289	0.27%

Linville Gorge Wilderness Area (NC)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Nitrate PSAT %
TN	47163-3982311	EASTMAN CHEMICAL COMPANY	81.9	0.522	12.884	4.05%	0.013	12.884	0.10%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	329.2	0.446	12.884	3.46%	0.002	12.884	0.02%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	567.5	0.235	12.884	1.82%	0.000	12.884	0.00%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	626.3	0.172	12.884	1.34%	0.002	12.884	0.02%
TN	47161-4979311	TVA CUMBERLAND FOSSIL PLANT	516.6	0.154	12.884	1.20%	0.001	12.884	0.01%
GA	13015-2813011	Ga Power Company - Plant Bowen	340.9	0.146	12.884	1.13%	0.000	12.884	0.00%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	503.5	0.142	12.884	1.10%	0.012	12.884	0.09%
IN	18051-7363111	Gibson	582.3	0.138	12.884	1.07%	0.008	12.884	0.07%
MO	29143-5363811	NEW MADRID POWER PLANT-MARSTON	688.6	0.134	12.884	1.04%	0.000	12.884	0.00%
VA	51027-4034811	Jewell Coke Company LLP	140.4	0.132	12.884	1.02%	0.000	12.884	0.00%

Shining Rock Wilderness Area (NC)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Nitrate PSAT %
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	397.3	0.297	12.313	2.41%	0.001	12.313	0.01%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	573.4	0.201	12.313	1.63%	0.003	12.313	0.02%
TN	47161-4979311	TVA CUMBERLAND FOSSIL PLANT	454.1	0.162	12.313	1.32%	0.002	12.313	0.02%
GA	13015-2813011	Ga Power Company - Plant Bowen	241.6	0.159	12.313	1.29%	0.001	12.313	0.01%
MO	29143-5363811	NEW MADRID POWER PLANT-MARSTON	625.2	0.158	12.313	1.28%	0.001	12.313	0.01%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	473.3	0.156	12.313	1.27%	0.012	12.313	0.09%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	657.6	0.151	12.313	1.23%	0.000	12.313	0.00%
IN	18051-7363111	Gibson	554.2	0.151	12.313	1.23%	0.008	12.313	0.07%
NC	37087-7920511	Blue Ridge Paper Products - Canton Mill	16.9	0.133	12.313	1.08%	0.012	12.313	0.10%
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	406.7	0.129	12.313	1.05%	0.002	12.313	0.01%
AR	05063-1083411	ENTERGY ARKANSAS INC-INDEPENDENCE PLANT	783.3	0.129	12.313	1.04%	0.001	12.313	0.01%
TN	47163-3982311	EASTMAN CHEMICAL COMPANY	126.9	0.128	12.313	1.04%	0.003	12.313	0.02%

Swanquarter Wilderness Area (NC)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Nitrate PSAT %
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	640.2	0.375	10.894	3.44%	0.009	10.894	0.09%
NC	37013-8479311	PCS Phosphate Company, Inc. - Aurora	52.5	0.329	10.894	3.02%	0.007	10.894	0.06%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	651.5	0.219	10.894	2.01%	0.005	10.894	0.05%
OH	39081-8115711	Cardinal Power Plant (Cardinal Operating Company) (0641050002)	659.6	0.203	10.894	1.86%	0.007	10.894	0.06%
MD	24001-7763811	Luke Paper Company	512.5	0.191	10.894	1.75%	0.008	10.894	0.07%
WV	54033-6271711	ALLEGHENY ENERGY SUPPLY CO, LLC-HARRISON	568.6	0.186	10.894	1.71%	0.013	10.894	0.12%
PA	42063-3005211	HOMER CITY GEN LP/ CENTER TWP	620.1	0.151	10.894	1.38%	0.008	10.894	0.07%
WV	54073-4782811	MONONGAHELA POWER CO-PLEASANTS POWER STA	625.7	0.127	10.894	1.17%	0.005	10.894	0.05%
GA	13015-2813011	Ga Power Company - Plant Bowen	810.6	0.112	10.894	1.03%	0.003	10.894	0.03%
NC	37117-8049311	Domtar Paper Company, LLC	69.0	0.109	10.894	1.00%	0.022	10.894	0.20%

Cape Romain Wilderness Area (SC)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Nitrate PSAT %
SC	45019-4973611	KAPSTONE CHARLESTON KRAFT LLC	29.3	0.523	14.028	3.73%	0.046	14.028	0.33%
GA	13015-2813011	Ga Power Company - Plant Bowen	506.2	0.495	14.028	3.53%	0.019	14.028	0.14%
SC	45015-4834911	ALUMAX OF SOUTH CAROLINA	39.1	0.327	14.028	2.33%	0.003	14.028	0.02%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	857.1	0.320	14.028	2.28%	0.002	14.028	0.01%
SC	45015-4120411	SANTEE COOPER CROSS GENERATING STATION	63.8	0.316	14.028	2.25%	0.038	14.028	0.27%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	701.0	0.305	14.028	2.17%	0.005	14.028	0.04%
SC	45043-5698611	INTERNATIONAL PAPER GEORGETOWN MILL	57.4	0.230	14.028	1.64%	0.021	14.028	0.15%
SC	45043-6652811	SANTEE COOPER WINYAH GENERATING STATION	51.4	0.187	14.028	1.33%	0.024	14.028	0.17%
GA	13051-3679811	International Paper - Savannah	166.1	0.180	14.028	1.28%	0.009	14.028	0.06%

Great Smoky Mountains National Park (TN/NC)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Nitrate PSAT %
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	400.5	0.520	13.916	3.73%	0.003	13.916	0.02%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	465.3	0.183	13.916	1.32%	0.011	13.916	0.08%
TN	47163-3982311	EASTMAN CHEMICAL COMPANY	160.1	0.170	13.916	1.22%	0.007	13.916	0.05%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	688.2	0.166	13.916	1.19%	0.001	13.916	0.01%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	375.5	0.166	13.916	1.19%	0.035	13.916	0.25%
IN	18051-7363111	Gibson	456.3	0.146	13.916	1.05%	0.037	13.916	0.27%

Joyce Kilmer-Slickrock Wilderness Area (TN/NC)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Nitrate PSAT %
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	425.1	0.473	13.694	3.45%	0.002	13.694	0.01%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	472.8	0.189	13.694	1.38%	0.014	13.694	0.10%
TN	47163-3982311	EASTMAN CHEMICAL COMPANY	179.2	0.178	13.694	1.30%	0.003	13.694	0.02%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	711.0	0.154	13.694	1.12%	0.000	13.694	0.00%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	391.2	0.154	13.694	1.12%	0.030	13.694	0.22%
GA	13015-2813011	Ga Power Company - Plant Bowen	166.2	0.152	13.694	1.11%	0.001	13.694	0.01%
IN	18051-7363111	Gibson	471.7	0.139	13.694	1.02%	0.029	13.694	0.21%
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	385.1	0.137	13.694	1.00%	0.002	13.694	0.01%

James River Face Wilderness Area (VA)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Nitrate PSAT %
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	270.2	0.582	14.404	4.04%	0.016	14.404	0.11%
WV	54033-6271711	ALLEGHENY ENERGY SUPPLY CO, LLC-HARRISON	207.6	0.526	14.404	3.65%	0.020	14.404	0.14%
OH	39081-8115711	Cardinal Power Plant (Cardinal Operating Company) (0641050002)	306.4	0.520	14.404	3.61%	0.008	14.404	0.06%
WV	54073-4782811	MONONGAHELA POWER CO-PLEASANTS POWER STA	248.0	0.325	14.404	2.26%	0.007	14.404	0.05%
WV	54079-6789111	APPALACHIAN POWER COMPANY - JOHN E AMOS PLANT	223.5	0.278	14.404	1.93%	0.016	14.404	0.11%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	337.1	0.217	14.404	1.51%	0.005	14.404	0.04%
VA	51580-5798711	Meadwestvaco Packaging Resource Group	46.5	0.209	14.404	1.45%	0.031	14.404	0.22%
OH	39053-7983011	Ohio Valley Electric Corp., Kyger Creek Station (0627000003)	270.0	0.170	14.404	1.18%	0.006	14.404	0.04%
WV	54051-6902311	MITCHELL PLANT	269.6	0.156	14.404	1.08%	0.006	14.404	0.04%

Shenandoah National Park (VA)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Nitrate PSAT %
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	249.8	0.740	15.375	4.81%	0.009	15.375	0.06%
OH	39081-8115711	Cardinal Power Plant (Cardinal Operating Company) (0641050002)	269.6	0.692	15.375	4.50%	0.018	15.375	0.12%
WV	54033-6271711	ALLEGHENY ENERGY SUPPLY CO, LLC-HARRISON	189.7	0.636	15.375	4.14%	0.070	15.375	0.46%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	323.4	0.576	15.375	3.75%	0.022	15.375	0.14%
WV	54073-4782811	MONONGAHELA POWER CO-PLEASANTS POWER STA	265.0	0.339	15.375	2.20%	0.043	15.375	0.28%
PA	42063-3005211	HOMER CITY GEN LP/ CENTER TWP	230.4	0.274	15.375	1.78%	0.010	15.375	0.06%
MD	24001-7763811	Luke Paper Company	118.4	0.216	15.375	1.41%	0.021	15.375	0.14%
PA	42063-3005111	NRG WHOLESALE GEN/SEWARD GEN STA	215.5	0.172	15.375	1.12%	0.003	15.375	0.02%
WV	54051-6902311	MITCHELL PLANT	251.8	0.155	15.375	1.01%	0.025	15.375	0.16%
OH	39053-7983011	Ohio Valley Electric Corp., Kyger Creek Station (0627000003)	324.1	0.155	15.375	1.01%	0.009	15.375	0.06%

Dolly Sods Wilderness Area (WV)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm^{-1}	FINAL Revised EGU + NEGU Mm^{-1}	FINAL Revised Nitrate PSAT %
WV	54033-6271711	ALLEGHENY ENERGY SUPPLY CO, LLC-HARRISON	83.6	1.390	19.349	7.18%	0.059	19.349	0.31%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	233.8	0.945	19.349	4.88%	0.009	19.349	0.05%
WV	54073-4782811	MONONGAHELA POWER CO-PLEASANTS POWER STA	163.9	0.810	19.349	4.19%	0.020	19.349	0.10%
OH	39081-8115711	Cardinal Power Plant (Cardinal Operating Company) (0641050002)	163.9	0.778	19.349	4.02%	0.007	19.349	0.03%
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	416.9	0.288	19.349	1.49%	0.010	19.349	0.05%
WV	54051-6902311	MITCHELL PLANT	144.2	0.276	19.349	1.42%	0.009	19.349	0.05%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	172.8	0.246	19.349	1.27%	0.001	19.349	0.00%
OH	39053-7983011	Ohio Valley Electric Corp., Kyger Creek Station (0627000003)	234.9	0.229	19.349	1.18%	0.003	19.349	0.02%
WV	54079-6789111	APPALACHIAN POWER COMPANY - JOHN E AMOS PLANT	219.8	0.221	19.349	1.14%	0.006	19.349	0.03%
WV	54061-6773611	MONONGAHELA POWER CO.- FORT MARTIN POWER	79.8	0.218	19.349	1.13%	0.044	19.349	0.23%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	847.6	0.204	19.349	1.05%	0.003	19.349	0.02%

Otter Creek Wilderness Area (WV)

State	Facility ID	Facility Name	DISTANCE_km	FINAL Revised Sulfate PSAT Mm⁻¹	FINAL Revised EGU + NEGU Mm⁻¹	FINAL Revised Sulfate PSAT %	FINAL Revised Nitrate PSAT Mm⁻¹	FINAL Revised EGU + NEGU Mm⁻¹	FINAL Revised Nitrate PSAT %
WV	54033-6271711	ALLEGHENY ENERGY SUPPLY CO, LLC-HARRISON	72.8	1.242	19.077	6.51%	0.059	19.077	0.31%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	214.2	1.001	19.077	5.25%	0.011	19.077	0.06%
WV	54073-4782811	MONONGAHELA POWER CO-PLEASANTS POWER STA	148.3	0.809	19.077	4.24%	0.023	19.077	0.12%
OH	39081-8115711	Cardinal Power Plant (Cardinal Operating Company) (0641050002)	162.7	0.727	19.077	3.81%	0.008	19.077	0.04%
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	397.5	0.302	19.077	1.58%	0.012	19.077	0.06%
WV	54051-6902311	MITCHELL PLANT	136.8	0.297	19.077	1.56%	0.010	19.077	0.05%
WV	54079-6789111	APPALACHIAN POWER COMPANY - JOHN E AMOS PLANT	198.0	0.249	19.077	1.31%	0.007	19.077	0.04%
OH	39053-7983011	Ohio Valley Electric Corp., Kyger Creek Station (0627000003)	215.3	0.242	19.077	1.27%	0.004	19.077	0.02%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	826.5	0.207	19.077	1.09%	0.003	19.077	0.02%
IN	18051-7363111	Gibson	709.7	0.193	19.077	1.01%	0.009	19.077	0.05%
WV	54061-6773611	MONONGAHELA POWER CO.- FORT MARTIN POWER	82.7	0.192	19.077	1.00%	0.046	19.077	0.24%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	655.7	0.191	19.077	1.00%	0.007	19.077	0.04%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	186.5	0.190	19.077	1.00%	0.001	19.077	0.00%

Non-VISTAS Class I Areas

- Only two VISTAS facilities have a contribution ≥ 1.00% at any non-VISTAS Class I Area
- **ALLEGHENY ENERGY SUPPLY CO, LLC-HARRISON (WV)**
  - Moosehorn Wilderness EDM (1.06% sulfate)
- **Tennessee Valley Authority (TVA) - Shawnee Fossil Plant (KY)**
  - Caney Creek Wilderness Area (1.09% sulfate)
  - Hercules-Glades Wilderness Area (1.95% sulfate)
  - Mingo Wilderness Area (1.47% sulfate)
  - Great Gulf Wilderness Area (1.03% sulfate)
  - Presidential Range-Dry River Wilderness (1.03% sulfate)

VISTAS Facilities ≥ 1.00%

State	FACILITY_ID_STD	FACILITY_NAME_STD	IMPACTED CLASS I AREAS
AL	01109-985711	Sanders Lead Co	CHAS, SAMA
FL	12123-752411	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	OKEF
FL	12017-640611	DUKE ENERGY FLORIDA, INC. (DEF)	CHAS
FL	12031-640211	JEA	WOLF
FL	12105-717711	MOSAIC FERTILIZER LLC	EVER
FL	12105-919811	MOSAIC FERTILIZER, LLC	EVER
FL	12089-753711	ROCK TENN CP, LLC	OKEF, WOLF
FL	12005-535411	ROCKTENN CP LLC	SAMA
FL	12057-538611	TAMPA ELECTRIC COMPANY (TEC)	CHAS, EVER
FL	12086-899911	TARMAC AMERICA LLC	EVER
FL	12047-769711	WHITE SPRINGS AGRICULTURAL CHEMICALS,INC	OKEF
GA	13127-3721011	Brunswick Cellulose Inc	WOLF
GA	13015-2813011	Ga Power Company - Plant Bowen	CHAS, COHU, JOYC, LIGO, OKEF, ROMA, SAMA, SHRO, SWAN, WOLF
GA	13051-3679811	International Paper - Savannah	OKEF, ROMA, WOLF
KY	21183-5561611	Big Rivers Electric Corp - Wilson Station	MACA, SIPS
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	CACR, CHAS, COHU, DOSO, GRGU, GRSM, HEGL, JOYC, LIGO, MACA, MING, OKEF, OTCR, PRDR, SHRO, SIPS
NC	37087-7920511	Blue Ridge Paper Products - Canton Mill	SHRO
NC	37117-8049311	Domtar Paper Company, LLC	SWAN
NC	37013-8479311	PCS Phosphate Company, Inc. - Aurora	SWAN
SC	45015-4834911	ALUMAX OF SOUTH CAROLINA	ROMA, WOLF
SC	45043-5698611	INTERNATIONAL PAPER GEORGETOWN MILL	ROMA
SC	45019-4973611	KAPSTONE CHARLESTON KRAFT LLC	ROMA
SC	45015-4120411	SANTEE COOPER CROSS GENERATING STATION	OKEF, ROMA, WOLF
SC	45043-6652811	SANTEE COOPER WINYAH GENERATING STATION	ROMA
TN	47163-3982311	EASTMAN CHEMICAL COMPANY	COHU, GRSM, JOYC, LIGO, SHRO
TN	47161-4979311	TVA CUMBERLAND FOSSIL PLANT	LIGO, SHRO, SIPS
VA	51027-4034811	Jewell Coke Company LLP	LIGO
VA	51580-5798711	Meadwestvaco Packaging Resource Group	JARI
WV	54033-6271711	ALLEGHENY ENERGY SUPPLY CO, LLC-HARRISON	DOSO, JARI, MOOS, OTCR, SHEN, SWAN
WV	54079-6789111	APPALACHIAN POWER COMPANY - JOHN E AMOS PLANT	DOSO, JARI, OTCR
WV	54051-6902311	MITCHELL PLANT	DOSO, JARI, OTCR, SHEN
WV	54061-6773611	MONONGAHELA POWER CO.- FORT MARTIN POWER	DOSO, OTCR
WV	54073-4782811	MONONGAHELA POWER CO-PLEASANTS POWER STA	DOSO, JARI, OTCR, SHEN, SWAN

Non-VISTAS Facilities ≥ 1.00%

State	FACILITY_ID_STD	FACILITY_NAME_STD	IMPACTED CLASS I AREAS
AR	05063-1083411	ENTERGY ARKANSAS INC-INDEPENDENCE PLANT	SHRO
IN	18051-7363111	Gibson	COHU, GRSM, JOYC, LIGO, MACA, OTCR, SHRO, SIPS
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	COHU, GRSM, JOYC, LIGO, MACA, OTCR, SHRO, SIPS
IN	18125-7362411	INDIANAPOLIS POWER & LIGHT PETERSBURG	MACA, SIPS
MD	24001-7763811	Luke Paper Company	SHEN, SWAN
MO	29143-5363811	NEW MADRID POWER PLANT-MARSTON	LIGO, MACA, SHRO, SIPS
OH	39081-8115711	Cardinal Power Plant (Cardinal Operating Company) (0641050002)	DOSO, JARI, OTCR, SHEN, SWAN
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	COHU, DOSO, JOYC, OTCR, SHRO
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	COHU, DOSO, GRSM, JARI, JOYC, LIGO, OKEF, OTCR, ROMA, SHEN, SHRO, SIPS, SWAN, WOLF
OH	39053-7983011	Ohio Valley Electric Corp., Kyger Creek Station (0627000003)	DOSO, JARI, OTCR, SHEN
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	COHU, DOSO, GRSM, JARI, JOYC, LIGO, OKEF, OTCR, ROMA, SHEN, SHRO, SWAN, WOLF
PA	42063-3005211	HOMER CITY GEN LP/ CENTER TWP	SHEN, SWAN
PA	42063-3005111	NRG WHOLESALE GEN/SEWARD GEN STA	SHEN

EPA Guidance (August 20, 2019)

- Many facilities already have effective emission control technologies in place. States will consider control options for these facilities on a case-by-case basis.

  - "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."

  - "For the purposes of SO_2 and NOx control measures, a combustion source (e.g., an EGU or industrial boiler or process heater) that, during the first implementation period, installed a FGD system that operates year-round with an effectiveness of at least 90 percent or by the installation of a selective catalytic reduction system that operates year-round with an overall effectiveness of at least 90 percent (in both cases calculating the effectiveness as the total for the system, including any bypassed flue gas), on a pollutant-specific basis."

Additional Considerations

- The final list of four-factor analysis sources will be determined in consultation with the FLMs, EPA, other states, and stakeholders.

- Some VISTAS states may perform additional four-factor analyses for sources not listed on Slide 122.

- States will verify projected SO_2 and NOx emissions with facilities. PSAT results can be adjusted to match.

- Some states may allow their facilities to take a permit limit that will result in adjusted PSAT impacts below the 1.00% threshold in lieu of performing a four-factor analysis.

- The large number of coal-fired EGU retirements and fuel switching from coal to natural gas need to be considered along with the sources selected for the four-factor analysis. States should not be penalized for early action.

Next Steps and Schedule

Remaining VISTAS Work Schedule

| Task	Schedule
2028 Point Emissions Updates	Completed *
2028 Emissions Processing	Completed *
2028 CAMx Modeling	Completed *
2028 Visibility Projections	Completed *
2028 Deposition Projections	Late May/Early June 2020 *
Final Reports and Documentation	Late July 2020
Website Updates and Postings	Late July 2020
End of Contract	September 30, 2020
Regional Haze SIPs Due to EPA	**July 31, 2021**
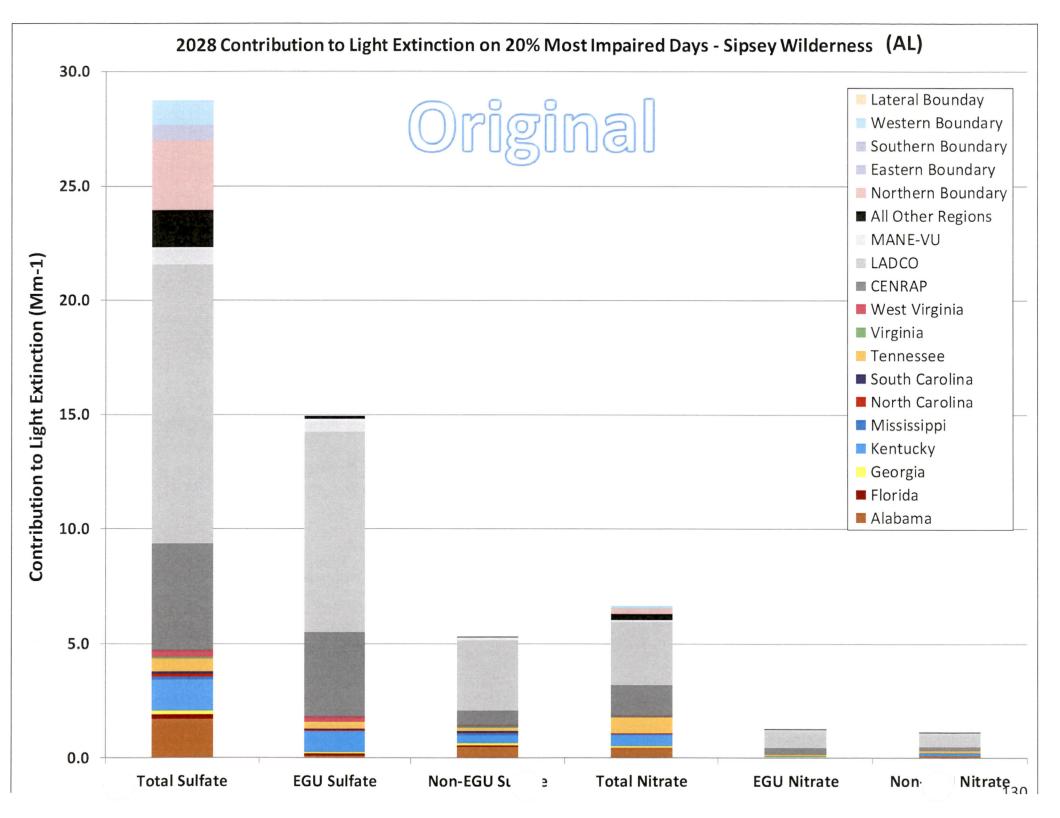
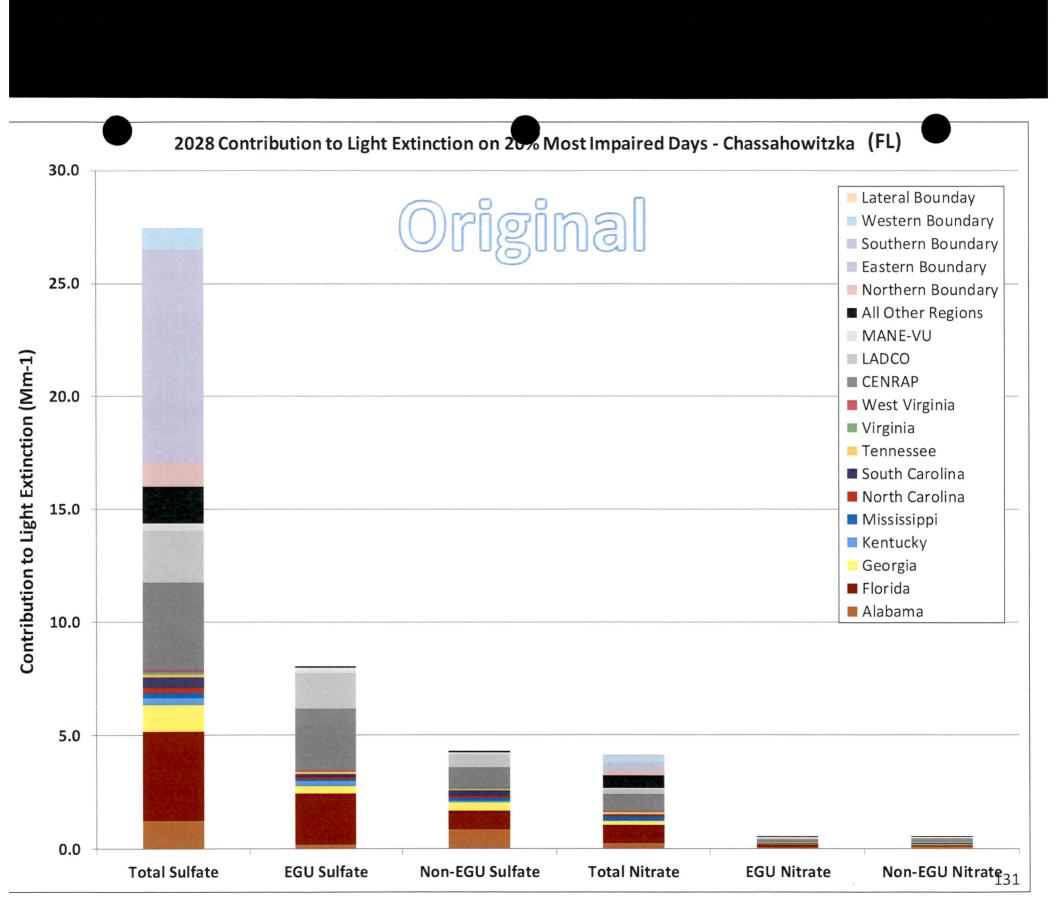** References technical work completion. Draft reports to follow.*
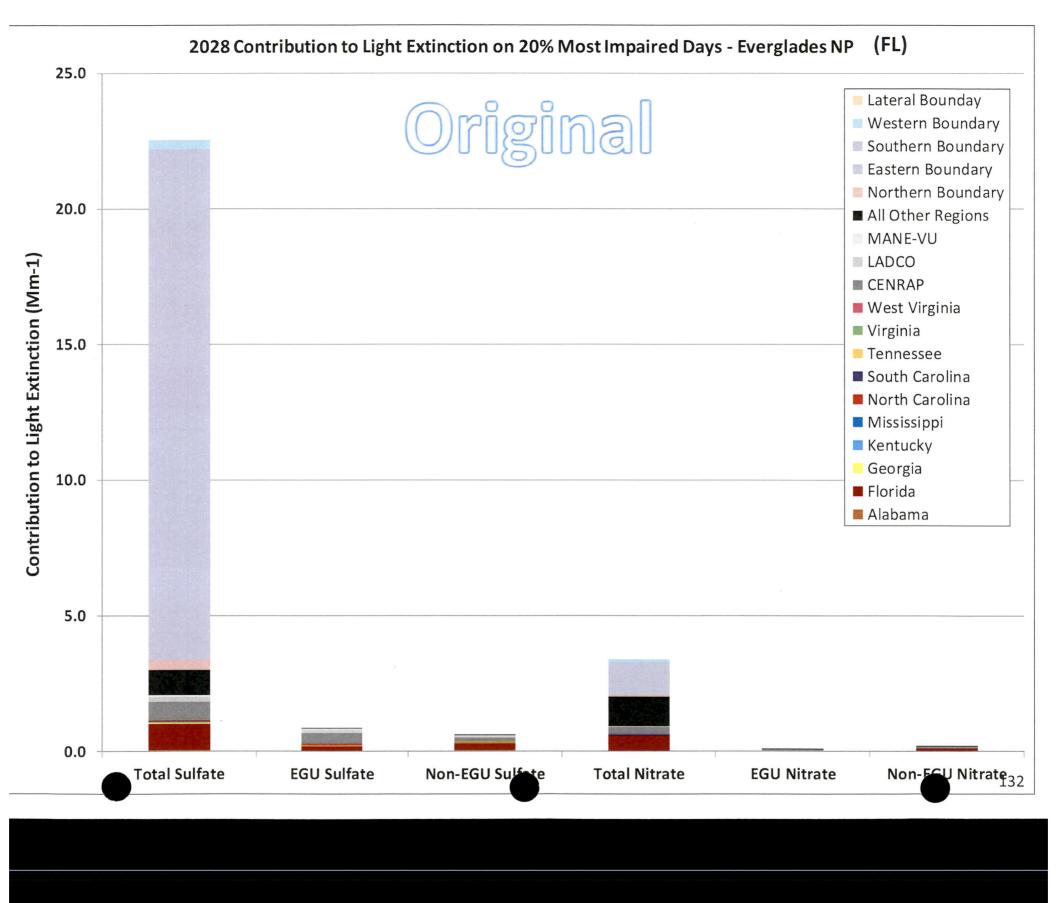
Contacts for Further Information

- For general, technical, and SIP-related questions, contact the TAWG and CC Chairs:
  - TAWG – Randy Strait (randy.strait@ncdenr.gov)
  - CC – Jim Boylan (james.boylan@dnr.ga.gov)

- For project and contract management questions, contact the Project Manager:
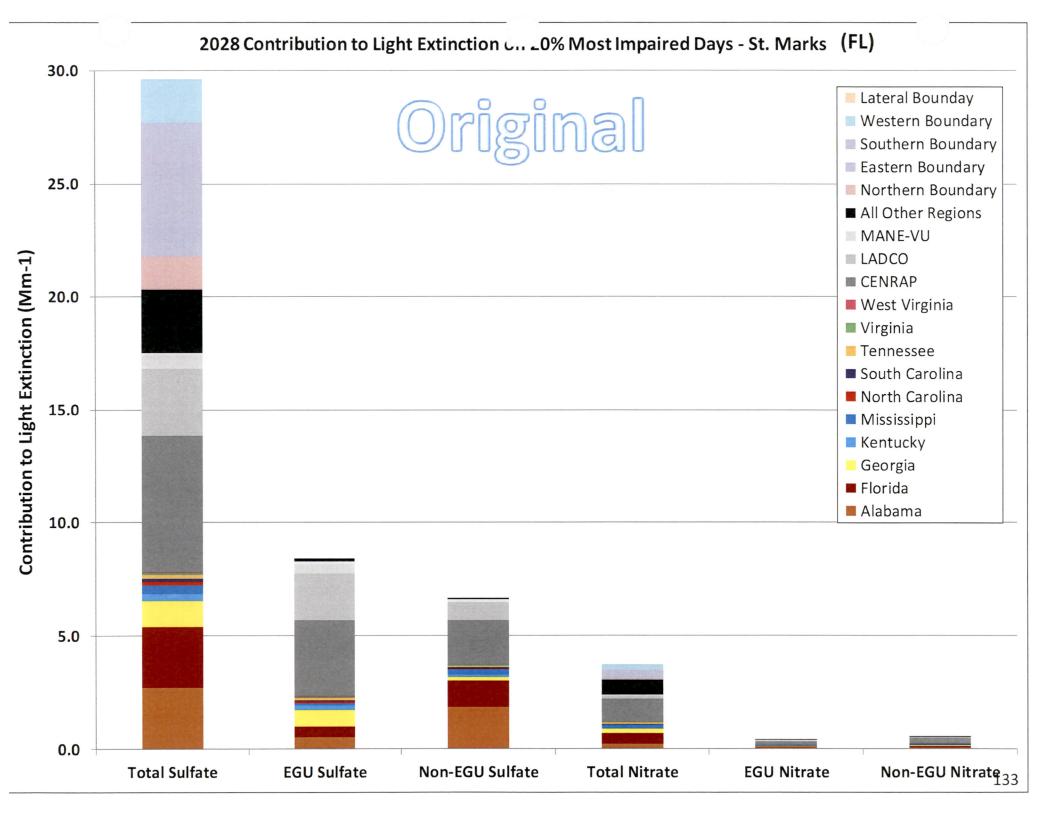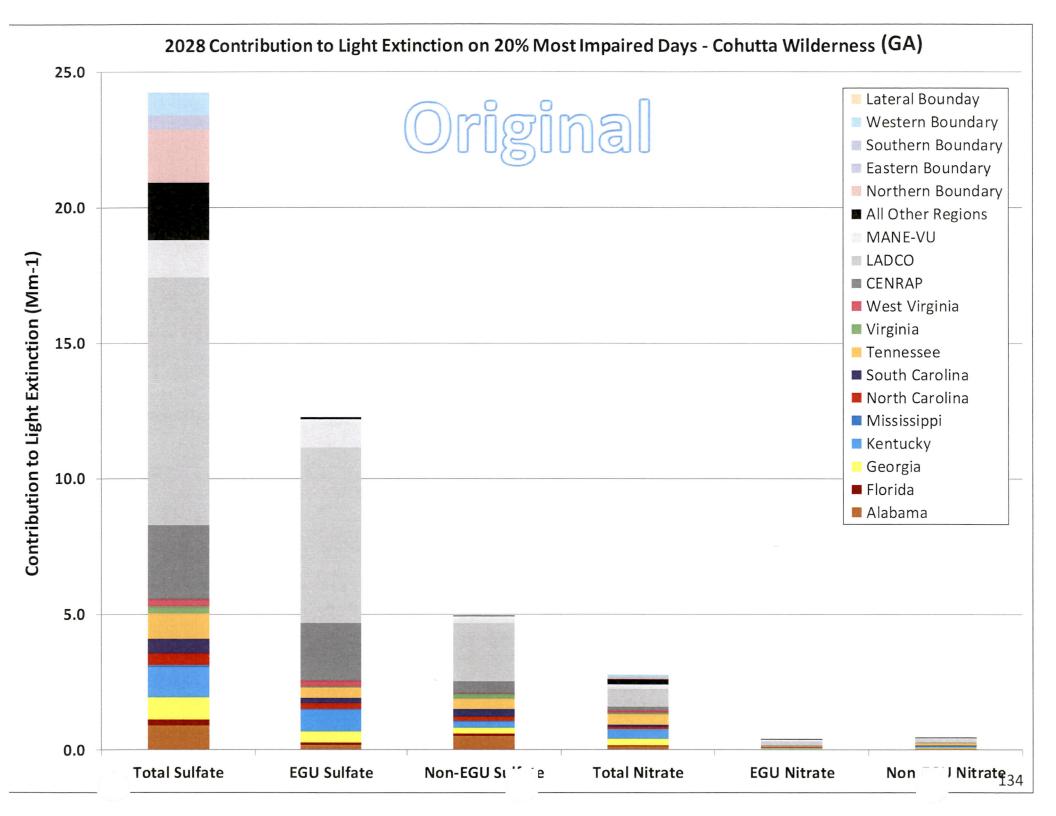 - John Hornback (hornback@metro4-sesarm.org)

Appendix:
Original Analysis
(Conducted 2018-2019)

2028 Contribution to Light Extinction on 20% Most Impaired Days - Sipsey Wilderness (AL)

2028 Contribution to Light Extinction on 20% Most Impaired Days - Chassahowitzka (FL)

Original

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

2028 Contribution to Light Extinction on 20% Most Impaired Days - Everglades NP (FL)

Original

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1), scale 0.0 to 25.0

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

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2028 Contribution to Light Extinction on 20% Most Impaired Days - St. Marks (FL)

2028 Contribution to Light Extinction on 20% Most Impaired Days - Cohutta Wilderness (GA)

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

Original

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2028 Contribution to Light Extinction on % Most Impaired Days - Okefenokee (GA)

2028 Contribution to Light Extinction on 20% Most Impaired Days - Wolf Island (GA)

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

Original

2028 Contribution to Light Extinction on 20% Most Impaired Days - Mammoth Cave NP (KY)

Original

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

2028 Contribution to Light Extinction on 20% Most Impaired Days - Linville Gorge Wilderness (NC)

138

2028 Contribution to Light Extinction on 20% [Wor]st Impaired Days - Shining Rock Wilderness (NC)

Original

2028 Contribution to Light Extinction on 20% Most Impaired Days - Swanquarter (NC)

Legend:
- Lateral Boundary
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

2028 Contribution to Light Extinction on 20% Most Impaired Days - Cape Romain (SC)

2028 Contribution to Light Extinction on 20% Most Impaired Days - Great Smoky Mountains NP (TN/NC)

Original

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

142

2028 Contribution to Light Extinction on 20% Most Impaired Days - Joyce-Kilmer-Slickrock (TN, NC) Wilderness

Original

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

2028 Contribution to Light Extinction on 20% Most Impaired Days - James River Face Wilderness (VA)

Original

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1), scale 0.0 to 30.0

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

2028 Contribution to Light Extinction on [ ] Most Impaired Days - Shenandoah NP (VA)

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1), scale 0.0 to 30.0

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

Original

145

2028 Contribution to Light Extinction on 20% Most Impaired Days - Dolly Sods Wilderness (WV)

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

Original

146

2028 Contribution to Light Extinction on 20% ...est Impaired Days - Otter Creek Wilderness (W.,

Original

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1), from 0.0 to 35.0

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

2028 Contribution to Light Extinction on 20% Most Impaired Days - Breton (LA)

2028 Contribution to Light Extinction on 20% Most Impaired Days - Caney Creek Wilderness (AR)

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

2028 Contribution to Light Extinction on 20% Most Impaired Days - Upper Buffalo Wilderness (AR)

Original

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

2028 Contribution to Light Extinction on 20% Most Impaired Days - Hercules-Glades Wilderness (HEGL)

Legend:
- Lateral Boundary
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

Original

151

2028 Contribution to Light Extinction on 20% Most Impaired Days - Mingo (MO)

Original

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1)

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

152

2028 Contribution to Light Extinction c.. _0% Most Impaired Days - Brigantine (NJ)

Original

Legend:
- Lateral Bounday
- Western Boundary
- Southern Boundary
- Eastern Boundary
- Northern Boundary
- All Other Regions
- MANE-VU
- LADCO
- CENRAP
- West Virginia
- Virginia
- Tennessee
- South Carolina
- North Carolina
- Mississippi
- Kentucky
- Georgia
- Florida
- Alabama

Y-axis: Contribution to Light Extinction (Mm-1), scale 0.0 to 30.0

X-axis categories: Total Sulfate, EGU Sulfate, Non-EGU Sulfate, Total Nitrate, EGU Nitrate, Non-EGU Nitrate

Uniform Rate of Progress Glide Path
Sipsey - 20% Most Impaired Data Days

154

Uniform Rate of Progress Glide Path
Chassahowitzka - 20% Most Impaired Data Days

Uniform Rate of Progress Glide Path
Everglades - 20% Most Impaired Data Days

Original

Haziness Index (Deciviews) vs Year

Data point labels: 19.54, 18.60, 16.92, 15.06, 15.57, 13.19, 11.33, 9.46, 8.34

Legend:
- Glide Path
- Natural Condition (Most Impaired)
- Observation (Most Impaired)
- Model Projection (Most Impaired)
- Rolling Average (Most Impaired)

156

Uniform Rate of Progress Glide Path
Saint Marks - 20% Most Impaired Data Days

Original

Haziness Index (Deciviews)

24.60
23.32
21.00
18.44
17.22
15.87
13.30
10.73
9.19

Year

Glide Path — Natural Condition (Most Impaired)
Observation (Most Impaired) — Model Projection (Most Impaired)
Rolling Average (Most Impaired)

157

Uniform Rate of Progress Glide Path
Cohutta - 20% Most Impaired Data Days

Original

Haziness Index (Deciviews) vs Year

- 29.12
- 27.49
- 24.55
- 21.28
- 18.01
- 15.95
- 14.75
- 11.48
- 9.52

Legend:
- —△— Glide Path
- ◆ Observation (Most Impaired)
- —— Rolling Average (Most Impaired)
- —— Natural Condition (Most Impaired)
- —△— Model Projection (Most Impaired)

158

Uniform Rate of Progress Glide Path Okefenokee - 20% Most Impaired Data Days

Legend:
- Glide Path
- Natural Condition (Most Impaired)
- Observation (Most Impaired)
- Model Projection (Most Impaired)
- Rolling Average (Most Impaired)

Glide Path values: 25.34, 24.02, 21.64, 18.99, 16.35, 13.70, 11.06, 9.47

Model Projection: 17.55

159

Uniform Rate of Progress Glide Path
Mammoth Cave - 20% Most Impaired Data Days

Original

29.83
28.16
25.15
21.81
20.23
18.47
15.13
11.79
9.79

Haziness Index (Deciviews)

Year

— Glide Path
— Natural Condition (Most Impaired)
◆ Observation (Most Impaired)
— Model Projection (Most Impaired)
— Rolling Average (Most Impaired)

160

Uniform Rate of Progress Glide Path
Linville Gorge - 20% Most Impaired Data Days

Original

28.05
26.52
23.77
20.71
17.65
15.51
14.59
11.53
9.70

Haziness Index (Deciviews)

Year

Glide Path — Natural Condition (Most Impaired)
Observation (Most Impaired) — Model Projection (Most Impaired)
Rolling Average (Most Impaired)

Uniform Rate of Progress Glide Path
Shining Rock - 20% Most Impaired Data Days

**Uniform Rate of Progress Glide Path
Swanquarter - 20% Most Impaired Data Days**

Uniform Rate of Progress Glide Path
Cape Romain - 20% Most Impaired Data Days

Original

Legend:
- Glide Path
- Observation (Most Impaired)
- Rolling Average (Most Impaired)
- Natural Condition (Most Impaired)
- Model Projection (Most Impaired)

Data labels: 25.25, 23.96, 21.64, 19.07, 17.31, 16.49, 13.91, 11.34, 9.79

Y-axis: Haziness Index (Deciviews)
X-axis: Year

164

Uniform Rate of Progress Glide Path
Great Smoky Mountains - 20% Most Impaired Data Days

Data labels on chart:
29.16
27.56
24.70
21.51
18.33
16.21
15.14
11.96
10.05

Y-axis: Haziness Index (Deciviews)
X-axis: Year

Legend:
—△— Glide Path
——— Natural Condition (Most Impaired)
◆ Observation (Most Impaired)
—△— Model Projection (Most Impaired)
——— Rolling Average (Most Impaired)

165

Uniform Rate of Progress Glide Path
James River Face - 20% Most Impaired Data Days

**Uniform Rate of Progress Glide Path
Shenandoah - 20% Most Impaired Data Days**

Original

Haziness Index (Deciviews) — Year

28.32
26.76
23.94
20.80
17.67
15.91
14.53
11.40
9.52

Glide Path — Natural Condition (Most Impaired)
Observation (Most Impaired) — Model Projection (Most Impaired)
Rolling Average (Most Impaired)

167

Uniform Rate of Progress Glide Path
Dolly Sods - 20% Most Impaired Data Days

Original

Haziness Index (Deciviews) vs Year

- 28.29
- 26.67
- 23.77
- 20.54
- 17.31
- 16.70
- 14.08
- 10.86
- 8.92

Legend:
- Glide Path
- Natural Condition (Most Impaired)
- Observation (Most Impaired)
- Model Projection (Most Impaired)
- Rolling Average (Most Impaired)

Uniform Rate of Progress Glide Path
Caney Creek - 20% Most Impaired Data Days

Chart showing Haziness Index (Deciviews) versus Year (2000–2064). Glide Path values labeled: 23.99, 22.78, 20.60, 18.18, 19.41, 15.76, 13.34, 10.92, 9.47.

Legend:
- Glide Path
- Natural Condition (Most Impaired)
- Observation (Most Impaired)
- Model Projection (Most Impaired)
- Rolling Average (Most Impaired)

**Uniform Rate of Progress Glide Path
Upper Buffalo - 20% Most Impaired Data Days**

Original

Legend:
- Glide Path
- Observation (Most Impaired)
- Rolling Average (Most Impaired)
- Natural Condition (Most Impaired)
- Model Projection (Most Impaired)

Data labels on chart: 24.25, 23.02, 20.79, 18.32, 18.91, 15.85, 13.38, 10.91, 9.43

Y-axis: Haziness Index (Deciviews)
X-axis: Year

170

Uniform Rate of Progress Glide Path
Hercules - Glade - 20% Most Impaired Data Days

Uniform Rate of Progress Glide Path
Mingo - 20% Most Impaired Data Days

Original

Haziness Index (Deciviews) vs Year

Data labels: 26.26, 24.85, 22.30, 19.47, 20.43, 16.64, 13.81, 10.98, 9.28

Legend:
- Glide Path
- Natural Condition (Most Impaired)
- Observation (Most Impaired)
- Model Projection (Most Impaired)
- Rolling Average (Most Impaired)

172

Uniform Rate of Progress Glide Path
Brigantine - 20% Most Impaired Data Days

173

Sipsey Wilderness Area (AL)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	337.7	3.31%	1.61%	2.22%	0.57%	0.04%	0.05%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	690.9	0.38%	2.75%	1.99%	0.01%	0.09%	0.13%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	398.4	5.72%	4.09%	1.99%	0.31%	0.23%	0.31%
IN	18051-7363111	Gibson	448.7	2.85%	2.12%	1.65%	0.27%	0.19%	0.18%
IN	18125-7362411	INDIANAPOLIS POWER & LIGHT PETERSBURG	464.4	1.72%	2.19%	1.57%	0.23%	0.23%	0.16%
TN	47161-4979311	TVA CUMBERLAND FOSSIL PLANT	228.9	3.18%	1.07%	1.48%	0.48%	0.12%	0.17%
MO	29143-5363811	NEW MADRID POWER PLANT-MARSTON	314.5	3.48%	1.46%	1.34%	0.26%	0.06%	0.07%
KY	21183-5561611	Big Rivers Electric Corp - Wilson Station	345.5	1.99%	0.93%	1.29%	0.07%	0.04%	0.05%
		Facilities That Dropped Off After REVISION							
IL	17127-7808911	Joppa Steam	346.5	1.94%	1.51%	0.82%	0.25%	0.03%	0.02%
IN	18173-8183111	ALCOA WARRICK POWER PLT AGC DIV OF AL	396.3	0.91%	1.02%	0.41%	0.62%	0.52%	0.19%

Chassahowitzka Wilderness Area (FL)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
FL	12017-640611	DUKE ENERGY FLORIDA, INC. (DEF)	27.4	63.62%	9.55%	6.24%	1.95%	0.40%	0.23%
GA	13015-2813011	Ga Power Company - Plant Bowen	637.2	0.03%	1.72%	2.28%	0.00%	0.02%	0.03%
FL	12057-538611	TAMPA ELECTRIC COMPANY (TEC)	106.8	4.73%	0.96%	1.28%	0.24%	0.05%	0.07%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	1,098.0	0.03%	0.76%	1.01%	0.00%	0.04%	0.05%
AL	01109-985711	Sanders Lead Co	471.2	0.15%	0.76%	1.00%	0.00%	0.01%	0.01%
		Facilities That Dropped Off After REVISION							
AR	05063-1083411	ENTERGY ARKANSAS INC-INDEPENDENCE PLANT	1,133.4	0.05%	1.47%	0.83%	0.00%	0.09%	0.04%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	1,099.6	0.03%	1.13%	0.53%	0.00%	0.04%	0.06%
AL	01053-7440211	Escambia Operating Company LLC	530.7	0.21%	1.57%	0.41%	0.00%	0.01%	0.01%

Everglades NP (FL)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
FL	12057-538611	TAMPA ELECTRIC COMPANY (TEC)	316.6	3.02%	2.56%	3.30%	0.08%	0.00%	0.00%
FL	12105-919811	MOSAIC FERTILIZER, LLC	304.7	2.21%	2.09%	2.62%	0.01%	0.00%	0.00%
FL	12105-717711	MOSAIC FERTILIZER LLC	303.3	2.26%	3.55%	2.60%	0.02%	0.00%	0.00%
FL	12086-899911	TARMAC AMERICA LLC	61.7	0.16%	0.17%	0.23%	2.02%	0.76%	2.63%

St Marks Wilderness Area (FL)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
GA	13015-2813011	Ga Power Company - Plant Bowen	452.9	0.38%	3.59%	4.89%	0.01%	0.03%	0.03%
FL	12005-535411	ROCKTENN CP LLC	140.8	8.54%	3.38%	4.60%	0.24%	0.09%	0.13%
AL	01109-985711	Sanders Lead Co	255.9	3.06%	0.82%	1.12%	0.00%	0.00%	0.00%
		Facilities That Dropped Off After REVISION							
AL	01097-1056111	Ala Power - Barry	383.1	1.67%	1.43%	0.97%	0.03%	0.02%	0.03%
AL	01053-7440211	Escambia Operating Company LLC	325.6	5.95%	3.53%	0.96%	0.01%	0.00%	0.00%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	908.4	0.33%	1.67%	0.80%	0.00%	0.01%	0.01%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	1,251.0	0.29%	1.29%	0.65%	0.01%	0.00%	0.00%
AL	01053-985111	Escambia Operating Company LLC	315.0	0.00%	1.68%	0.02%	0.00%	0.00%	0.00%

Cohutta Wilderness Area (GA)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	512.0	1.71%	3.41%	2.44%	0.02%	0.05%	0.07%
GA	13015-2813011	Ga Power Company - Plant Bowen	78.0	19.58%	1.56%	2.13%	1.15%	0.03%	0.04%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	457.2	2.18%	1.05%	1.44%	0.07%	0.01%	0.02%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	410.1	4.68%	2.84%	1.37%	0.13%	0.03%	0.04%
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	454.6	1.05%	2.06%	1.31%	0.06%	0.03%	0.04%
TN	47163-3982311	EASTMAN CHEMICAL COMPANY	269.8	0.99%	0.92%	1.25%	0.09%	0.07%	0.09%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	801.1	0.14%	2.06%	1.04%	0.00%	0.01%	0.01%
IN	18051-7363111	Gibson	487.1	2.31%	1.35%	1.03%	0.10%	0.02%	0.02%
		Facilities That Dropped Off After REVISION							
IN	18125-7362411	INDIANAPOLIS POWER & LIGHT PETERSBURG	477.0	2.18%	1.19%	0.84%	0.16%	0.03%	0.02%
TN	47145-4979111	TVA KINGSTON FOSSIL PLANT	124.0	2.17%	1.10%	0.34%	0.13%	0.06%	0.02%

Okefenokee Wilderness Area (GA)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
FL	12047-769711	WHITE SPRINGS AGRICULTURAL CHEMICALS,INC	71.5	14.63%	4.32%	2.77%	0.03%	0.01%	0.01%
GA	13015-2813011	Ga Power Company - Plant Bowen	458.1	1.02%	1.74%	2.30%	0.05%	0.04%	0.05%
FL	12123-752411	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	153.5	2.18%	1.64%	2.16%	0.14%	0.11%	0.14%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	909.1	0.46%	2.19%	1.51%	0.01%	0.01%	0.01%
FL	12089-753711	ROCK TENN CP, LLC	64.8	12.82%	1.00%	1.31%	0.88%	0.11%	0.15%
SC	45015-4120411	SANTEE COOPER CROSS GENERATING STATION	348.1	0.85%	0.89%	1.18%	0.05%	0.03%	0.04%
GA	13051-3679811	International Paper - Savannah	178.9	2.81%	0.79%	1.04%	0.08%	0.05%	0.06%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	939.4	0.23%	0.78%	1.03%	0.00%	0.03%	0.04%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	1,129.0	0.46%	2.09%	1.02%	0.01%	0.01%	0.01%
Facilities That Dropped Off After REVISION									
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	921.9	0.09%	1.34%	0.83%	0.00%	0.01%	0.01%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	915.7	0.55%	1.40%	0.65%	0.01%	0.02%	0.03%

Wolf Island Wilderness (GA)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
FL	12089-753711	ROCK TENN CP, LLC	74.9	8.56%	1.79%	2.35%	0.39%	0.11%	0.14%
GA	13015-2813011	Ga Power Company - Plant Bowen	458.1	1.08%	1.78%	2.33%	0.03%	0.04%	0.05%
GA	13127-3721011	Brunswick Cellulose Inc	27.9	8.84%	1.34%	1.76%	2.94%	0.10%	0.13%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	845.3	1.71%	2.51%	1.73%	0.02%	0.02%	0.02%
GA	13051-3679811	International Paper - Savannah	85.9	7.53%	1.18%	1.54%	0.24%	0.07%	0.09%
SC	45015-4120411	SANTEE COOPER CROSS GENERATING STATION	251.0	1.59%	0.99%	1.30%	0.09%	0.06%	0.08%
FL	12031-640211	JEA	105.1	4.43%	0.96%	1.29%	0.09%	0.03%	0.06%
SC	45015-4834911	ALUMAX OF SOUTH CAROLINA	223.0	1.84%	0.95%	1.25%	0.00%	0.01%	0.01%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	1,048.6	0.84%	2.37%	1.15%	0.01%	0.01%	0.01%
Facilities That Dropped Off After REVISION									
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	876.1	0.07%	1.25%	0.76%	0.00%	0.02%	0.02%
FL	12047-769711	WHITE SPRINGS AGRICULTURAL CHEMICALS,INC	173.6	1.97%	1.05%	0.67%	0.01%	0.01%	0.01%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	899.0	0.37%	1.38%	0.64%	0.00%	0.02%	0.03%

Mammoth Cave NP (KY)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	118.0	16.88%	3.57%	1.68%	2.60%	0.26%	0.33%
IN	18051-7363111	Gibson	198.2	5.21%	2.16%	1.63%	1.20%	0.35%	0.33%
KY	21183-5561611	Big Rivers Electric Corp - Wilson Station	89.9	6.72%	1.07%	1.43%	0.37%	0.06%	0.08%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	233.6	1.60%	0.86%	1.15%	0.15%	0.14%	0.19%
MO	29143-5363811	NEW MADRID POWER PLANT-MARSTON	312.7	0.66%	1.29%	1.14%	0.04%	0.07%	0.09%
IN	18125-7362411	INDIANAPOLIS POWER & LIGHT PETERSBURG	182.9	3.09%	1.50%	1.04%	0.96%	0.40%	0.27%
Facilities That Dropped Off After REVISION									
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	256.1	1.21%	1.43%	0.89%	0.14%	0.11%	0.12%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	406.5	1.45%	1.15%	0.81%	0.04%	0.02%	0.02%
AR	05063-1083411	ENTERGY ARKANSAS INC-INDEPENDENCE PLANT	498.6	0.30%	1.15%	0.65%	0.04%	0.05%	0.02%
IN	18173-8183111	ALCOA WARRICK POWER PLT AGC DIV OF AL	136.1	2.00%	1.03%	0.40%	1.74%	0.82%	0.30%
IN	18129-8166111	Sigeco AB Brown South Indiana Gas & Ele	162.9	2.73%	1.16%	0.00%	0.27%	0.06%	0.00%

Linville Gorge Wilderness Area (NC)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
TN	47163-3982311	EASTMAN CHEMICAL COMPANY	81.9	19.21%	2.87%	4.05%	0.68%	0.07%	0.10%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	329.2	5.90%	4.67%	3.46%	0.04%	0.01%	0.02%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	567.5	0.94%	3.49%	1.82%	0.00%	0.00%	0.00%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	626.3	0.28%	0.95%	1.34%	0.00%	0.01%	0.02%
TN	47161-4979311	TVA CUMBERLAND FOSSIL PLANT	516.6	0.11%	0.85%	1.20%	0.00%	0.01%	0.01%
GA	13015-2813011	Ga Power Company - Plant Bowen	340.9	0.53%	0.80%	1.13%	0.02%	0.00%	0.00%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	503.5	1.18%	2.22%	1.10%	0.01%	0.07%	0.09%
IN	18051-7363111	Gibson	582.3	0.67%	1.35%	1.07%	0.01%	0.07%	0.07%
MO	29143-5363811	NEW MADRID POWER PLANT-MARSTON	688.6	0.03%	1.11%	1.04%	0.00%	0.00%	0.00%
VA	51027-4034811	Jewell Coke Company LLP	140.4	5.34%	0.73%	1.02%	0.01%	0.00%	0.00%
		Facilities That Dropped Off After REVISION							
AR	05063-1083411	ENTERGY ARKANSAS INC-INDEPENDENCE PLANT	856.4	0.29%	1.43%	0.86%	0.00%	0.01%	0.00%
MD	24001-7763811	Luke Paper Company	463.8	0.23%	1.37%	0.84%	0.00%	0.00%	0.00%
IN	18125-7362411	INDIANAPOLIS POWER & LIGHT PETERSBURG	550.5	0.36%	1.12%	0.82%	0.01%	0.07%	0.05%
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	380.3	2.82%	1.00%	0.66%	0.03%	0.02%	0.03%

Shining Rock Wilderness Area (NC)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	397.3	1.39%	3.26%	2.41%	0.01%	0.01%	0.01%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	573.4	0.47%	1.16%	1.63%	0.01%	0.02%	0.02%
TN	47161-4979311	TVA CUMBERLAND FOSSIL PLANT	454.1	0.54%	0.93%	1.32%	0.02%	0.01%	0.02%
GA	13015-2813011	Ga Power Company - Plant Bowen	241.6	1.70%	0.92%	1.29%	0.07%	0.01%	0.01%
MO	29143-5363811	NEW MADRID POWER PLANT-MARSTON	625.2	0.36%	1.37%	1.28%	0.00%	0.01%	0.01%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	473.3	0.70%	2.55%	1.27%	0.01%	0.07%	0.09%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	657.6	0.49%	2.36%	1.23%	0.00%	0.00%	0.00%
IN	18051-7363111	Gibson	554.2	0.29%	1.55%	1.23%	0.01%	0.07%	0.07%
NC	37087-7920511	Blue Ridge Paper Products - Canton Mill	16.9	41.29%	2.14%	1.08%	6.65%	0.07%	0.10%
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	406.7	1.37%	1.59%	1.05%	0.03%	0.01%	0.01%
AR	05063-1083411	ENTERGY ARKANSAS INC-INDEPENDENCE PLANT	783.3	0.13%	1.74%	1.04%	0.00%	0.01%	0.01%
TN	47163-3982311	EASTMAN CHEMICAL COMPANY	126.9	4.43%	0.74%	1.04%	0.40%	0.02%	0.02%
		Facilities That Dropped Off After REVISION							
IN	18125-7362411	INDIANAPOLIS POWER & LIGHT PETERSBURG	529.0	0.18%	1.12%	0.82%	0.01%	0.11%	0.08%
IL	17127-7808911	Joppa Steam	582.4	0.23%	1.07%	0.59%	0.00%	0.01%	0.00%

Swanquarter Wilderness Area (NC)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	640.2	3.00%	6.66%	3.44%	0.08%	0.08%	0.09%
NC	37013-8479311	PCS Phosphate Company, Inc. - Aurora	52.5	37.89%	2.16%	3.02%	0.57%	0.05%	0.06%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	651.5	1.77%	2.74%	2.01%	0.06%	0.03%	0.05%
OH	39081-8115711	Cardinal Power Plant (Cardinal Operating Company) (0641050002)	659.6	0.35%	1.00%	1.86%	0.02%	0.03%	0.06%
MD	24001-7763811	Luke Paper Company	512.5	0.43%	2.88%	1.75%	0.02%	0.05%	0.07%
WV	54033-6271711	ALLEGHENY ENERGY SUPPLY CO, LLC-HARRISON	568.6	0.67%	1.19%	1.71%	0.08%	0.10%	0.12%
PA	42063-3005211	HOMER CITY GEN LP/ CENTER TWP	620.1	0.55%	1.27%	1.38%	0.05%	0.05%	0.07%
WV	54073-4782811	MONONGAHELA POWER CO-PLEASANTS POWER STA	625.7	0.84%	1.22%	1.17%	0.07%	0.03%	0.05%
GA	13015-2813011	Ga Power Company - Plant Bowen	810.6	0.15%	0.74%	1.03%	0.00%	0.02%	0.03%
NC	37117-8049311	Domtar Paper Company, LLC	69.0	2.27%	0.72%	1.00%	1.02%	0.14%	0.20%
Facilities That Dropped Off After REVISION									
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	1,005.3	0.34%	1.69%	0.83%	0.02%	0.03%	0.04%

Cape Romain Wilderness Area (SC)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
SC	45019-4973611	KAPSTONE CHARLESTON KRAFT LLC	29.3	30.18%	2.86%	3.73%	2.74%	0.25%	0.33%
GA	13015-2813011	Ga Power Company - Plant Bowen	506.2	0.36%	2.71%	3.53%	0.01%	0.10%	0.14%
SC	45015-4834911	ALUMAX OF SOUTH CAROLINA	39.1	17.07%	1.79%	2.33%	0.03%	0.02%	0.02%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	857.1	0.30%	4.74%	2.28%	0.00%	0.01%	0.01%
SC	45015-4120411	SANTEE COOPER CROSS GENERATING STATION	63.8	6.57%	1.73%	2.25%	0.45%	0.21%	0.27%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	701.0	0.84%	3.18%	2.17%	0.00%	0.03%	0.04%
SC	45043-5698611	INTERNATIONAL PAPER GEORGETOWN MILL	57.4	4.31%	1.26%	1.64%	0.35%	0.11%	0.15%
SC	45043-6652811	SANTEE COOPER WINYAH GENERATING STATION	51.4	4.60%	1.02%	1.33%	0.38%	0.13%	0.17%
GA	13051-3679811	International Paper - Savannah	166.1	1.76%	0.99%	1.28%	0.04%	0.05%	0.06%
Facilities That Dropped Off After REVISION									
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	776.2	0.11%	1.14%	0.69%	0.00%	0.04%	0.04%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	868.3	0.06%	1.18%	0.54%	0.00%	0.07%	0.08%

Great Smoky Mountains National Park (TN/NC)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	400.5	2.25%	5.10%	3.73%	0.04%	0.02%	0.02%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	465.3	1.34%	0.94%	1.32%	0.02%	0.06%	0.08%
TN	47163-3982311	EASTMAN CHEMICAL COMPANY	160.1	6.01%	0.88%	1.22%	0.19%	0.04%	0.05%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	688.2	0.11%	2.31%	1.19%	0.00%	0.01%	0.01%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	375.5	4.66%	2.42%	1.19%	0.21%	0.19%	0.25%
IN	18051-7363111	Gibson	456.3	1.25%	1.34%	1.05%	0.07%	0.27%	0.27%
Facilities That Dropped Off After REVISION									
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	360.0	1.84%	1.50%	0.98%	0.09%	0.02%	0.02%
IN	18125-7362411	INDIANAPOLIS POWER & LIGHT PETERSBURG	435.6	1.48%	1.08%	0.78%	0.12%	0.29%	0.20%
AR	05063-1083411	ENTERGY ARKANSAS INC-INDEPENDENCE PLANT	675.9	0.19%	1.22%	0.72%	0.02%	0.01%	0.00%
TN	47145-4979111	TVA KINGSTON FOSSIL PLANT	60.0	7.38%	1.23%	0.38%	0.71%	0.08%	0.03%

Joyce Kilmer-Slickrock Wilderness Area (TN/NC)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	425.1	4.73%	4.69%	3.45%	0.05%	0.01%	0.01%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	472.8	0.84%	0.99%	1.38%	0.05%	0.07%	0.10%
TN	47163-3982311	EASTMAN CHEMICAL COMPANY	179.2	5.88%	0.93%	1.30%	0.16%	0.02%	0.02%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	711.0	0.27%	2.17%	1.12%	0.00%	0.00%	0.00%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	391.2	4.33%	2.27%	1.12%	0.14%	0.16%	0.22%
GA	13015-2813011	Ga Power Company - Plant Bowen	166.2	3.61%	0.79%	1.11%	0.10%	0.01%	0.01%
IN	18051-7363111	Gibson	471.7	2.00%	1.29%	1.02%	0.11%	0.21%	0.21%
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	385.1	3.63%	1.53%	1.00%	0.06%	0.01%	0.01%
		Facilities That Dropped Off After REVISION							
AR	05063-1083411	ENTERGY ARKANSAS INC-INDEPENDENCE PLANT	674.4	1.58%	1.36%	0.81%	0.05%	0.02%	0.01%
IN	18125-7362411	INDIANAPOLIS POWER & LIGHT PETERSBURG	453.0	2.16%	1.00%	0.72%	0.14%	0.23%	0.16%
TN	47145-4979111	TVA KINGSTON FOSSIL PLANT	73.7	7.86%	1.24%	0.39%	0.57%	0.10%	0.03%

James River Face Wilderness Area (VA)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	270.2	7.66%	5.44%	4.04%	0.14%	0.08%	0.11%
WV	**54033-6271711**	**ALLEGHENY ENERGY SUPPLY CO, LLC-HARRISON**	**207.6**	**2.76%**	**2.51%**	**3.65%**	**0.36%**	**0.12%**	**0.14%**
OH	39081-8115711	Cardinal Power Plant (Cardinal Operating Company) (0641050002)	306.4	1.35%	1.92%	3.61%	0.04%	0.02%	0.06%
WV	**54073-4782811**	**MONONGAHELA POWER CO-PLEASANTS POWER STA**	**248.0**	**3.87%**	**2.33%**	**2.26%**	**0.15%**	**0.03%**	**0.05%**
WV	**54079-6789111**	**APPALACHIAN POWER COMPANY - JOHN E AMOS PLANT**	**223.5**	**3.50%**	**2.46%**	**1.93%**	**0.13%**	**0.05%**	**0.11%**
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	337.1	2.98%	2.88%	1.51%	0.06%	0.03%	0.04%
VA	**51580-5798711**	**Meadwestvaco Packaging Resource Group**	**46.5**	**12.64%**	**1.02%**	**1.45%**	**1.14%**	**0.15%**	**0.22%**
OH	39053-7983011	Ohio Valley Electric Corp., Kyger Creek Station (0627000003)	270.0	0.63%	0.66%	1.18%	0.16%	0.04%	0.04%
WV	**54051-6902311**	**MITCHELL PLANT**	**269.6**	**0.68%**	**0.97%**	**1.08%**	**0.03%**	**0.02%**	**0.04%**
Facilities That Dropped Off After REVISION									
OH	*39025-8294311*	*Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)*	*435.2*	*1.89%*	*1.39%*	*0.92%*	*0.05%*	*0.05%*	*0.06%*
IN	*18051-7363111*	*Gibson*	*729.4*	*0.59%*	*1.02%*	*0.82%*	*0.02%*	*0.01%*	*0.01%*
IN	*18147-8017211*	*INDIANA MICHIGAN POWER DBA AEP ROCKPORT*	*663.5*	*0.56%*	*1.33%*	*0.66%*	*0.03%*	*0.01%*	*0.02%*

Shenandoah National Park (VA)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	249.8	11.83%	8.89%	4.81%	0.10%	0.05%	0.06%
OH	39081-8115711	Cardinal Power Plant (Cardinal Operating Company) (0641050002)	269.6	1.53%	2.32%	4.50%	0.06%	0.05%	0.12%
WV	**54033-6271711**	**ALLEGHENY ENERGY SUPPLY CO, LLC-HARRISON**	**189.7**	**4.60%**	**2.75%**	**4.14%**	**0.99%**	**0.37%**	**0.46%**
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	323.4	5.25%	4.88%	3.75%	0.14%	0.10%	0.14%
WV	**54073-4782811**	**MONONGAHELA POWER CO-PLEASANTS POWER STA**	**265.0**	**4.97%**	**2.20%**	**2.20%**	**0.24%**	**0.18%**	**0.28%**
PA	42063-3005211	HOMER CITY GEN LP/ CENTER TWP	230.4	2.60%	1.56%	1.78%	0.13%	0.04%	0.06%
MD	24001-7763811	Luke Paper Company	118.4	6.90%	2.20%	1.41%	0.23%	0.09%	0.14%
PA	42063-3005111	NRG WHOLESALE GEN/SEWARD GEN STA	215.5	1.80%	1.00%	1.12%	0.04%	0.02%	0.02%
WV	**54051-6902311**	**MITCHELL PLANT**	**251.8**	**1.46%**	**0.88%**	**1.01%**	**0.11%**	**0.08%**	**0.16%**
OH	39053-7983011	Ohio Valley Electric Corp., Kyger Creek Station (0627000003)	324.1	0.43%	0.55%	1.01%	0.16%	0.06%	0.06%
Facilities That Dropped Off After REVISION									
WV	*54061-6773611*	*MONONGAHELA POWER CO.- FORT MARTIN POWER*	*184.4*	*2.41%*	*1.06%*	*0.97%*	*1.27%*	*0.47%*	*0.60%*
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	505.4	1.31%	1.28%	0.87%	0.11%	0.05%	0.06%
WV	*54079-6789111*	*APPALACHIAN POWER COMPANY - JOHN E AMOS PLANT*	*295.6*	*2.09%*	*1.04%*	*0.84%*	*0.09%*	*0.09%*	*0.19%*
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	755.8	0.71%	1.46%	0.76%	0.03%	0.02%	0.03%

Dolly Sods Wilderness Area (WV)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
WV	54033-6271711	ALLEGHENY ENERGY SUPPLY CO, LLC-HARRISON	83.6	13.58%	4.94%	7.18%	1.36%	0.26%	0.31%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	233.8	7.62%	6.56%	4.88%	0.10%	0.03%	0.05%
WV	54073-4782811	MONONGAHELA POWER CO-PLEASANTS POWER STA	163.9	4.64%	4.32%	4.19%	0.16%	0.07%	0.10%
OH	39081-8115711	Cardinal Power Plant (Cardinal Operating Company) (0641050002)	163.9	1.36%	2.14%	4.02%	0.03%	0.01%	0.03%
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	416.9	1.40%	2.25%	1.49%	0.02%	0.04%	0.05%
WV	54051-6902311	MITCHELL PLANT	144.2	1.45%	1.28%	1.42%	0.07%	0.02%	0.05%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	172.8	4.12%	2.43%	1.27%	0.01%	0.00%	0.00%
OH	39053-7983011	Ohio Valley Electric Corp., Kyger Creek Station (0627000003)	234.9	0.62%	0.66%	1.18%	0.11%	0.02%	0.02%
WV	54079-6789111	APPALACHIAN POWER COMPANY - JOHN E AMOS PLANT	219.8	3.56%	1.45%	1.14%	0.11%	0.01%	0.03%
WV	54061-6773611	MONONGAHELA POWER CO.- FORT MARTIN POWER	79.8	6.53%	1.27%	1.13%	1.07%	0.18%	0.23%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	847.6	0.12%	0.74%	1.05%	0.00%	0.01%	0.02%
		Facilities That Dropped Off After REVISION							
IN	18051-7363111	Gibson	729.5	0.04%	1.24%	0.99%	0.02%	0.04%	0.04%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	676.3	0.44%	1.93%	0.97%	0.01%	0.02%	0.03%
IN	18125-7362411	INDIANAPOLIS POWER & LIGHT PETERSBURG	682.6	0.18%	1.05%	0.77%	0.02%	0.04%	0.03%
OH	39031-8010811	Conesville Power Plant (0616000000)	242.3	0.71%	1.09%	0.00%	0.12%	0.08%	0.00%

Otter Creek Wilderness Area (WV)

State	Facility ID	Facility Name	DISTANCE_km	Sulfate AOI %	Original Sulfate PSAT %	FINAL Revised Sulfate PSAT %	Nitrate AOI %	Original Nitrate PSAT %	FINAL Revised Nitrate PSAT %
WV	54033-6271711	ALLEGHENY ENERGY SUPPLY CO, LLC-HARRISON	72.8	17.37%	4.49%	6.51%	1.81%	0.26%	0.31%
OH	39053-8148511	General James M. Gavin Power Plant (0627010056)	214.2	10.46%	7.08%	5.25%	0.18%	0.04%	0.06%
WV	54073-4782811	MONONGAHELA POWER CO-PLEASANTS POWER STA	148.3	8.19%	4.39%	4.24%	0.30%	0.08%	0.12%
OH	39081-8115711	Cardinal Power Plant (Cardinal Operating Company) (0641050002)	162.7	1.94%	2.03%	3.81%	0.05%	0.02%	0.04%
OH	39025-8294311	Duke Energy Ohio, Wm. H. Zimmer Station (1413090154)	397.5	1.12%	2.40%	1.58%	0.02%	0.06%	0.06%
WV	54051-6902311	MITCHELL PLANT	136.8	1.56%	1.40%	1.56%	0.06%	0.03%	0.05%
WV	54079-6789111	APPALACHIAN POWER COMPANY - JOHN E AMOS PLANT	198.0	4.36%	1.67%	1.31%	0.12%	0.02%	0.04%
OH	39053-7983011	Ohio Valley Electric Corp., Kyger Creek Station (0627000003)	215.3	0.85%	0.71%	1.27%	0.20%	0.02%	0.02%
KY	21145-6037011	Tennessee Valley Authority (TVA) - Shawnee Fossil Plant	826.5	0.18%	0.77%	1.09%	0.00%	0.01%	0.02%
IN	18051-7363111	Gibson	709.7	0.24%	1.27%	1.01%	0.01%	0.05%	0.05%
WV	54061-6773611	MONONGAHELA POWER CO.- FORT MARTIN POWER	82.7	4.98%	1.14%	1.00%	0.92%	0.20%	0.24%
IN	18147-8017211	INDIANA MICHIGAN POWER DBA AEP ROCKPORT	655.7	0.64%	2.01%	1.00%	0.01%	0.03%	0.04%
PA	42005-3866111	GENON NE MGMT CO/KEYSTONE STA	186.5	3.73%	1.91%	1.00%	0.03%	0.00%	0.00%
		Facilities That Dropped Off After REVISION							
IN	18125-7362411	INDIANAPOLIS POWER & LIGHT PETERSBURG	663.0	0.23%	1.07%	0.79%	0.02%	0.04%	0.03%
OH	39031-8010811	Conesville Power Plant (0616000000)	232.8	1.12%	1.07%	0.00%	0.17%	0.08%	0.00%

Appendix G-1e

Lhoist Montevallo Four Factor Analysis Addendum #1 - March 29, 2021

March 29, 2021

Mr. Skyler Sanderson
Environmental Engineering Specialist, Senior
Air Division, Energy Branch
Alabama Department of Environmental Management
1400 Coliseum Boulevard
Montgomery, AL 36110-2400
(334) 270 - 5647
skyler.sanderson@adem.alabama.gov

RE: *Lhoist North America of Alabama, LLC - Montevallo Plant*
Regional Haze Rule – Four-Factor Analysis Additional Information Request

Dear Mr. Sanderson:

Lhoist North America of Alabama, LLC (LNA) owns and operates the Montevallo Plant, comprising of a lime manufacturing facility located in Calera, Shelby County, Alabama operating under Title V Major Source Operating Permit No. 411-0008 issued by the Alabama Department of Environmental Management (ADEM). LNA is submitting this letter in response to the ADEM additional information request letter, dated March 2, 2021, requesting additional information following submittal by LNA of the Four-Factor Analysis for the Montevallo Plant on February 5, 2021.

The key items of concern addressed in this letter are as follows:

- Providing additional alternative fuel scenarios for the four existing rotary lime kilns, including two scenarios requested by ADEM as identified in the March 2nd letter for use of low sulfur coal, as well as additional iterative scenarios for use of low sulfur coal.
- Providing additional alternative fuel scenarios data for the four existing rotary lime kilns, including iterative analyses for usages of additional natural gas beyond the 20% provided in the Four-Factor Analysis submitted on February 5, 2021.

Supporting documentation for this submittal is included in the two attachments to this letter.

- Attachment 1 - Updated detailed economic analysis documentation, including both the previously provided analyses as well as the additional requested analyses as outlined above. This is then effectively an updated version of Appendix A of the Four-Factor Analysis submitted on February 5, 2021.
- Attachment 2 - Documentation from the LNA natural gas provider (Spire), detailing the maximum amount of natural gas that the supplier can physically provide to the facility without natural gas transmission infrastructure projects for the Shelby County area.

The natural gas capacity situation at the facility is a critical and key component to address as part of this submittal to make sure this is fully understood by ADEM. There is currently a physical capacity (interruptible natural gas supply) limitation that LNA is subject to at the facility, as there is a limitation to how much gas that the local natural gas provider can physically supply to the facility. This is not something within the power of LNA to control. Significant work outside of the control of LNA (such as additional pipeline

construction, compression capacity additions, etc.) would be necessary to provide sufficient constant natural gas capacity to run the four existing facility kilns beyond approximately 20% natural gas usage. Therefore, for LNA to use more natural gas than that amount, the local natural gas provider would have to engage in new infrastructure projects outside of the control of LNA.

ADDITIONAL LOW SULFUR COAL ANALYSES

Additional alternative fuel scenarios with use of low sulfur coal were evaluated. A summary of the results of these new analyses is shown below in Table 1, with additional details for those analyses provided in Attachment 1.

Table 1: Additional Low Sulfur Coal Usage Analyses

Scenario	ADEM1	ADEM2	1A	1B	1C	2A	2B	2C	2D	3A	3B	3C	3D	3E
Coal	See Below	See Below	45%	25%	0%	60%	40%	20%	0%	75%	55%	35%	15%	0%
Low S Coal			0%	20%	45%	0%	20%	40%	60%	0%	20%	40%	60%	75%
Coke			46%	46%	46%	31%	31%	31%	31%	16%	16%	16%	16%	16%
Natural Gas			9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%	9%
Kiln 1 Cost Effectivness ($/ton)	$9,123	$47,201	$33,901	$26,479	$20,558	$14,083	$13,384	$12,572	$11,681	$9,667	$9,595	$9,348	$9,136	$8,832
Kiln 2 Cost Effectivness ($/ton)	$8,924	$44,844	$40,324	$29,139	$21,532	$14,123	$13,379	$12,508	$11,553	$9,440	$9,396	$9,153	$8,947	$8,632
Kiln 3 Cost Effectivness ($/ton)	$2,182	$12,079	$6,036	$5,128	$4,293	$3,184	$3,015	$2,847	$2,679	$2,287	$2,240	$2,176	$2,120	$2,063
Kiln 4 Cost Effectivness ($/ton)	$2,079	$11,293	$5,640	$4,811	$4,044	$2,995	$2,845	$2,694	$2,542	$2,162	$2,123	$2,068	$2,019	$1,968
Total Cost Effectivness ($/ton)	$2,871	$15,438	$7,903	$6,730	$5,611	$4,114	$3,929	$3,725	$3,506	$2,965	$2,928	$2,857	$2,795	$2,717

ADEM1 Scenario is the previous Increased Coal Operation analysis with use of low sulfur coal in lieu of current coal. Fuel composition varies per Kiln.
ADEM2 Scenario is consideration of the baseline fuel "current" conditions with use of low sulfur coal in lieu of current coal. Fuel composition varies per Kiln.

As can be seen from the above low sulfur coal analyses, all $/ton cost effectiveness values for the new iterations are approximately $2,000/ton or higher for all of the four facility kilns. Data only begins to show a cost effectiveness of less than $2,000/ton on specific kilns with use of higher percentages of coal (e.g. 75% and greater). At that high of a usage of coal, significant negative influences on facility operations, including significant downtime and costs for dealing with ash ring and plugging build-up within the kilns, would be experienced. Also, use of significantly increased coal quantities at the site, even low sulfur coal, would lead to additional emissions of hazardous air pollutants (HAPs) such as metal HAPs of concern (e.g. mercury), and could also lead to increased emissions of PM_{10} and NOx (other visibility impairing pollutants).

Therefore, LNA does not consider the use of increased amounts of low sulfur coal a viable option for the Facility's kilns.

ADDITIONAL NATURAL GAS ANALYSES

As requested in ADEM's letter dated March 2, 2021, additional economic analyses for increased iterations of natural gas usage beyond the 20% previously evaluated, was conducted for the four facility kilns. Summary results of these new analyses can be seen in Table 2 below, with additional supporting documentation for the analyses in Attachment 1.

Table 2: Additional Natural Gas Usage Analyses

Scenario	NG1	NG2	NG3	NG4
Natural Gas	40%	60%	80%	100%
Coal	25%	20%	10%	0%
Coke	35%	20%	10%	0%
Kiln 1 Cost Effectivness ($/ton)	$4,118	$3,820	$3,761	$3,726
Kiln 2 Cost Effectivness ($/ton)	$4,148	$3,825	$3,764	$3,728
Kiln 3 Cost Effectivness ($/ton)	$842	$790	$779	$773
Kiln 4 Cost Effectivness ($/ton)	$834	$785	$776	$770
Total Cost Effectivness ($/ton)	$1,164	$1,108	$1,099	$1,094

While increased usage of natural gas would seem to be potentially economically viable, as mentioned previously within this letter, the facility simply cannot be physically provided the amount of natural gas needed to run the four existing facility kilns on more than approximately 20% natural gas at this time. As identified in the attached letter from the facility natural gas provider, Spire (Attachment 2 – received via e-mail), the facility can currently be supplied up to 330 MMBtu/hr of interruptible natural gas. Spire could potentially provide more natural gas to the facility in the future following company infrastructure improvements, but the timing of those improvements is unknown and outside of the control of LNA.

With construction of the vertical Kiln 5 soon being completed and designed/permitted to run at 100% load on natural gas, that leaves the remaining natural gas to be distributed amongst the kilns estimated as follows.

[330 MMBtu/hr – 100 MMBtu/hr (Kiln 5 capacity) – 20 MMBtu/hr (Limestone Dryer)] / 4 kilns = 52.5 MMBtu/hr per Kiln

52.5 MMBtu/hr per kiln works out to between approximately 20-25% capacity of the maximum load BTUs necessary to run the kilns at full capacity, depending on the kiln considered (K1/K2 having smaller capacity than K3/K4).

As stated previously, the facility is currently capable of increased usage of natural gas up to 20% on the four existing facility kilns, and LNA considers that the only viable option for the Montevallo Plant at this time for increased natural gas usage, given the limited supply to the facility and the interruptible nature of the gas being provided. The timing for the facility capability to utilize natural gas beyond 20% is outside the control of LNA and up to the natural gas provider Spire.

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If you have any questions or comments about the information presented in this letter, please feel free to contact Michael Will, the Alabama Regional Environmental Manager, at (205) 444-4905 or via email.

Sincerely,

Lhoist North America of Alabama, LLC

Craig Gordinier
Montevallo Plant Manager

Attachments

cc: Mr. Doug Carr (ADEM)
     Ms. Jennifer Youngpeter (ADEM)
     Mr. Chris Scholl (LNA)
     Mr. Michael Will (LNA)

ATTACHMENT 1

Emissions and Costing Calculations - Updated

Table 1. Economic Analysis - Alternative Fuel Scenarios - General Assumptions

Parameters	Value	Unit
Coal Sulfur Content[1]	1.47	%
Coke Sulfur Content[1]	5.25	%
Natural Gas Sulfur Content[2]	2.80E-04	lb S/MMBtu
Coal HHV[1]	26.85	MMBtu/ton
Coke HHV[1]	29.12	MMBtu/ton
Natural Gas HHV[2]	1,020	MMBtu/MMscf
Cost of Coal[3]	3.33	$/MMBtu
Cost of Coke[3]	2.21	$/MMBtu
Cost of Natural Gas[3]	4.16	$/MMBtu
Kilns 1 and 2 Percent of Input Sulfur in LKD/LKS[4]	5.93	%
Kilns 1 and 2 Percent of Input Sulfur in Lime[5]	2.60	%
Kilns 3 and 4 Percent of Input Sulfur in LKD/LKS[4]	13.31	%
Kilns 3 and 4 Percent of Input Sulfur in Lime[5]	7.33	%
SO$_2$ to S Molar Mass Ratio	2	
Low Sulfur Coal Sulfur Content[6]	0.83	%
Low Sulfur Coal HHV[6]	25.89	MMBtu/ton
Cost of Low Sulfur Coal[3]	3.82	$/MMBtu

1. From as received fuel sampling data.
2. Based on AP-42 Section 1.4.
3. Based on quoted fuel costs.
4. Based on Lhoist estimate for the percent of input sulfur that exits in the kiln in lime kiln dust (LKD) or lime kiln suldge (LKS) from 2018 & 2019 data.
5. Based on Lhoist estimate for the percent of input sulfur that exits in the kiln in lime from customer product specifications.
6. From sampling data on Appalachian coal.

Table 2. Economic Analysis - Alternative Fuel Scenarios - Kiln Specific Assumptions[1]

Parameters	Value	Unit
Kiln 1 Fuel Efficiency[1]	10.6	MMBtu/ton production
Kiln 2 Fuel Efficiency[1]	12.0	MMBtu/ton production
Kiln 3 Fuel Efficiency[1]	7.2	MMBtu/ton production
Kiln 4 Fuel Efficiency[1]	7.6	MMBtu/ton production
Input Sulfur Removed by the Kiln 1 Venturi Scrubber[2]	75	%
Input Sulfur Removed by the Kiln 2 Venturi Scrubber[2]	75	%
Heat Input Required for Kiln 1[3]	956,700	MMBtu/yr
Heat Input Required for Kiln 2[3]	910,100	MMBtu/yr
Heat Input Required for Kiln 3[3]	1,440,000	MMBtu/yr
Heat Input Required for Kiln 4[3]	1,518,000	MMBtu/yr

1. Kiln specific parameters and assumptions based on Lhoist estimates for 2018 & 2019
2. Lhoist estimate based on percent of input sulfur removed by the scrubber.
3. Based on review of facility data from 2015-2019

Table 3. Economic Analysis - Alternative Fuel Scenarios - Baseline - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	36.4%	35.6%	38.4%	38.4%
Coke	54.6%	53.4%	57.6%	57.6%
Natural Gas	9.0%	11.0%	4.0%	4.0%

1. Fuel mix based on Lhoist estimates for 2019.

Table 4. Economic Analysis - Alternative Fuel Scenarios - Baseline

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	$ -	$ -	$ -	$ -	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ 1,160,882	$ 1,080,066	$ 1,843,337	$ 1,943,185	$ 6,027,470
Coke	$ 1,153,701	$ 1,073,384	$ 1,831,934	$ 1,931,164	$ 5,990,183
Natural Gas	$ 358,085	$ 416,341	$ 239,546	$ 252,522	$ 1,266,494
Total Annualized Cost[4]	$ 2,672,668	$ 2,569,791	$ 3,914,818	$ 4,126,870	$ 13,284,147

1. Total Capital Investment is equal to the sum of all capital costs.

2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.

3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor

4. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 5. Economic Analysis - Alternative Fuel Scenarios - Baseline - SO_2 Emissions with Add-On Controls

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	62.8	58.4	481	507	1,108
Coke (tpy)[1]	310	288.6	2,373	2,502	5,474
Natural Gas (tpy)[2]	3.97E-03	4.62E-03	1.28E-02	1.35E-02	3.49E-02
Total	373	347	2,854	3,008	6,582

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Table 6. Economic Analysis - Alternative Fuel Scenarios - Max Coal - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	91.0%	91.0%	95.0%	95.0%
Coke	0.0%	0.0%	0.0%	0.0%
Natural Gas	9.0%	9.0%	5.0%	5.0%

1. Fuel mix based on Lhoist estimates for maximum coal usage. Excluding natural gas, this is equivalent to 100% coal.

Table 7. Economic Analysis - Alternative Fuel Scenarios - Max Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	N/A	N/A	N/A	N/A	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ 2,902,206	$ 2,760,842	$ 4,560,340	$ 4,807,358	$ 15,030,746
Coke	$ -	$ -	$ -	$ -	$ -
Natural Gas	$ 358,085	$ 340,643	$ 299,433	$ 315,652	$ 1,313,813
Downtime Revenue Loss[4]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[5]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[6]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[7]	$ 4,321,151	$ 4,031,389	$ 6,998,773	$ 7,212,811	$ 22,564,123

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
5. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
6. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
7. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 8. Economic Analysis - Alternative Fuel Scenarios - Max Coal - SO_2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	157	149	1,189	1,253	2,748
Coke (tpy)[1]	0	0	0	0	0
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	1.60E-02	1.69E-02	4.06E-02
Total	157	149	1,189	1,253	2,749

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Table 9. Economic Analysis - Alternative Fuel Scenarios - Max Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-216	-198	-1,665	-1,755	-3,834
Total Annualized Cost Difference	$ 1,648,483	$ 1,461,598	$ 3,083,955	$ 3,085,940	$ 9,279,976
Cost Effectiveness ($/ton reduced)	$ 7,632	$ 7,393	$ 1,852	$ 1,758	$ 2,421

Table 10. Economic Analysis - Alternative Fuel Scenarios - Increased Coal - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	72.8%	72.8%	76.0%	76.0%
Coke	18.2%	18.2%	19.0%	19.0%
Natural Gas	9.0%	9.0%	5.0%	5.0%

1. Fuel mix based on Lhoist estimates for increased coal usage and reduced coke usage. Excluding natural gas, this is roughly equivalent to 80% coal and 20% coke.

Table 11. Economic Analysis - Alternative Fuel Scenarios - Increased Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	N/A	N/A	N/A	N/A	$ --
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ 2,321,765	$ 2,208,674	$ 3,648,272	$ 3,845,886	$ 12,024,597
Coke	$ 384,567	$ 365,835	$ 604,284	$ 637,016	$ 1,991,702
Natural Gas	$ 358,085	$ 340,643	$ 299,433	$ 315,652	$ 1,313,813
Downtime Revenue Loss[4]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[5]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[6]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[7]	$ 4,125,277	$ 3,845,056	$ 6,690,989	$ 6,888,355	$ 21,549,675

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
5. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
6. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
7. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 12. Economic Analysis - Alternative Fuel Scenarios - Increased Coal - SO_2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	126	120	951	1,003	2,199
Coke (tpy)[1]	103	98.4	783	825	1,810
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	1.60E-02	1.69E-02	4.06E-02
Total	229	218	1,734	1,828	4,009

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Table 13. Economic Analysis - Alternative Fuel Scenarios - Increased Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-144	-129	-1,120	-1,181	-2,574
Total Annualized Cost Difference	$ 1,452,608	$ 1,275,265	$ 2,776,171	$ 2,761,484	$ 8,265,528
Cost Effectiveness ($/ton reduced)	$ 10,087	$ 9,871	$ 2,479	$ 2,339	$ 3,212

Table 14. Economic Analysis - Alternative Fuel Scenarios - Increased Natural Gas - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	28.0%	28.0%	28.0%	28.0%
Coke	52.0%	52.0%	52.0%	52.0%
Natural Gas	20.0%	20.0%	20.0%	20.0%

1. Fuel mix based on Lhoist estimates for increased natural gas usage.

Table 15. Economic Analysis - Alternative Fuel Scenarios - Increased Natural Gas

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	$ -	$ -	$ -	$ -	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ 892,987	$ 849,490	$ 1,344,100	$ 1,416,906	$ 4,503,482
Coke	$ 1,098,763	$ 1,045,243	$ 1,653,829	$ 1,743,412	$ 5,541,247
Natural Gas	$ 795,744	$ 756,984	$ 1,197,732	$ 1,262,610	$ 4,013,069
Total Annualized Cost[4]	$ 2,787,493	$ 2,651,717	$ 4,195,662	$ 4,422,927	$ 14,057,798

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 16. Economic Analysis - Alternative Fuel Scenarios - Increased Natural Gas - SO_2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	48.3	46.0	350	369	814
Coke (tpy)[1]	295	281	2,143	2,259	4,978
Natural Gas (tpy)[2]	8.83E-03	8.40E-03	6.40E-02	6.75E-02	1.49E-01
Total	344	327	2,493	2,628	5,792

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Table 17. Economic Analysis - Alternative Fuel Scenarios - Increased Natural Gas - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-29	-20	-361	-380	-791
Total Annualized Cost Difference	$ 114,825	$ 81,926	$ 280,844	$ 296,056	$ 773,651
Cost Effectiveness ($/ton reduced)	$ 3,924	$ 4,088	$ 778	$ 778	$ 979

Table 18. Economic Analysis - Alternative Fuel Scenarios - Max Low Sulfur Coal - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Low Sulfur Coal	91.0%	91.0%	95.0%	95.0%
Coke	0.0%	0.0%	0.0%	0.0%
Natural Gas	9.0%	9.0%	5.0%	5.0%

1. Fuel mix based on Lhoist estimates for maximum low sulfur coal usage. Excluding natural gas, this is equivalent to 100% low sulfur coal.

Table 19. Economic Analysis - Alternative Fuel Scenarios - Max Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	N/A	N/A	N/A	N/A	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Low Sulfur Coal	$ 3,322,325	$ 3,160,497	$ 5,220,487	$ 5,503,263	$ 17,206,571
Coke	$ -	$ -	$ -	$ -	$ -
Natural Gas	$ 358,085	$ 340,643	$ 299,433	$ 315,652	$ 1,313,813
Downtime Revenue Loss[4]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[5]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[6]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[7]	$ 4,741,269	$ 4,431,044	$ 7,658,920	$ 7,908,715	$ 24,739,948

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
5. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
6. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
7. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 20. Economic Analysis - Alternative Fuel Scenarios - Max Low Sulfur Coal - SO_2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Low Sulfur Coal (tpy)[1]	91.9	87.5	696	734	1,609
Coke (tpy)[1]	0	0.0	0	0	0
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	1.60E-02	1.69E-02	4.06E-02
Total	92.0	87.5	696	734	1,609

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Table 21. Economic Analysis - Alternative Fuel Scenarios - Max Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-281	-260	-2,158	-2,275	-4,973
Total Annualized Cost Difference	$ 2,068,601	$ 1,861,253	$ 3,744,102	$ 3,781,845	$ 11,455,801
Cost Effectiveness ($/ton reduced)	$ 7,359	$ 7,170	$ 1,735	$ 1,663	$ 2,304

Table 22. Economic Analysis - Alternative Control Technologies - Assumptions

Parameters	Value	Unit
Hydrated Lime Cost[1]	150	$/ton
Wet FGD Scrubber Reagent Cost[1]	150	$/ton
Hydrated Lime Injection Control Efficiency (with baghouse)[1]	50	%
Producer Price Index Adjustment[2]	1.078	2019$/2016$
Producer Price Index Adjustment[2]	1.524	2019$/2002$
Producer Price Index Adjustment[2]	1.489	2019$/2001$
Wet FGD Scrubber Control Efficiency[3]	98	%
Kiln 1 Potential Heat Input of Coal and Coke[4]	109	MMBtu/hr
Kiln 2 Potential Heat Input of Coal and Coke[4]	104	MMBtu/hr
Kiln 3 Potential Heat Input of Coal and Coke[4]	164	MMBtu/hr
Kiln 4 Potential Heat Input of Coal and Coke[4]	173	MMBtu/hr
Kiln 1 Exhaust Flow Rate[5]	40,015	dscfm
Kiln 2 Exhaust Flow Rate[5]	37,340	dscfm
Kiln 3 Exhaust Flow Rate[5]	82,529	dscfm
Kiln 4 Exhaust Flow Rate[5]	78,702	dscfm

1. Based on April 2017 Final Report, *Dry Sorbent Injection for SO$_2$/HCl Control Cost Development Methodology*, by Sargent & Lundy, LLC, funded by the U.S. EPA. Control efficiency based on percent of input sulfur removed by the hydrated lime. https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-5_dsi_cost_development_methodology.pdf

The 50% control efficiency estimate from the Sargent & Lundy report is consistent with Lhoist's experience with DSI. Based on DSI testing conducted with Sorbacal® SPS in June 2013 at Lhoist's Nelson, AZ Facility, control efficiency was estimated to be 40%. A vendor previously contacted by Lhoist could only guarantee reduction up to 50%. Based on these factors Lhoist considers the 50% control efficiency used here to be representative of different sorbents such as hydrated lime, Sorbacal®, and trona.

The control efficiency is converted to the effective amount of input sulfur removed based on existing inherent controls to be used in calculations.

2. Based on PPI data from the St. Louis Fed.
https://fred.stlouisfed.org/series/PPIACO#0
3. From the Air Pollution Control Technology Fact Sheet for Flue Gas Desulfurization (2003). Using the highest value in the given range (90% to 98%) for control efficiency. The control efficiency is converted to the effective amount of input sulfur removed based on existing inherent controls to be used in calculations.
4. Based on review of facility data from 2015-2019
5. Based on 2019 & 2018 Annual PM Compliance Stack Testing

Table 23. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Hydrate Injection - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	36.4%	35.6%	38.4%	38.4%
Coke	54.6%	53.4%	57.6%	57.6%
Natural Gas	9.0%	11.0%	4.0%	4.0%

1. Baseline fuel mix.

Table 24. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Hydrate Injection

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
Injection System[1]					
Base Module Cost	$ -	$ -	$ 8,082,524	$ 8,082,524	$ 16,165,049
Other Project Costs	$ -	$ -	$ 1,616,505	$ 1,616,505	$ 3,233,010
Owners Costs	$ -	$ -	$ 80,825	$ 80,825	$ 161,650
Baghouse[2]					
Capital Cost	$ -	$ -	$ 2,012,423	$ 1,919,104	$ 3,931,528
Total Capital Investment[3]	$ -	$ -	$ 11,792,278	$ 11,698,959	$ 23,491,236
Capital Recovery Factor[4]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[5]	$ -	$ -	$ 1,113,108	$ 1,104,299	$ 2,217,407
Annual Costs					
Injection System[1]					
Additional Labor Costs	$ -	$ -	$ 249,600	$ 249,600	$ 499,200
Additional Maintenance Costs	$ -	$ -	$ 80,825	$ 80,825	$ 161,650
Hydrated Lime Costs	$ -	$ -	$ 1,314,000	$ 1,314,000	$ 2,628,000
Waste Disposal Costs	$ -	$ -	$ 1,189,520	$ 1,189,520	$ 2,379,040
Additional Power Costs	$ -	$ -	$ 94,608	$ 94,608	$ 189,216
Baghouse[2]					
O&M Costs	$ -	$ -	$ 628,882	$ 599,720	$ 1,228,602
Indirect Annual Costs[6]					
Overhead	$ -	$ -	$ 1,363,985	$ 1,346,487	$ 2,710,472
Administrative Charges	$ -	$ -	$ 235,846	$ 233,979	$ 469,825
Property Tax	$ -	$ -	$ 117,923	$ 116,990	$ 234,912
Insurance	$ -	$ -	$ 117,923	$ 116,990	$ 234,912
Total Annualized Cost[7]	$ -	$ -	$ 6,506,219	$ 6,447,018	$ 12,953,237

1. Based on April 2017 Final Report, *Dry Sorbent Injection for SO$_2$/HCl Control Cost Development Methodology*, by Sargent & Lundy, LLC, funded by the U.S. EPA. Assumes 1 tph hydrate injection rate and retrofit factor of 1 (per kiln). Cost includes all equipment from unloading to injection, including dehumidification system. Converted from 2016 dollars to 2019 dollars.
https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-5_dsi_cost_development_methodology.pdf

2. Based on the Air Pollution Control Technology Fact Sheet for Pulse-Jet Cleaned Type Fabric Filters (2003). For capital cost, using average costs in terms of $/scfm due to higher temperature tolerance required. For O&M costs, using minimum costs in terms of $/scfm to be conservative. Converted from 2002 dollars to 2019 dollars.
https://nepis.epa.gov/Exe/ZyPDF.cgi/P100RQ6L.PDF?Dockey=P100RQ6L.PDF

3. Total Capital Investment is equal to the sum of all capital costs.

4. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.

5. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor

6. Indirect Annual Costs based on EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.4.

7. Fuel costs are equivalent to baseline fuel costs and are not listed.
Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 25. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Hydrate Injection - SO$_2$ Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	62.8	58.4	240	253	615
Coke (tpy)[1]	310	288.6	1,187	1,251	3,036
Natural Gas (tpy)[2]	3.97E-03	4.62E-03	6.40E-03	6.75E-03	2.17E-02
Total	373	347.1	1,427	1,504	3,651

1. Baseline SO$_2$ Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD (%) - Input Sulfur in Lime (%) - {Input Sulfur Removed by Scrubber (%) OR Input Sulfur Removed by Hydrate Injection (%)}]
2. Baseline SO$_2$ Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton)* Molar Mass Ratio *
[100% - Input Sulfur in LKD (%) - Input Sulfur in Lime (%) - {Input Sulfur Removed by Scrubber (%) OR Input Sulfur Removed by Hydrate Injection (%)}]

Table 26. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Hydrate Injection - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO$_2$ Emissions Difference (tpy)	0	0	-1,427	-1,504	-2,931
Total Annualized Cost Difference	$ -	$ -	$ 6,506,219	$ 6,447,018	$ 12,953,237
Cost Effectiveness ($/ton reduced)	N/A	N/A	$ 4,560	$ 4,286	$ 4,419

Table 27. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Wet FGD Scrubber - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	36.4%	35.6%	38.4%	38.4%
Coke	54.6%	53.4%	57.6%	57.6%
Natural Gas	9.0%	11.0%	4.0%	4.0%

1. Baseline fuel mix.

Table 28. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Wet FGD Scrubber

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
Scrubber Capital Cost[1]	$ --	$ -	$ 6,118,449	$ 6,449,865	$ 12,568,315
Pond Expansion Cost[2]	$ -	$ -	$ 1,000,000	$ 1,000,000	$ 2,000,000
Total Capital Investment[3]	$ -	$ -	$ 7,118,449	$ 7,449,865	$ 14,568,315
Capital Recovery Factor[4]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[5]	$ -	$ -	$ 671,931	$ 703,215	$ 1,375,146
Annual Costs					
Direct Annual Costs					$ --
O&M Costs[1]	$ -	$ -	$ 318,159	$ 335,393	$ 653,552
Reagent Costs[6]	$ -	$ -	$ 1,314,000	$ 1,314,000	$ 2,628,000
Waste Disposal Costs[6]	$ -	$. -	$ 1,189,520	$ 1,189,520	$ 2,379,040
Indirect Annual Costs[7]					
Overhead	$ -	$ -	$ 979,296	$ 989,636	$ 1,968,931
Administrative Charges	$ -	$ -	$ 142,369	$ 148,997	$ 291,366
Property Tax	$ -	$ -	$ 71,184	$ 74,499	$ 145,683
Insurance	$ -	$ -	$ 71,184	$ 74,499	$ 145,683
Downtime Revenue Loss[8]	$ -	$ -	$ 1,537,344	$ 1,502,720	$ 3,040,064
Kiln Startup[9]	$ -	$ -	$ 178,500	$ 140,250	$ 318,750
Total Annualized Cost[10]	$ -	$ -	$ 6,473,488	$ 6,472,728	$ 12,946,216

1. Based on the Air Pollution Control Technology Fact Sheet for Flue Gas Desulfurization (2003). For capital cost, using minimum costs in terms of $/MMBtu/hr for Wet FGD Scrubbers with unit size < 4,000 MMBtu/hr to be conservative. For O&M costs, using average costs in terms of $/MMBtu/hr for Wet FGD Scrubbers with unit size < 4,000 MMBtu/hr to be more representative. Converted from 2001 dollars to 2019 dollars.
https://www.epa.gov/sites/production/files/2020-08/documents/ffdg.pdf
2. Lhoist estimate for expansion of the water pond (required for scrubber water).
3. Total Capital Investment is equal to the sum of all capital costs.
4. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
5. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor

6. Reagent and waste disposal costs assumed to be similar to hydrated lime based on April 2017 Final Report, Dry Sorbent Injection for SO2/HCl Control Cost Development Methodology, by Sargent & Lundy, LLC, funded by the U.S. EPA. Assumes 1 tph reagent usage rate.

7. Indirect Annual Costs based on EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.4.
8. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
9. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
10. Fuel costs are equivalent to baseline fuel costs and are not listed.
Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 29. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Wet FGD Scrubber - SO$_2$ Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	62.8	58.4	10	10	141
Coke (tpy)[1]	310	288.6	47	50	696
Natural Gas (tpy)[2]	3.97E-03	4.62E-03	2.56E-04	2.70E-04	9.12E-03
Total	373	347.1	57	60	837

1. Baseline SO2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber (%)]

2. Baseline SO2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton)* Molar Mass Ratio *
[100% - Input Sulfur in LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber (%)]

Table 30. Economic Analysis - Alternative Control Technologies - Kiln 3 & 4 Wet FGD Scrubber - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO$_2$ Emissions Difference (tpy)	0	0	-2,797	-2,948	-5,745
Total Annualized Cost Difference	$ -	$ -	$ 6,473,488	$ 6,472,728	$ 12,946,216
Cost Effectiveness ($/ton reduced)	N/A	N/A	$ 2,315	$ 2,195	$ 2,253

Table 31. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Hydrate Injection - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	36.4%	35.6%	38.4%	38.4%
Coke	54.6%	53.4%	57.6%	57.6%
Natural Gas	9.0%	11.0%	4.0%	4.0%

1. Baseline fuel mix.

Table 32. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Hydrate Injection

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
Injection System[1]					
Base Module Cost	$ 8,082,524	$ 8,082,524	$ -	$ -	$ 16,165,049
Other Project Costs	$ 1,616,505	$ 1,616,505	$ -	$ -	$ 3,233,010
Owners Costs	$ 80,825	$ 80,825	$ -	$ -	$ 161,650
Baghouse[2]					
Capital Cost	$ 975,731	$ 910,503	$ -	$ -	$ 1,886,234
Total Capital Investment[3]	$ 10,755,586	$ 10,690,357	$ -	$ -	$ 21,445,943
Capital Recovery Factor[4]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[5]	$ 1,015,251	$ 1,009,094	$ -	$ -	$ 2,024,345
Annual Costs					
Injection System[1]					
Additional Labor Costs	$ 249,600	$ 249,600	$ -	$ -	$ 499,200
Additional Maintenance Costs	$ 80,825	$ 80,825	$ -	$ -	$ 161,650
Hydrated Lime Costs	$ 1,314,000	$ 1,314,000	$ -	$ -	$ 2,628,000
Waste Disposal Costs	$ 1,189,520	$ 1,189,520	$ -	$ -	$ 2,379,040
Additional Power Costs	$ 94,608	$ 94,608	$ -	$ -	$ 189,216
Baghouse[2]					
O&M Costs	$ 304,916	$ 284,532	$ -	$ -	$ 589,448
Indirect Annual Costs[6]					
Overhead	$ 1,169,605	$ 1,157,374	$ -	$ -	$ 2,326,979
Administrative Charges	$ 215,112	$ 213,807	$ -	$ -	$ 428,919
Property Tax	$ 107,556	$ 106,904	$ -	$ -	$ 214,459
Insurance	$ 107,556	$ 106,904	$ -	$ -	$ 214,459
Total Annualized Cost[7]	$ 5,848,549	$ 5,807,168	$ -	$ -	$ 11,655,717

1. Based on April 2017 Final Report, *Dry Sorbent Injection for SO₂/HCl Control Cost Development Methodology*, by Sargent & Lundy, LLC, funded by the U.S. EPA. Assumes 1 tph hydrate injection rate and retrofit factor of 1 (per kiln). Cost includes all equipment from unloading to injection, including dehumidification system. Converted from 2016 dollars to 2019 dollars.
https://www.epa.gov/sites/production/files/2018-05/documents/attachment_5-5_dsi_cost_development_methodology.pdf

2. Based on the Air Pollution Control Technology Fact Sheet for Pulse-Jet Cleaned Type Fabric Filters (2003). For capital cost, using average costs in terms of $/scfm due to higher temperature tolerance required. For O&M costs, using minimum costs in terms of $/scfm to be conservative. Converted from 2002 dollars to 2019 dollars.
https://nepis.epa.gov/Exe/ZyPDF.cgi/P100RQ6L.PDF?Dockey=P100RQ6L.PDF

3. Total Capital Investment is equal to the sum of all capital costs.

4. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.

5. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor

6. Indirect Annual Costs based on EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.4.

7. Fuel costs are equivalent to baseline fuel costs and are not listed.
Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 33. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Hydrate Injection - SO$_2$ Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	174.4	162.3	481	507	1,324
Coke (tpy)[1]	861	801.4	2,373	2,502	6,538
Natural Gas (tpy)[2]	1.10E-02	1.28E-02	1.28E-02	1.35E-02	5.02E-02
Total	1036	963.7	2,854	3,008	7,862

1. Baseline SO2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Hydrate Injection (%) {Kilns 1 & 2 only}]
2. Baseline SO2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton)* Molar Mass Ratio *
[100% - Input Sulfur in LKD (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Hydrate Injection (%) {Kilns 1 & 2 only}]

Table 34. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Hydrate Injection - Incremental Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO$_2$ Emissions Difference (tpy)[1]	+663	+617	0	0	+1,279
Total Annualized Cost Difference	$ 5,848,549	$ 5,807,168	$ -	$ -	$ 11,655,717
Cost Effectiveness ($/ton reduced)	N/A	N/A	N/A	N/A	N/A

1. Compared to baseline SO$_2$ Emissions with Add-On Controls (Table 5).

Table 35. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Wet FGD Scrubber - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	36.4%	35.6%	38.4%	38.4%
Coke	54.6%	53.4%	57.6%	57.6%
Natural Gas	9.0%	11.0%	4.0%	4.0%

1. Baseline fuel mix.

Table 36. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Wet FGD Scrubber

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
Scubber Capital Cost[1]	$ 4,064,945	$ 3,866,945	$ -	$ -	$ 7,931,890
Pond Expansion Cost[2]	$ 1,000,000	$ 1,000,000	$ -	$ -	$ 2,000,000
Total Capital Investment[3]	$ 4,064,945	$ 3,866,945	$ -	$ -	$_ 7,931,890
Capital Recovery Factor[4]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[5]	$ 383,702	$ 365,012	$ -	$ -	$ 748,714
Annual Costs					
Direct Annual Costs					$ -
O&M Costs[1][6]	$ 211,377	$ 201,081	$ -	$ -	$ 412,458
Reagent Costs[6]	$ 1,314,000	$ 1,314,000	$ -	$ -	$ 2,628,000
Waste Disposal Costs[6]	$ 1,189,520	$ 1,189,520	$ -	$ -	$ 2,379,040
Indirect Annual Costs[7]					
Overhead	$ 915,226	$ 909,049	$ -	$ -	$ 1,824,275
Administrative Charges	$ 81,299	$ 77,339	$ -	$ -	$ 158,638
Property Tax	$ 40,649	$ 38,669	$ -	$ -	$ 79,319
Insurance	$ 40,649	$ 38,669	$ -	$ -	$ 79,319
Downtime Revenue Loss[8]	$ 676,224	$ 571,034	$ -	$ -	$ 1,247,258
Kiln Startup[9]	$ 140,250	$ 140,250	$ -	$ -	$ 280,500
Total Annualized Cost[10]	$ 4,992,897	$ 4,844,624	$ -	$ -	$ 9,837,521

1. Based on the Air Pollution Control Technology Fact Sheet for Flue Gas Desulfurization (2003). For capital cost, using minimum costs in terms of $/MMBtu/hr for Wet FGD Scrubbers with unit size < 4,000 MMBtu/hr to be conservative.
For O&M costs, using average costs in terms of $/MMBtu/hr for Wet FGD Scrubbers with unit size < 4,000 MMBtu/hr to be more representative. Converted from 2001 dollars to 2019 dollars.
2. Lhoist estimate for expansion of the water pond (required for scrubber water).
3. Total Capital Investment is equal to the sum of all capital costs.
4. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
5. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
6. Reagent and waste disposal costs assumed to be similar to hydrated lime based on April 2017 Final Report, Dry Sorbent Injection for SO2/HCl Control Cost Development Methodology, by Sargent & Lundy, LLC, funded by the U.S. EPA. Assumes 1 tph reagent usage rate.
7. Indirect Annual Costs based on EPA Air Pollution Control Cost Manual, Section 5.2, Chapter 1, Table 1.4.
8. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
9. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
10. Fuel costs are equivalent to baseline fuel costs and are not listed.
Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 37. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Wet FGD Scrubber - SO$_2$ Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	7.0	6.5	481	507	1,001
Coke (tpy)[1]	34	32.1	2,373	2,502	4,942
Natural Gas (tpy)[2]	4.41E-04	5.13E-04	1.28E-02	1.35E-02	2.73E-02
Total	41	38.5	2,854	3,008	5,942

1. Baseline SO2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber (%) {Kilns 1 & 2 only}]
2. Baseline SO2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton)* Molar Mass Ratio *
[100% - Input Sulfur in LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber (%) {Kilns 1 & 2 only}]

Table 38. Economic Analysis - Alternative Control Technologies - Kiln 1 & 2 Wet FGD Scrubber - Incremental Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO$_2$ Emissions Difference (tpy)[1]	-332	-309	0	0	-640
Total Annualized Cost Difference	$ 4,992,897	$ 4,844,624	$ -	$ -	$ 9,837,521
Cost Effectiveness ($/ton reduced)	$ 15,056	$ 15,702	N/A	N/A	$ 15,368

1. Compared to baseline SO$_2$ Emissions with Add-On Controls (Table 5).

Scenario 1A Table 1. Economic Analysis - Low Sulfur Coal - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	45.0%	45.0%	45.0%	45.0%
Coke	46.0%	46.0%	46.0%	46.0%
Natural Gas	9.0%	9.0%	9.0%	9.0%
Low Sulfur Coal	0.0%	0.0%	0.0%	0.0%

Scenario 1A Table 2. Economic Analysis - Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	N/A	N/A	N/A	N/A	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ 1,435,157	$ 1,365,252	$ 2,160,161	$ 2,277,170	$ 7,237,739
Coke	$ 971,982	$ 924,638	$ 1,463,003	$ 1,542,249	$ 4,901,872
Natural Gas	$ 358,085	$ 340,643	$ 538,980	$ 568,174	$ 1,805,881
Low Sulfur Coal	$ -	$ -	$ -	$ -	$ -
Downtime Revenue Loss[4]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[5]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[6]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[7]	$ 3,826,084	$ 3,560,436	$ 6,301,143	$ 6,477,393	$ 20,165,056

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
5. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
6. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
7. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Scenario 1A Table 3. Economic Analysis - Low Sulfur Coal - SO$_2$ Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	77.7	73.9	563	594	1,308
Coke (tpy)[1]	261	249	1,895	1,998	4,403
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	2.88E-02	3.04E-02	6.69E-02
Low Sulfur Coal (tpy)[1]	0.0	0.0	0.0	0.0	0
Total	339	323	2,459	2,592	5,712

1. Baseline SO$_2$ Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO$_2$ Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario 1A Table 4. Economic Analysis - Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO$_2$ Emissions Difference (tpy)	-34	-25	-395	-417	-871
Total Annualized Cost Difference	$ 1,153,416	$ 990,645	$ 2,386,326	$ 2,350,522	$ 6,880,909
Cost Effectiveness ($/ton reduced)	$ 33,901	$ 40,324	$ 6,036	$ 5,640	$ 7,903

Scenario 1B Table 1. Economic Analysis - Low Sulfur Coal - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	25.0%	25.0%	25.0%	25.0%
Coke	46.0%	46.0%	46.0%	46.0%
Natural Gas	9.0%	9.0%	9.0%	9.0%
Low Sulfur Coal	20.0%	20.0%	20.0%	20.0%

Scenario 1B Table 2. Economic Analysis - Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
Equipment for Additional Fuel[1]	$ 359,500	$ 359,500	$ 359,500	$ 359,500	$ 1,438,000
Total Capital Investment[2]	$ 359,500	$ 359,500	$ 359,500	$ 359,500	$ 1,438,000
Capital Recovery Factor[3]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[4]	$ 33,934	$ 33,934	$ 33,934	$ 33,934	$ 135,737
Annual Costs					
Coal	$ 797,309	$ 758,473	$ 1,200,089	$ 1,265,094	$ 4,020,966
Coke	$ 971,982	$ 924,638	$ 1,463,003	$ 1,542,249	$ 4,901,872
Natural Gas	$ 358,085	$ 340,643	$ 538,980	$ 568,174	$ 1,805,881
Low Sulfur Coal	$ 730,181	$ 694,615	$ 1,099,050	$ 1,158,582	$ 3,682,428
Downtime Revenue Loss[5]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[6]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[7]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[8]	$ 3,952,352	$ 3,682,207	$ 6,474,056	$ 6,657,833	$ 20,766,448

1. Lhoist estimate for equipment related to an additional solid fuel handling system such as additional hopper, additional screw(s), ramp, area for new low sulfur coal pile, additional shed, etc.
2. Total Capital Investment is equal to the sum of all capital costs.
3. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
4. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
5. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
6. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
7. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
8. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Scenario 1B Table 3. Economic Analysis - Low Sulfur Coal - SO_2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	43.1	41.0	313	330	727
Coke (tpy)[1]	261	249	1,895	1,998	4,403
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	2.88E-02	3.04E-02	6.69E-02
Low Sulfur Coal (tpy)[1]	20.2	19.2	147	154	340
Total	325	309	2,355	2,482	5,471

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario 1B Table 4. Economic Analysis - Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-48	-38	-499	-526	-1,112
Total Annualized Cost Difference	$ 1,279,684	$ 1,112,416	$ 2,559,238	$ 2,530,963	$ 7,482,301
Cost Effectiveness ($/ton reduced)	$ 26,479	$ 29,139	$ 5,128	$ 4,811	$ 6,730

Scenario 1C Table 1. Economic Analysis - Low Sulfur Coal - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	0.0%	0.0%	0.0%	0.0%
Coke	46.0%	46.0%	46.0%	46.0%
Natural Gas	9.0%	9.0%	9.0%	9.0%
Low Sulfur Coal	45.0%	45.0%	45.0%	45.0%

Scenario 1C Table 2. Economic Analysis - Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	N/A	N/A	N/A	N/A	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ -	$ -	$ -	$ -	$ -
Coke	$ 971,982	$ 924,638	$ 1,463,003	$ 1,542,249	$ 4,901,872
Natural Gas	$ 358,085	$ 340,643	$ 538,980	$ 568,174	$ 1,805,881
Low Sulfur Coal	$ 1,642,908	$ 1,562,883	$ 2,472,862	$ 2,606,809	$ 8,285,462
Downtime Revenue Loss[4]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[5]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[6]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[7]	$ 4,033,835	$ 3,758,068	$ 6,613,845	$ 6,807,032	$ 21,212,779

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
5. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
6. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
7. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Scenario 1C Table 3. Economic Analysis - Low Sulfur Coal - SO_2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	0.0	0.0	0.0	0.0	0.0
Coke (tpy)[1]	261	249	1,895	1,998	4,403
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	2.88E-02	3.04E-02	6.69E-02
Low Sulfur Coal (tpy)[1]	45.5	43.3	330	348	766
Total	307	292	2,225	2,346	5,169

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario 1C Table 4. Economic Analysis - Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-66	-55	-629	-663	-1,413
Total Annualized Cost Difference	$ 1,361,167	$ 1,188,277	$ 2,699,027	$ 2,680,162	$ 7,928,632
Cost Effectiveness ($/ton reduced)	$ 20,558	$ 21,532	$ 4,293	$ 4,044	$ 5,611

Scenario 2A Table 1. Economic Analysis - Low Sulfur Coal - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	60.0%	60.0%	60.0%	60.0%
Coke	31.0%	31.0%	31.0%	31.0%
Natural Gas	9.0%	9.0%	9.0%	9.0%
Low Sulfur Coal	0.0%	0.0%	0.0%	0.0%

Scenario 2A Table 2. Economic Analysis - Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	N/A	N/A	N/A	N/A	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ 1,913,543	$ 1,820,336	$ 2,880,215	$ 3,036,226	$ 9,650,319
Coke	$ 655,032	$ 623,126	$ 985,937	$ 1,039,342	$ 3,303,436
Natural Gas	$ 358,085	$ 340,643	$ 538,980	$ 568,174	$ 1,805,881
Low Sulfur Coal	$ -	$ -	$ -	$ -	$ -
Downtime Revenue Loss[4]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[5]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[6]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[7]	$ 3,987,519	$ 3,714,008	$ 6,544,131	$ 6,733,542	$ 20,979,200

1. Total Capital Investment is equal to the sum of all capital costs.

2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.

3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor

4. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.

5. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.

6. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.

7. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Scenario 2A Table 3. Economic Analysis - Low Sulfur Coal - SO_2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	104	98.5	751	792	1,744
Coke (tpy)[1]	176	168	1,277	1,346	2,967
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	2.88E-02	3.04E-02	6.69E-02
Low Sulfur Coal (tpy)[1]	0.0	0.0	0.0	0.0	0.0
Total	280	266	2,028	2,138	4,712

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario 2A Table 4. Economic Analysis - Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-93	-81	-826	-870	-1,870
Total Annualized Cost Difference	$ 1,314,851	$ 1,144,217	$ 2,629,313	$ 2,606,672	$ 7,695,052
Cost Effectiveness ($/ton reduced)	$ 14,083	$ 14,123	$ 3,184	$ 2,995	$ 4,114

Scenario 2B Table 1. Economic Analysis - Low Sulfur Coal - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	40.0%	40.0%	40.0%	40.0%
Coke	31.0%	31.0%	31.0%	31.0%
Natural Gas	9.0%	9.0%	9.0%	9.0%
Low Sulfur Coal	20.0%	20.0%	20.0%	20.0%

Scenario 2B Table 2. Economic Analysis - Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
Equipment for Additional Fuel[1]	$ 359,500	$ 359,500	$ 359,500	$ 359,500	$ 1,438,000
Total Capital Investment[2]	$ 359,500	$ 359,500	$ 359,500	$ 359,500	$ 1,438,000
Capital Recovery Factor[3]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[4]	$ 33,934	$ 33,934	$ 33,934	$ 33,934	$ 135,737
Annual Costs					
Coal	$ 1,275,695	$ 1,213,557	$ 1,920,143	$ 2,024,151	$ 6,433,546
Coke	$ 655,032	$ 623,126	$ 985,937	$ 1,039,342	$ 3,303,436
Natural Gas	$ 358,085	$ 340,643	$ 538,980	$ 568,174	$ 1,805,881
Low Sulfur Coal	$ 730,181	$ 694,615	$ 1,099,050	$ 1,158,582	$ 3,682,428
Downtime Revenue Loss[5]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[6]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[7]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[8]	$ 4,113,787	$ 3,835,778	$ 6,717,043	$ 6,913,983	$ 21,580,591

1. Lhoist estimate for equipment related to an additional solid fuel handling system such as additional hopper, additional screw(s), ramp, area for new low sulfur coal pile, additional shed, etc.
2. Total Capital Investment is equal to the sum of all capital costs.
3. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
4. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
5. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
6. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
7. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
8. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Scenario 2B Table 3. Economic Analysis - Low Sulfur Coal - SO_2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	69.0	65.7	501	528	1,163
Coke (tpy)[1]	176	168	1,277	1,346	2,967
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	2.88E-02	3.04E-02	6.69E-02
Low Sulfur Coal (tpy)[1]	20.2	19.2	147	154	340.5
Total	265	252	1,924	2,029	4,471

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario 2B Table 4. Economic Analysis - Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-108	-95	-929	-980	-2,111
Total Annualized Cost Difference	$ 1,441,119	$ 1,265,987	$ 2,802,226	$ 2,787,112	$ 8,296,444
Cost Effectiveness ($/ton reduced)	$ 13,384	$ 13,379	$ 3,015	$ 2,845	$ 3,929

Scenario 2C Table 1. Economic Analysis - Low Sulfur Coal - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	20.0%	20.0%	20.0%	20.0%
Coke	31.0%	31.0%	31.0%	31.0%
Natural Gas	9.0%	9.0%	9.0%	9.0%
Low Sulfur Coal	40.0%	40.0%	40.0%	40.0%

Scenario 2C Table 2. Economic Analysis - Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
Equipment for Additional Fuel[1]	$ 359,500	$ 359,500	$ 359,500	$ 359,500	$ 1,438,000
Total Capital Investment[2]	$ 359,500	$ 359,500	$ 359,500	$ 359,500	$ 1,438,000
Capital Recovery Factor[3]	0.09	0.09	0.09	0.09`	0.09
Annualized Capital Costs[4]	$ 33,934	$ 33,934	$ 33,934	$ 33,934	$ 135,737
Annual Costs					
Coal	$ 637,848	$ 606,779	$ 960,072	$ 1,012,075	$ 3,216,773
Coke	$ 655,032	$ 623,126	$ 985,937	$ 1,039,342	$ 3,303,436
Natural Gas	$ 358,085	$ 340,643	$ 538,980	$ 568,174	$ 1,805,881
Low Sulfur Coal	$ 1,460,362	$ 1,389,230	$ 2,198,100	$ 2,317,163	$ 7,364,855
Downtime Revenue Loss[5]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[6]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[7]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[8]	$ 4,206,120	$ 3,923,615	$ 6,856,022	$ 7,060,489	$ 22,046,246

1. Lhoist estimate for equipment related to an additional solid fuel handling system such as additional hopper, additional screw(s), ramp, area for new low sulfur coal pile, additional shed, etc. ·
2. Total Capital Investment is equal to the sum of all capital costs.
3. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
4. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
5. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
6. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
7. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
8. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Scenario 2C Table 3. Economic Analysis - Low Sulfur Coal - SO_2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]·	34.5	32.8	250	264	581
Coke (tpy)[1]	176	168	1,277	1,346	2,967
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	2.88E-02	3.04E-02	6.69E-02
Low Sulfur Coal (tpy)[1]	40.4	38.4	·293	309	680.9
Total	251	238.8	1,821	1,919	4,230

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *   ·
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario 2C Table 4. Economic Analysis - Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-122	-108	-1,033	-1,089	-2,353
Total Annualized Cost Difference	$ 1,533,452	$ 1,353,824	$ 2,941,204	$ 2,933,619	$ 8,762,099
Cost Effectiveness ($/ton reduced)	$ 12,572	$ 12,508	$ 2,847	$ 2,694	$ 3,725

Scenario 2D Table 1. Economic Analysis - Low Sulfur Coal - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	0.0%	0.0%	0.0%	0.0%
Coke	31.0%	31.0%	31.0%	31.0%
Natural Gas	9.0%	9.0%	9.0%	9.0%
Low Sulfur Coal	60.0%	60.0%	60.0%	60.0%

Scenario 2D Table 2. Economic Analysis - Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	N/A	N/A	N/A	N/A	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ -	$ -	$ -	$ -	$ -
Coke	$ 655,032	$ 623,126	$ 985,937	$ 1,039,342	$ 3,303,436
Natural Gas	$ 358,085	$ 340,643	$ 538,980	$ 568,174	$ 1,805,881
Low Sulfur Coal	$ 2,190,544	$ 2,083,844	$ 3,297,149	$ 3,475,745	$ 11,047,283
Downtime Revenue Loss[4]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[5]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[6]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[7]	$ 4,264,520	$ 3,977,517	$ 6,961,066	$ 7,173,061	$ 22,376,163

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
5. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
6. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
7. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Scenario 2D Table 3. Economic Analysis - Low Sulfur Coal - SO$_2$ Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	0.0	0.0	0.0	0.0	0
Coke (tpy)[1]	176	168	1,277	1,346	2,967
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	2.88E-02	3.04E-02	6.69E-02
Low Sulfur Coal (tpy)[1]	60.6	57.7	440	463	1,021.4
Total	237	225	1,717	1,810	3,989

1. Baseline SO$_2$ Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO$_2$ Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario 2D Table 4. Economic Analysis - Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO$_2$ Emissions Difference (tpy)	-136	-122	-1,137	-1,198	-2,594
Total Annualized Cost Difference	$ 1,591,852	$ 1,407,726	$ 3,046,248	$ 3,046,191	$ 9,092,016
Cost Effectiveness ($/ton reduced)	$ 11,681	$ 11,553	$ 2,679	$ 2,542	$ 3,506

Scenario 3A Table 1. Economic Analysis - Low Sulfur Coal - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	75.0%	75.0%	75.0%	75.0%
Coke	16.0%	16.0%	16.0%	16.0%
Natural Gas	9.0%	9.0%	9.0%	9.0%
Low Sulfur Coal	0.0%	0.0%	0.0%	0.0%

Scenario 3A Table 2. Economic Analysis - Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	N/A	N/A	N/A	N/A	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ 2,391,928	$ 2,275,419	$ 3,600,268	$ 3,795,283	$ 12,062,899
Coke	$ 338,081	$ 321,613	$ 508,871	$ 536,434	$ 1,704,999
Natural Gas	$ 358,085	$ 340,643	$ 538,980	$ 568,174	$ 1,805,881
Low Sulfur Coal	$ -	$ -	$ -	$ -	$ -
Downtime Revenue Loss[4]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[5]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[6]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[7]	$ 4,148,954	$ 3,867,579	$ 6,787,118	$ 6,989,691	$ 21,793,343

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
5. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
6. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
7. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Scenario 3A Table 3. Economic Analysis - Low Sulfur Coal - SO$_2$ Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	129	123	939	989	2,180
Coke (tpy)[1]	91	86	659	695	1,532
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	2.88E-02	3.04E-02	6.69E-02
Low Sulfur Coal (tpy)[1]	0.0	0.0	0.0	0.0	0.0
Total	220	210	1,598	1,684	3,712

1. Baseline SO$_2$ Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO$_2$ Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario 3A Table 4. Economic Analysis - Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO$_2$ Emissions Difference (tpy)	-153	-137	-1,256	-1,324	-2,870
Total Annualized Cost Difference	$ 1,476,286	$ 1,297,788	$ 2,872,301	$ 2,862,821	$ 8,509,196
Cost Effectiveness ($/ton reduced)	$ 9,667	$ 9,440	$ 2,287	$ 2,162	$ 2,965

Scenario 3B Table 1. Economic Analysis - Low Sulfur Coal - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	55.0%	55.0%	55.0%	55.0%
Coke	16.0%	16.0%	16.0%	16.0%
Natural Gas	9.0%	9.0%	9.0%	9.0%
Low Sulfur Coal	20.0%	20.0%	20.0%	20.0%

Scenario 3B Table 2. Economic Analysis - Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
Equipment for Additional Fuel[1]	$ 359,500	$ 359,500	$ 359,500	$ 359,500	$ 1,438,000
Total Capital Investment[2]	$ 359,500	$ 359,500	$ 359,500	$ 359,500	$ 1,438,000
Capital Recovery Factor[3]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[4]	$ 33,934	$ 33,934	$ 33,934	$ 33,934	$ 135,737
Annual Costs					
Coal	$ 1,754,081	$ 1,668,641	$ 2,640,197	$ 2,783,207	$ 8,846,126
Coke	$ 338,081	$ 321,613	$ 508,871	$ 536,434	$ 1,704,999
Natural Gas	$ 358,085	$ 340,643	$ 538,980	$ 568,174	$ 1,805,881
Low Sulfur Coal	$ 730,181	$ 694,615	$ 1,099,050	$ 1,158,582	$ 3,682,428
Downtime Revenue Loss[5]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[6]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[7]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[8]	$ 4,275,222	$ 3,989,350	$ 6,960,031	$ 7,170,132	$ 22,394,734

1. Lhoist estimate for equipment related to an additional solid fuel handling system such as additional hopper, additional screw(s), ramp, area for new low sulfur coal pile, additional shed, etc.
2. Total Capital Investment is equal to the sum of all capital costs.
3. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
4. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
5. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
6. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
7. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
8. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Scenario 3B Table 3. Economic Analysis - Low Sulfur Coal - SO2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	94.9	90.3	688	726	1,599
Coke (tpy)[1]	91	86	659	695	1,532
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	2.88E-02	3.04E-02	6.69E-02
Low Sulfur Coal (tpy)[1]	20.2	19.2	147	154	340.5
Total	206	196	1,494	1,575	3,471

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario 3B Table 4. Economic Analysis - Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-167	-151	-1,360	-1,433	-3,111
Total Annualized Cost Difference	$ 1,602,554	$ 1,419,559	$ 3,045,213	$ 3,043,262	$ 9,110,587
Cost Effectiveness ($/ton reduced)	$ 9,595	$ 9,396	$ 2,240	$ 2,123	$ 2,928

Scenario 3C Table 1. Economic Analysis - Low Sulfur Coal - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	35.0%	35.0%	35.0%	35.0%
Coke	16.0%	16.0%	16.0%	16.0%
Natural Gas	9.0%	9.0%	9.0%	9.0%
Low Sulfur Coal	40.0%	40.0%	40.0%	40.0%

Scenario 3C Table 2. Economic Analysis - Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
Equipment for Additional Fuel[1]	$ 359,500	$ 359,500	$ 359,500	$ 359,500	$ 1,438,000
Total Capital Investment[2]	$ 359,500	$ 359,500	$ 359,500	$ 359,500	$ 1,438,000
Capital Recovery Factor[3]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[4]	$ 33,934	$ 33,934	$ 33,934	$ 33,934	$ 135,737
Annual Costs					
Coal	$ 1,116,233	$ 1,061,862	$ 1,680,125	$ 1,771,132	$ 5,629,353
Coke	$ 338,081	$ 321,613	$ 508,871	$ 536,434	$ 1,704,999
Natural Gas	$ 358,085	$ 340,643	$ 538,980	$ 568,174	$ 1,805,881
Low Sulfur Coal	$ 1,460,362	$ 1,389,230	$ 2,198,100	$ 2,317,163	$ 7,364,855
Downtime Revenue Loss[5]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[6]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[7]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[8]	$ 4,367,555	$ 4,077,186	$ 7,099,009	$ 7,316,638	$ 22,860,389

1. Lhoist estimate for equipment related to an additional solid fuel handling system such as additional hopper, additional screw(s), ramp, area for new low sulfur coal pile, additional shed, etc.
2. Total Capital Investment is equal to the sum of all capital costs.
3. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
4. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
5. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
6. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
7. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
8. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs.

Scenario 3C Table 3. Economic Analysis - Low Sulfur Coal - SO2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	60.4	57.5	438	462	1,018
Coke (tpy)[1]	91	86	659	695	1,532
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	2.88E-02	3.04E-02	6.69E-02
Low Sulfur Coal (tpy)[1]	40.4	38.4	293	309	680.9
Total	192	182	1,390	1,466	3,230

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario 3C Table 4. Economic Analysis - Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-181	-165	-1,464	-1,543	-3,352
Total Annualized Cost Difference	$ 1,694,887	$ 1,507,395	$ 3,184,191	$ 3,189,768	$ 9,576,242
Cost Effectiveness ($/ton reduced)	$ 9,348	$ 9,153	$ 2,176	$ 2,068	$ 2,857

Scenario 3D Table 1. Economic Analysis - Low Sulfur Coal - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	15.0%	15.0%	15.0%	15.0%
Coke	16.0%	16.0%	16.0%	16.0%
Natural Gas	9.0%	9.0%	9.0%	9.0%
Low Sulfur Coal	60.0%	60.0%	60.0%	60.0%

Scenario 3D Table 2. Economic Analysis - Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
Equipment for Additional Fuel[1]	$ 359,500	$ 359,500	$ 359,500	$ 359,500	$ 1,438,000
Total Capital Investment[2]	$ 359,500	$ 359,500	$ 359,500	$ 359,500	$ 1,438,000
Capital Recovery Factor[3]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[4]	$ 33,934	$ 33,934	$ 33,934	$ 33,934	$ 135,737
Annual Costs					
Coal	$ 478,386	$ 455,084	$ 720,054	$ 759,057	$ 2,412,580
Coke	$ 338,081	$ 321,613	$ 508,871	$ 536,434	$ 1,704,999
Natural Gas	$ 358,085	$ 340,643	$ 538,980	$ 568,174	$ 1,805,881
Low Sulfur Coal	$ 2,190,544	$ 2,083,844	$ 3,297,149	$ 3,475,745	$ 11,047,283
Downtime Revenue Loss[5]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[6]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[7]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[8]	$ 4,459,889	$ 4,165,022	$ 7,237,988	$ 7,463,145	$ 23,326,043

1. Lhoist estimate for equipment related to an additional solid fuel handling system such as additional hopper, additional screw(s), ramp, area for new low sulfur coal pile, additional shed, etc.
2. Total Capital Investment is equal to the sum of all capital costs.
3. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
4. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
5. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
6. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
7. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
8. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Scenario 3D Table 3. Economic Analysis - Low Sulfur Coal - SO2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	25.9	24.6	188	198	436
Coke (tpy)[1]	91	86	659	695	1,532
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	2.88E-02	3.04E-02	6.69E-02
Low Sulfur Coal (tpy)[1]	60.6	57.7	440	463	1,021.4
Total	177	169	1,287	1,356	2,989

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario 3D Table 4. Economic Analysis - Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-196	-178	-1,567	-1,652	-3,593
Total Annualized Cost Difference	$ 1,787,221	$ 1,595,231	$ 3,323,170	$ 3,336,274	$ 10,041,896
Cost Effectiveness ($/ton reduced)	$ 9,136	$ 8,947	$ 2,120	$ 2,019	$ 2,795

Scenario 3E Table 1. Economic Analysis - Low Sulfur Coal - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	0.0%	0.0%	0.0%	0.0%
Coke	16.0%	16.0%	16.0%	16.0%
Natural Gas	9.0%	9.0%	9.0%	9.0%
Low Sulfur Coal	75.0%	75.0%	75.0%	75.0%

Scenario 3E Table 2. Economic Analysis - Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	N/A	N/A	N/A	N/A	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ -	$ -	$ -	$ -	$ -
Coke	$ 338,081	$ 321,613	$ 508,871	$ 536,434	$ 1,704,999
Natural Gas	$ 358,085	$ 340,643	$ 538,980	$ 568,174	$ 1,805,881
Low Sulfur Coal	$ 2,738,180	$ 2,604,805	$ 4,121,437	$ 4,344,681	$ 13,809,103
Downtime Revenue Loss[4]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[5]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[6]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[7]	$ 4,495,205	$ 4,196,965	$ 7,308,287	$ 7,539,090	$ 23,539,547

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
5. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
6. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
7. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Scenario 3E Table 3. Economic Analysis - Low Sulfur Coal - SO2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	0.0	0.0	0.0	0.0	0
Coke (tpy)[1]	91	86	659	695	1,532
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	2.88E-02	3.04E-02	6.69E-02
Low Sulfur Coal (tpy)[1]	75.8	72.1	550	579	1,276.7
Total	167	159	1,209	1,274	2,808

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario 3E Table 4. Economic Analysis - Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-206	-189	-1,645	-1,734	-3,774
Total Annualized Cost Difference	$ 1,822,537	$ 1,627,174	$ 3,393,469	$ 3,412,220	$ 10,255,400
Cost Effectiveness ($/ton reduced)	$ 8,832	$ 8,632	$ 2,063	$ 1,968	$ 2,717

ADEM1 Scenario Table 1. Economic Analysis - Low Sulfur Coal - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	0.0%	0.0%	0.0%	0.0%
Coke	18.2%	18.2%	19.0%	19.0%
Natural Gas	9.0%	9.0%	5.0%	5.0%
Low Sulfur Coal	72.8%	72.8%	76.0%	76.0%

ADEM1 Scenario Table 2. Economic Analysis - Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	N/A	N/A	N/A	N/A	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ -	$ -	$ -	$ -	$ -
Coke	$ 384,567	$ 365,835	$ 604,284	$ 637,016	$ 1,991,702
Natural Gas	$ 358,085	$ 340,643	$ 299,433	$ 315,652	$ 1,313,813
Low Sulfur Coal	$ 2,657,860	$ 2,528,398	$ 4,176,389	$ 4,402,610	$ 13,765,257
Downtime Revenue Loss[4]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[5]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[6]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[7]	$ 4,461,371	$ 4,164,779	$ 7,219,106	$ 7,445,079	$ 23,290,336

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
5. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
6. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
7. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

ADEM1 Scenario Table 3. Economic Analysis - Low Sulfur Coal - SO2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	0.0	0.0	0.0	0.0	0
Coke (tpy)[1]	103	98.4	783	825	1,810
Natural Gas (tpy)[2]	3.97E-03	3.78E-03	1.60E-02	1.69E-02	4.06E-02
Low Sulfur Coal (tpy)[1]	73.6	70.0	557	587	1,287.4
Total	177	168	1,340	1,412	3,097

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

ADEM1 Scenario Table 4. Economic Analysis - Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-196	-179	-1,514	-1,596	-3,485
Total Annualized Cost Difference	$ 1,788,703	$ 1,594,988	$ 3,304,288	$ 3,318,208	$ 10,006,188
Cost Effectiveness ($/ton reduced)	$ 9,123	$ 8,924	$ 2,182	$ 2,079	$ 2,871

ADEM2 Scenario Table 1. Economic Analysis - Low Sulfur Coal - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	0.0%	0.0%	0.0%	0.0%
Coke	54.6%	53.4%	57.6%	57.6%
Natural Gas	9.0%	11.0%	4.0%	4.0%
Low Sulfur Coal	36.4%	35.6%	38.4%	38.4%

ADEM2 Scenario Table 2. Economic Analysis - Low Sulfur Coal

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	N/A	N/A	N/A	N/A	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ -	$ -	$ -	$ -	$ -
Coke	$ 1,153,701	$ 1,073,384	$ 1,831,934	$ 1,931,164	$ 5,990,183
Natural Gas	$ 358,085	$ 416,341	$ 239,546	$ 252,522	$ 1,266,494
Low Sulfur Coal	$ 1,328,930	$ 1,236,414	$ 2,110,176	$ 2,224,477	$ 6,899,997
Downtime Revenue Loss[4]	$ 841,860	$ 710,904	$ 1,884,000	$ 1,870,800	$ 5,307,564
Kiln Startup[5]	$ 132,000	$ 132,000	$ 168,000	$ 132,000	$ 564,000
Ash Ring Cleanup[6]	$ 87,000	$ 87,000	$ 87,000	$ 87,000	$ 348,000
Total Annualized Cost[7]	$ 3,901,575	$ 3,656,043	$ 6,320,656	$ 6,497,962	$ 20,376,237

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Based on Lhoist estimates for revenue loss associated with increased kiln downtime caused by this scenario.
5. Based on Lhoist estimates for additional start up costs following kiln downtime caused by this scenario.
6. Based on Lhoist estimates for ash ring cleanup costs caused by this scenario.
7. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

ADEM2 Scenario Table 3. Economic Analysis - Low Sulfur Coal - SO2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	0.0	0.0	0.0	0.0	0
Coke (tpy)[1]	310	289	2,373	2,502	5,474
Natural Gas (tpy)[2]	3.97E-03	4.62E-03	1.28E-02	1.35E-02	3.49E-02
Low Sulfur Coal (tpy)[1]	36.8	34.2	281	297	649.0
Total	347	323	2,655	2,798	6,123

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

ADEM2 Scenario Table 4. Economic Analysis - Low Sulfur Coal - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-26	-24	-199	-210	-459
Total Annualized Cost Difference	$ 1,228,907	$ 1,086,252	$ 2,405,838	$ 2,371,092	$ 7,092,090
Cost Effectiveness ($/ton reduced)	$ 47,201	$ 44,844	$ 12,079	$ 11,293	$ 15,438

Scenario NG1 Table 1. Economic Analysis - Natural Gas - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	25.0%	25.0%	25.0%	25.0%
Coke	35.0%	35.0%	35.0%	35.0%
Natural Gas	40.0%	40.0%	40.0%	40.0%
Low Sulfur Coal	0.0%	0.0%	0.0%	0.0%

Scenario NG1 Table 2. Economic Analysis - Natural Gas

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
New Burners[1]	$ 365,000	$ 365,000	$ 365,000	$ 365,000	$ 1,460,000
Natural Gas Plant Supply Lines[1]	$ 152,640	$ 152,640	$ 178,080	$ 178,080	$ 661,440
Kiln Downtime for Install[1]	$ 371,260	$ 313,509	$ 844,032	$ 825,023	$ 2,353,824
Total Capital Investment[2]	$ 888,900	$ 831,149	$ 1,387,112	$ 1,368,103	$ 4,475,264
Capital Recovery Factor[3]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[4]	$ 83,906	$ 78,455	$ 130,934	$ 129,139	$ 422,433
Annual Costs					
Coal	$ 797,309	$ 758,473	$ 1,200,089	$ 1,265,094	$ 4,020,966
Coke	$ 739,552	$ 703,529	$ 1,113,154	$ 1,173,450	$ 3,729,685
Natural Gas	$ 1,591,487	$ 1,513,967	$ 2,395,465	$ 2,525,219	$ 8,026,138
Low Sulfur Coal	$ -	$ -	$ -	$ -	$ -
Total Annualized Cost[5]	$ 3,212,254	$ 3,054,424	$ 4,839,642	$ 5,092,903	$ 16,199,223

1. Based on quotes and Lhoist estimates.
2. Total Capital Investment is equal to the sum of all capital costs.
3. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
4. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
5. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Scenario NG1 Table 3. Economic Analysis - Natural Gas - SO2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	43.1	41.0	313	330	727
Coke (tpy)[1]	199	189	1,442	1,520	3,350
Natural Gas (tpy)[2]	1.77E-02	1.68E-02	1.28E-01	1.35E-01	2.97E-01
Low Sulfur Coal (tpy)[1]	0.0	0.0	0.0	0.0	0.0
Total	242	230	1,755	1,850	4,078

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario NG1 Table 4. Economic Analysis - Natural Gas - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-131	-117	-1,099	-1,158	-2,505
Total Annualized Cost Difference	$ 539,586	$ 484,633	$ 924,824	$ 966,033	$ 2,915,076
Cost Effectiveness ($/ton reduced)	$ 4,118	$ 4,148	$ 842	$ 834	$ 1,164

Scenario NG2 Table 1. Economic Analysis - Natural Gas - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	20.0%	20.0%	20.0%	20.0%
Coke	20.0%	20.0%	20.0%	20.0%
Natural Gas	60.0%	60.0%	60.0%	60.0%
Low Sulfur Coal	0.0%	0.0%	0.0%	0.0%

Scenario NG2 Table 2. Economic Analysis - Natural Gas

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
New Burners[1]	$ 365,000	$ 365,000	$ 365,000	$ 365,000	$ 1,460,000
Natural Gas Plant Supply Lines[1]	$ 152,640	$ 152,640	$ 178,080	$ 178,080	$ 661,440
Kiln Downtime for Install[1]	$ 371,260	$ 313,509	$ 844,032	$ 825,023	$ 2,353,824
Total Capital Investment[2]	$ 888,900	$ 831,149	$ 1,387,112	$ 1,368,103	$ 4,475,264
Capital Recovery Factor[3]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[4]	$ 83,906	$ 78,455	$ 130,934	$ 129,139	$ 422,433
Annual Costs					
Coal	$ 637,848	$ 606,779	$ 960,072	$ 1,012,075	$ 3,216,773
Coke	$ 422,601	$ 402,017	$ 636,088	$ 670,543	$ 2,131,249
Natural Gas	$ 2,387,231	$ 2,270,951	$ 3,593,197	$ 3,787,829	$ 12,039,208
Low Sulfur Coal	$ -	$ -	$ -	$ -	$ -
Total Annualized Cost[5]	$ 3,531,585	$ 3,358,200	$ 5,320,291	$ 5,599,587	$ 17,809,663

1. Based on quotes and Lhoist estimates.
2. Total Capital Investment is equal to the sum of all capital costs.
3. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
4. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
5. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Scenario NG2 Table 3. Economic Analysis - Natural Gas - SO2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	34.5	32.8	250	264	581
Coke (tpy)[1]	114	108	824	869	1,915
Natural Gas (tpy)[2]	2.65E-02	2.52E-02	1.92E-01	2.02E-01	4.46E-01
Low Sulfur Coal (tpy)[1]	0.0	0.0	0.0	0.0	0.0
Total	148	141	1,075	1,133	2,496

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario NG2 Table 4. Economic Analysis - Natural Gas - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-225	-206	-1,779	-1,876	-4,086
Total Annualized Cost Difference	$ 858,917	$ 788,409	$ 1,405,473	$ 1,472,716	$ 4,525,515
Cost Effectiveness ($/ton reduced)	$ 3,820	$ 3,825	$ 790	$ 785	$ 1,108

Scenario NG3 Table 1. Economic Analysis - Natural Gas - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	10.0%	10.0%	10.0%	10.0%
Coke	10.0%	10.0%	10.0%	10.0%
Natural Gas	80.0%	80.0%	80.0%	80.0%
Low Sulfur Coal	0.0%	0.0%	0.0%	0.0%

Scenario NG3 Table 2. Economic Analysis - Natural Gas

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
New Burners[1]	$ 365,000	$ 365,000	$ 365,000	$ 365,000	$ 1,460,000
Natural Gas Plant Supply Lines[1]	$ 152,640	$ 152,640	$ 178,080	$ 178,080	$ 661,440
Kiln Downtime for Install[1]	$ 371,260	$ 313,509	$ 844,032	$ 825,023	$ 2,353,824
Total Capital Investment[2]	$ 888,900	$ 831,149	$ 1,387,112	$ 1,368,103	$ 4,475,264
Capital Recovery Factor[3]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[4]	$ 83,906	$ 78,455	$ 130,934	$ 129,139	$ 422,433
Annual Costs					
Coal	$ 318,924	$ 303,389	$ 480,036	$ 506,038	$ 1,608,386
Coke	$ 211,301	$ 201,008	$ 318,044	$ 335,271	$ 1,065,624
Natural Gas	$ 3,182,974	$ 3,027,934	$ 4,790,930	$ 5,050,439	$ 16,052,277
Low Sulfur Coal	$ -	$ -	$ -	$ -	$ -
Total Annualized Cost[5]	$ 3,797,104	$ 3,610,786	$ 5,719,943	$ 6,020,887	$ 19,148,721

1. Based on quotes and Lhoist estimates.
2. Total Capital Investment is equal to the sum of all capital costs.
3. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
4. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
5. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Scenario NG3 Table 3. Economic Analysis - Natural Gas - SO2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	17.3	16.4	125	132	291
Coke (tpy)[1]	57	54.1	412	434	957
Natural Gas (tpy)[2]	3.53E-02	3.36E-02	2.56E-01	2.70E-01	5.95E-01
Low Sulfur Coal (tpy)[1]	0.0	0.0	0.0	0.0	0.0
Total	74.1	70.5	537	567	1,249

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario NG3 Table 4. Economic Analysis - Natural Gas - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-299	-277	-2,316	-2,442	-5,334
Total Annualized Cost Difference	$ 1,124,436	$ 1,040,995	$ 1,805,126	$ 1,894,017	$ 5,864,574
Cost Effectiveness ($/ton reduced)	$ 3,761	$ 3,764	$ 779	$ 776	$ 1,099

Scenario NG4 Table 1. Economic Analysis - Natural Gas - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	0.0%	0.0%	0.0%	0.0%
Coke	0.0%	0.0%	0.0%	0.0%
Natural Gas	100.0%	100.0%	100.0%	100.0%
Low Sulfur Coal	0.0%	0.0%	0.0%	0.0%

Scenario NG4 Table 2. Economic Analysis - Natural Gas

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
New Burners[1]	$ 365,000	$ 365,000	$ 365,000	$ 365,000	$ 1,460,000
Natural Gas Plant Supply Lines[1]	$ 152,640	$ 152,640	$ 178,080	$ 178,080	$ 661,440
Kiln Downtime for Install[1]	$ 371,260	$ 313,509	$ 844,032	$ 825,023	$ 2,353,824
Total Capital Investment[2]	$ 888,900	$ 831,149	$ 1,387,112	$ 1,368,103	$ 4,475,264
Capital Recovery Factor[3]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[4]	$ 83,906	$ 78,455	$ 130,934	$ 129,139	$ 422,433
Annual Costs					
Coal	$ --	$ -	$ -	$ -	$ -
Coke	$ -	$ -	$ -	$ -	$ -
Natural Gas	$ 3,978,718	$ 3,784,918	$ 5,988,662	$ 6,313,048	$ 20,065,346
Low Sulfur Coal	$ -	$ -	$ -	$ -	$ -
Total Annualized Cost[5]	$ 4,062,623	$ 3,863,372	$ 6,119,596	$ 6,442,187	$ 20,487,779

1. Based on quotes and Lhoist estimates.
2. Total Capital Investment is equal to the sum of all capital costs.
3. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
4. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
5. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Scenario NG4 Table 3. Economic Analysis - Natural Gas - SO2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	0.0	0.0	0.0	0.0	0
Coke (tpy)[1]	0.0	0.0	0.0	0.0	0
Natural Gas (tpy)[2]	4.41E-02	4.20E-02	3.20E-01	3.37E-01	7.44E-01
Low Sulfur Coal (tpy)[1]	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.3	0.3	0.7

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

Scenario NG4 Table 4. Economic Analysis - Natural Gas - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO₂ Emissions Difference (tpy)	-373	-347	-2,854	-3,008	-6,582
Total Annualized Cost Difference	$ 1,389,955	$ 1,293,581	$ 2,204,778	$ 2,315,317	$ 7,203,632
Cost Effectiveness ($/ton reduced)	$ 3,726	$ 3,728	$ 773	$ 770	$ 1,094

ATTACHMENT 2

Documentation from Spire

spire ⟨⟩

Spire Inc.
273 Cahaba Valley Parkway N
Pelham, Al 35124

March 12, 2021

Michael Will
Lhoist North America
7444 Hwy 25
Calera, Al 35040

Dear Michael,

Thank you for inquiring about increasing your natural gas usage in order to reduce the use of coal at your Lhoist Montevallo plant. Lhoist's current total connective load is 330 MMBtu per hour and is served on an interruptible basis. You have indicated that you would need approximately 1000 MMBtu per hour to operate the kilns on 100% natural gas. Unfortunately, Spire does not have the capacity to serve any additional load for the faciality beyond the 330 MMBtu/hr currently provided, but is working on a solution for future additional capacity.

Sincerely,

Craig Carter
LCI Business Development Representative

Appendix G-1f

Lhoist Montevallo Four Factor Analysis Addendum #2 - May 18, 2021

May 18, 2021

Mr. Skyler Sanderson
Environmental Engineering Specialist, Senior
Air Division, Energy Branch
Alabama Department of Environmental Management
1400 Coliseum Boulevard
Montgomery, AL 36110-2400
(334) 270 - 5647
skyler.sanderson@adem.alabama.gov

RE: Lhoist North America of Alabama, LLC - Montevallo Plant
   Regional Haze Rule – Four-Factor Analysis Additional Information Request Dated April 14, 2021

Dear Mr. Sanderson:

Lhoist North America of Alabama, LLC (LNA) owns and operates the Montevallo Plant, comprising of a lime manufacturing facility located in Calera, Shelby County, Alabama operating under Title V Major Source Operating Permit No. 411-0008 issued by the Alabama Department of Environmental Management (ADEM). LNA is submitting this letter in response to the ADEM additional information request letter, dated April 14, 2021, requesting additional information following submittal by LNA of the Four-Factor Analysis for the Montevallo Plant on February 5, 2021, and additional subsequently requested information on March 30, 2021.

The key items of concern addressed in this letter are as follows:

- Additional requested information regarding an additional fuel scenario involving higher usage rates of natural gas on Kilns 3 and 4, rather than an even distribution (20%) per kiln. So, for this updated evaluation Kilns 1 and 2 were not updated (kept at current long-term natural gas usage levels) and usage of natural gas on Kilns 3 and 4 was maximized.
- Providing additional alternative fuel scenarios data for the 100% natural gas case, including additional costs as requested in the letter from ADEM dated April 14, 2021.

Supporting documentation for this submittal is included in the two attachments to this letter.

- Attachment 1 - Updated detailed economic analysis documentation, including the additional requested analyses as outlined above.
- Attachment 2 - Documentation from the LNA natural gas provider (Spire), detailing the maximum amount of natural gas that the supplier can physically provide to the facility without natural gas transmission infrastructure projects for the Shelby County area. Also attached is a follow up e-mail from Spire discussing development plans for additional gas supply for the facility.

One point to address before progressing further, is the comment made by ADEM as follows within the letter dated April 14, 2021.

That level of emissions, plus the proximity to the Sipsey, means that L-M is the only facility in the State which ADEM has determined to have a significant negative impact on visibility in this protected area.

It is LNA's contention that this has still not been demonstrated. As outlined in the initial four factor analysis submitted on February 5, 2021, LNA was erroneously left out of the refined specific source apportionment modeling (PSAT) conducted by VISTAS to evaluate source impacts and evaluate if a four factor analysis was warranted for those sites. ADEM's current contention, with lack of other available documentation, is that a corrected AOI screening value would have resulted in a screening value of 2.69% sulfate contribution to Sipsey, and since that screening value was greater than the 1% threshold for refined PSAT modeling, ADEM states that LNA is having a significant negative impact on visibility to the Sipsey Class I Area.

This is an arbitrary and very conservative determination, as it is applying a screening step value to a refined modeling threshold. There is no direct evidence that if LNA was included within the PSAT modeling, as should have been done originally, that LNA impacts would have been greater than 1% sulfate contribution at Sipsey (thus requiring a 4-factor analysis). Refined PSAT modeling results generally decreased for all sources when compared to screening result values, as demonstrated in the February 5, 2021 four factor analysis submittal. For example, the TVA Cumberland Fossil Plant AOI screening step value of 3.18%, had PSAT modeling results of 1.48% sulfate contribution, a decrease of 1.70% from the screening step.

There is also a question regarding the actual long term SO_2 emissions from the site, particularly from Kilns 3 and 4. ADEM has recently required of LNA, per a letter dated April 27, 2021, to install SO_2 CEMS on Kilns 3 and 4 no later than January 1, 2022. If emissions from Kilns 3 and 4 are more in line with current emission estimates (e.g. approximately 6,000 tpy vs.9000 tpy), then AOI screening step results would have been less than 2% thus completely removing LNA from consideration for a four factor analysis as part of this planning period.

ADDITIONAL KILN 3 AND 4 INCREASED NATURAL GAS USAGE ANALYSES

Additional alternative fuel scenarios with use of increased natural gas usage on Kilns 3 and 4 (up to current supply capacity), while keeping Kilns 1 and 2 at their current long-term capacity, was conducted. A summary of the results of this new analysis is shown below in Table 1, with additional details for the analysis provided in Attachment 1 (labeled ADEM3 Scenario).

Table 1: Additional Kiln 3 and Kiln 4 Natural Gas Increased Usage Analyses

	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-707	-745	-1,452
Total Annualized Cost Difference	$ 689,364	$ 715,185	$ 1,404,549
Cost Effectiveness ($/ton reduced)	$ 976	$ 960	$ 968

1. Kilns 1 and 2 are unchanged from the baseline and are therefore excluded from the ADEM3 Scenario analysis.

After consideration of the total available natural gas supply (330 MMBtu/hr), needs for Kiln 5 (100 MMBtu/hr), facility dryer (20 MMBtu/hr), and reserve gas for current usage for Kilns 1 and 2 (~75 MMBtu/hr total for both kilns), the total gas that could be supplied to Kilns 3 and 4 can be estimated. Kilns 1 and 2 require continuous natural gas for operation of coal mill preheaters and flame shaping on each kiln. Kilns 1 and 2 also would need natural gas for any startup. This leaves the following.

[330 MMBtu/hr – 100 MMBtu/hr (Kiln 5 capacity) – 20 MMBtu/hr (Limestone Dryer) – 75 MMBtu/hr (current Kiln 1 and 2 usage)] / 2 kilns = 67.5 MMBtu/hr per Kiln

This works out to about 27% of the fuel usage to meet the expected fuel usage and annual MMBtu/yr needs of Kilns 3 and 4.

ADDITIONAL 100% NATURAL GAS USAGE ANALYSES

An additional 100% natural gas usage scenario was evaluated as requested. A summary of the results of this new analysis is shown below in Table 2, with additional details for the analysis provided in Attachment 1 (labeled ADEM4 Scenario).

Table 2: Additional Kiln 3 and Kiln 4 Natural Gas Increased Usage Analyses

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO$_2$ Emissions Difference (tpy)	-373	-347	-2,854	-3,008	-6,582
Total Annualized Cost Difference	$ 1,071,082	$ 946,410	$ 1,855,635	$ 1,981,233	$ 5,854,360
Cost Effectiveness ($/ton reduced)	$ 2,872	$ 2,727	$ 650	$ 659	$ 889

Results are similar to the previously provided NG4 scenario, with some reduction in the $/ton values given addition of other negative costs (decreased costs from not having to handle and store solid fuels, cost savings from decreased kiln downtime for cleaning and maintenance due to not burning solid fuels).

Attached to this letter, as part of Attachment 2, is e-mail correspondence from Spire indicating that they are working on a plan for providing additional natural gas supply to the LNA facility, and will inform LNA of the timing and their proposed solution to the gas supply issue no later than mid-July. LNA is not a large scale gas supply customer of Spire, and cannot significantly influence them to work to any schedule for implementation of a new gas pipeline. LNA is not a utility nor a company/entity that can interface with the Federal Energy Regulatory Commission (FERC) to implement installation of a new gas pipeline.

A new gas pipeline is a large-scale project that will be initiated and controlled by Spire. The project may also require modifications at nearby compressor stations. It is unknown at this time what costs would be passed on to LNA as a result of a new pipeline project, outside of expected gas cost supply increases to not just LNA but to all Spire customers in Montevallo and the greater Shelby County area to offset costs to Spire for the new pipeline project. However, none of those costs have been factored in to the analysis at this time, as they are completely unknown at this point. It is unlikely that any large-scale capital cost for the pipeline would be incurred or burdened onto LNA as this is an energy infrastructure project, for which costs are typically passed on to all pertinent consumers through supply cost increases. However, any direct costs to LNA for the new gas pipeline are unknown at this point.

At this time, LNA would propose moving forward with installation of the SO$_2$ CEMS as required and monitoring of the actual SO$_2$ emissions from the site for some time before any further action or requirements be imposed upon LNA associated with Regional Haze. Given uncertainties in the facility wide SO$_2$ emissions (as evidenced by ADEM's requirement to install SO$_2$ CEMS), and the potential influence of that data on all analyses (including requirement to conduct a four factor analysis, the omission of LNA from the refined PSAT modeling conducted by VISTAS, and still uncertain timing for when increased natural gas could be supplied to the facility, that course of action seems justifiable.

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If you have any questions or comments about the information presented in this letter, please feel free to contact Michael Will, the Alabama Regional Environmental Manager, at (205) 444-4905 or via email.

Sincerely,

Lhoist North America of Alabama, LLC

Craig Gordinier
Montevallo Plant Manager

Attachments

cc: Mr. Doug Carr (ADEM)
     Ms. Jennifer Youngpeter (ADEM)
     Mr. Chris Scholl (LNA)
     Mr. Michael Will (LNA)

ATTACHMENT 1

Emissions and Costing Calculations – Updated Information

Table 1. Economic Analysis - Alternative Fuel Scenarios - General Assumptions

Parameters	Value	Unit
Coal Sulfur Content[1]	1.47	%
Coke Sulfur Content[1]	5.25	%
Natural Gas Sulfur Content[2]	2.80E-04	lb S/MMBtu
Coal HHV[1]	26.85	MMBtu/ton
Coke HHV[1]	29.12	MMBtu/ton
Natural Gas HHV[2]	1,020	MMBtu/MMscf
Cost of Coal[3]	3.33	$/MMBtu
Cost of Coke[3]	2.21	$/MMBtu
Cost of Natural Gas[3]	4.16	$/MMBtu
Kilns 1 and 2 Percent of Input Sulfur in LKD/LKS[4]	5.93	%
Kilns 1 and 2 Percent of Input Sulfur in Lime[5]	2.60	%
Kilns 3 and 4 Percent of Input Sulfur in LKD/LKS[4]	13.31	%
Kilns 3 and 4 Percent of Input Sulfur in Lime[5]	7.33	%
SO$_2$ to S Molar Mass Ratio	2	
Low Sulfur Coal Sulfur Content[6]	0.83	%
Low Sulfur Coal HHV[6]	25.89	MMBtu/ton
Cost of Low Sulfur Coal[3]	3.82	$/MMBtu

1. From as received fuel sampling data.
2. Based on AP-42 Section 1.4.
3. Based on quoted fuel costs.
4. Based on Lhoist estimate for the percent of input sulfur that exits in the kiln in lime kiln dust (LKD)
or lime kiln suldge (LKS) from 2018 & 2019 data.
5. Based on Lhoist estimate for the percent of input sulfur that exits in the kiln in lime from customer product specifications.
6. From sampling data on Appalachian coal.

Table 2. Economic Analysis - Alternative Fuel Scenarios - Kiln Specific Assumptions[1]

Parameters	Value	Unit
Kiln 1 Fuel Efficiency[1]	10.6	MMBtu/ton production
Kiln 2 Fuel Efficiency[1]	12.0	MMBtu/ton production
Kiln 3 Fuel Efficiency[1]	7.2	MMBtu/ton production
Kiln 4 Fuel Efficiency[1]	7.6	MMBtu/ton production
Input Sulfur Removed by the Kiln 1 Venturi Scrubber[2]	75	%
Input Sulfur Removed by the Kiln 2 Venturi Scrubber[2]	75	%
Heat Input Required for Kiln 1[3]	956,700	MMBtu/yr
Heat Input Required for Kiln 2[3]	910,100	MMBtu/yr
Heat Input Required for Kiln 3[3]	1,440,000	MMBtu/yr
Heat Input Required for Kiln 4[3]	1,518,000	MMBtu/yr

1. Kiln specific parameters and assumptions based on Lhoist estimates for 2018 & 2019
2. Lhoist estimate based on percent of input sulfur removed by the scrubber.
3. Based on review of facility data from 2015-2019

Table 3. Economic Analysis - Alternative Fuel Scenarios - Baseline - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	36.4%	35.6%	38.4%	38.4%
Coke	54.6%	53.4%	57.6%	57.6%
Natural Gas	9.0%	11.0%	4.0%	4.0%

1. Fuel mix based on Lhoist estimates for 2019.

Table 4. Economic Analysis - Alternative Fuel Scenarios - Baseline

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	$ -	$ -	$ -	$ -	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ 1,160,882	$ 1,080,066	$ 1,843,337	$ 1,943,185	$ 6,027,470
Coke	$ 1,153,701	$ 1,073,384	$ 1,831,934	$ 1,931,164	$ 5,990,183
Natural Gas	$ 358,085	$ 416,341	$ 239,546	$ 252,522	$ 1,266,494
Total Annualized Cost[4]	$ 2,672,668	$ 2,569,791	$ 3,914,818	$ 4,126,870	$ 13,284,147

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 5. Economic Analysis - Alternative Fuel Scenarios - Baseline - SO_2 Emissions with Add-On Controls

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	62.8	58.4	481	507	1,108
Coke (tpy)[1]	310	288.6	2,373	2,502	5,474
Natural Gas (tpy)[2]	3.97E-03	4.62E-03	1.28E-02	1.35E-02	3.49E-02
Total	373	347	2,854	3,008	6,582

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

ADEM3 Scenario Table 1. Economic Analysis - Fuel Mix[1]

	Kiln 3	Kiln 4
Coal	30.0%	30.0%
Coke	43.0%	43.0%
Natural Gas	27.0%	27.0%
Low Sulfur Coal	0.0%	0.0%

1. Annualized fuel mix based on 67.5 MMBtu/hr of available natural gas supply (each) to Kilns 3 and 4.

ADEM3 Scenario Table 2. Economic Analysis - Natural Gas

	Kiln 3	Kiln 4	Total
Capital Costs			
New Burners[1]	$ 365,000	$ 365,000	$ 730,000
New Burner Management System[1]	$ 515,000	$ 515,000	$ 1,030,000
Natural Gas Plant Supply Lines[1]	$ 178,080	$ 178,080	$ 356,160
Kiln Downtime for Install[1]	$ 844,032	$ 825,023	$ 1,669,055
Total Capital Investment[2]	$ 1,902,112	$ 1,883,103	$ 3,785,215
Capital Recovery Factor[3]	0.09	0.09	0.09
Annualized Capital Costs[4]	$ 179,546	$ 177,752	$ 357,297
Annual Costs			
Coal	$ 1,440,107	$ 1,518,113	$ 2,958,220
Coke	$ 1,367,590	$ 1,441,667	$ 2,809,257
Natural Gas	$ 1,616,939	$ 1,704,523	$ 3,321,462
Low Sulfur Coal	$ -	$ -	$ -
Total Annualized Cost[5]	$ 4,604,182	$ 4,842,055	$ 9,446,237

1. Based on quotes and Lhoist estimates.
2. Total Capital Investment is equal to the sum of all capital costs.
3. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
4. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
5. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

ADEM3 Scenario Table 3. Economic Analysis - Natural Gas - SO2 Emissions

	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	375	396	771
Coke (tpy)[1]	1,772	1,868	3,639
Natural Gas (tpy)[2]	8.64E-02	9.11E-02	1.78E-01
Low Sulfur Coal (tpy)[1]	0.0	0.0	0.0
Total	2,147	2,264	4,411

1. Baseline SO2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%)]

ADEM3 Scenario Table 4. Economic Analysis - Natural Gas - Cost Effectiveness[1]

	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-707	-745	-1,452
Total Annualized Cost Difference	$ 689,364	$ 715,185	$ 1,404,549
Cost Effectiveness ($/ton reduced)	$ 976	$ 960	$ 968

1. Kilns 1 and 2 are unchanged from the baseline and are therefore excluded from the ADEM3 Scenario analysis.

ADEM4 Scenario Table 1. Economic Analysis - Natural Gas - Fuel Mix

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	0.0%	0.0%	0.0%	0.0%
Coke	0.0%	0.0%	0.0%	0.0%
Natural Gas	100.0%	100.0%	100.0%	100.0%
Low Sulfur Coal	0.0%	0.0%	0.0%	0.0%

ADEM4 Scenario Table 2. Economic Analysis - Natural Gas

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
New Burners[1]	$ 365,000	$ 365,000	$ 365,000	$ 365,000	$ 1,460,000
New Burner Management System[1]	$ 515,000	$ 515,000	$ 515,000	$ 515,000	$ 2,060,000
Natural Gas Plant Supply Lines[1]	$ 152,640	$ 152,640	$ 178,080	$ 178,080	$ 661,440
Kiln Downtime for Install[1]	$ 371,260	$ 313,509	$ 844,032	$ 825,023	$ 2,353,824
Total Capital Investment[2]	$ 1,403,900	$ 1,346,149	$ 1,902,112	$ 1,883,103	$ 6,535,264
Capital Recovery Factor[3]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[4]	$ 132,518	$ 127,067	$ 179,546	$ 177,752	$ 616,883
Annual Costs					
Coal	$ -	$ -	$ -	$ -	$ -
Coke	$ -	$ -	$ -	$ -	$ -
Natural Gas	$ 3,978,718	$ 3,784,918	$ 5,988,662	$ 6,313,048	$ 20,065,346
Low Sulfur Coal	$ -	$ -	$ -	$ -	$ -
Annual Cost Savings					
Electricity and Labor Reduction[5]	$ (117,053)	$ (117,053)	$ (117,053)	$ (117,053)	$ (468,213)
Maintenance Reduction[6]	$ (200,820)	$ (200,820)	$ (200,820)	$ (200,820)	$ (803,281)
Downtime Reduction[7]	$ (49,612)	$ (77,911)	$ (79,882)	$ (64,823)	$ (272,227)
Total Annualized Cost[8]	$ 3,743,750	$ 3,516,201	$ 5,770,453	$ 6,108,103	$ 19,138,507

1. Based on quotes and Lhoist estimates.
2. Total Capital Investment is equal to the sum of all capital costs.
3. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
4. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
5. Lhoist estimate for reduction in labor and electricity costs from removal of the solid fuel handling system. Cost savings split evenly per kiln.
6. Lhoist estimate for reduction in maintenance costs from removal of the solid fuel handling system. Cost savings split evenly per kiln.
7. Lhoist estimate for reduction in downtime caused by solid fuel usage.
5. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

ADEM4 Scenario Table 3. Economic Analysis - Natural Gas - SO2 Emissions

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	0.0	0.0	0.0	0.0	0
Coke (tpy)[1]	0.0	0.0	0.0	0.0	0
Natural Gas (tpy)[2]	4.41E-02	4.20E-02	3.20E-01	3.37E-01	7.44E-01
Low Sulfur Coal (tpy)[1]	0.0	0.0	0.0	0.0	0.0
Total	0.04	0.04	0.3	0.3	0.7

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%).- Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

ADEM4 Scenario Table 4. Economic Analysis - Natural Gas - Cost Effectiveness

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-373	-347	-2,854	-3,008	-6,582
Total Annualized Cost Difference	$ 1,071,082	$ 946,410	$ 1,855,635	$ 1,981,233	$ 5,854,360
Cost Effectiveness ($/ton reduced)	$ 2,872	$ 2,727	$ 650	$ 659	$ 889

ATTACHMENT 2

Documentation from Spire

spire (

March 12, 2021

Michael Will
Lhoist North America
7444 Hwy 25
Calera, Al 35040

Dear Michael,

Thank you for inquiring about increasing your natural gas usage in order to reduce the use of coal at your Lhoist Montevallo plant. Lhoist's current total connective load is 330 MMBtu per hour and is served on an interruptible basis. You have indicated that you would need approximately 1000 MMBtu per hour to operate the kilns on 100% natural gas. Unfortunately, Spire does not have the capacity to serve any additional load for the faciality beyond the 330 MMBtu/hr currently provided, but is working on a solution for future additional capacity.

Sincerely,

Craig Carter
LCI Business Development Representative

From:	Carter, Craig <Craig.Carter@spireenergy.com>
Sent:	Thursday, April 15, 2021 11:49 AM
To:	WILL Michael
Subject:	Gas supply meeting
Categories:	VIP Correspondance

Caution! External email. Do not open any links or attachments unless you trust the sender and know the content is safe. If unsure, please report the message with the **PhishAlarm** button in Outlook.

Michael,

Last week 4/8 our Spire team had a conference call with Lhoist to discuss timing of solutions for the deficiencies in needed natural gas supply for the Lhoist Montevallo plant. Joe Hampton (President Spire Alabama, Gulf and Mississippi) participated in the call and assured Lhoist that Spire would inform them of the timing and solution to the gas supply issue no later than mid-July. We will continue to keep Lhoist informed as we move forward with this process.

Craig Carter
LCI Business Development Representative
(205)572-2568 Mobile
SpireEnergy.com

LANCE R. LeFLEUR
DIRECTOR

ADEM

Alabama Department of Environmental Management
adem.alabama.gov

KAY IVEY
GOVERNOR

1400 Coliseum Blvd. 36110-2400 ■ Post Office Box 301463
Montgomery, Alabama 36130-1463
(334) 271-7700 ■ FAX (334) 271-7950

September 23, 2024

Mr. Grant McCallum
Plant Manager
Lhoist North America of Alabama, LLC
Montevallo Plant
7444 Highway 25 South
Calera, AL 35040

RE: **Regional Haze Rule – Four-Factor Analysis Follow-Up**
   Lhoist – Montevallo Plant
   Facility No. 411-0008

Dear Mr. McCallum:

On February 5, 2021, Lhoist North America of Alabama, Inc. (Lhoist) provided information to the Department known as a "four-factor analysis". This information enabled the Department to determine whether SO_2 reductions were feasible at Lhoist's Montevallo Plant for the purpose of improving visibility at the Sipsey Wilderness Area. The Department requested additional information on March 2, 2021, and Lhoist provided a revised "four-factor analysis" on March 29, 2021.

In its revised submission, Lhoist included analyses of alternative fuel scenarios using increasing increments of natural gas for each kiln. The response also included a letter from Spire Inc. stating the facility currently has a connective load capacity of 330 MMBtu of natural gas per hour (MMBtu/hr) and is working on a potential solution to provide additional capacity (i.e., to 1,000 MMBtu/hr to operate all kilns on 100% natural gas) in the future.

The Department requests a response to the following no later than October 29, 2024:

1) Has Lhoist been in contact with Spire Inc. regarding a provision of additional natural gas capacity to the Montevallo Plant? If there have been any developments, please provide details.

2) What is the current connective load capacity at the Montevallo Plant?

If you have any questions concerning this matter, please contact Jackson Rogers at (334) 271-7784 in Montgomery.

Sincerely,

Ronald W. Gore, Chief
Air Division

RWG/RJR

Birmingham Branch
110 Vulcan Road
Birmingham, AL 35209-4702
(205) 942-6168
(205) 941-1603 (FAX)

Decatur Branch
2715 Sandlin Road, S.W.
Decatur, AL 35603-1333
(256) 353-1713
(256) 340-9359 (FAX)

Mobile Branch
2204 Perimeter Road
Mobile, AL 36615-1131
(251) 450-3400
(251) 479-2593 (FAX)

Mobile-Coastal
3664 Dauphin Street, Suite B
Mobile, AL 36608
(251) 304-1176
(251) 304-1189 (FAX)

Lhoist North America
Lhoist Group

November 15, 2024

Mr. Ron Gore
Alabama Department of Environmental Management
Air Division
1400 Coliseum Boulevard
Montgomery, AL 36110-2059

Re: Regional Haze Rule – Four-Factor Analysis Followup

Mr. Gore:

Lhoist North America of Alabama, LLC (LNA) owns and operates the Montevallo Plant, a lime manufacturing facility in Shelby County, Alabama, pursuant to Major Source Operating Permit, 411-0008. On October 21st, 2024, we received your letter concerning the regional haze rule. To respond to the questions that were posed in that letter,

1) *Has Lhoist been in contact with Spire, Inc. regarding a provision of additional natural gas capacity to the Montevallo Plant? If there have been any developments, please provide details.*

Lhoist has had ongoing discussions with Spire to increase capacity at the Montevallo Plant. There have been improvements in guaranteed capacity for the facility but no real significant improvements overall to the facility's supply. Please note that the facility is currently supplied through two separate connections, one for Kilns 1-4 and the other for Kiln 5.

2) *What is the current connective load capacity at the Montevallo Plant?*

Please see the attached letter detailing the connective load for the Montevallo Plant. Spire has requested that the letter be treated as CBI since it contains information from our gas contract which is confidential.

If the Department has any further questions about the, please contact me via email.

Sincerely,

Lhoist North America of Alabama, LLC

Grant McCallum, Montevallo Plant Manager

CC: Michael Will – Regional Environmnetal Manager
Jodie Edwards – Environmental Engineer, Alabama Operations

Attachment: Letter from Spire (CBI)
GM/mw

Spire Inc.
273 Cahaba Valley Parkway N
Pelham, Al. 35124

November 14, 2024

Michael Will
Lhoist North America
7444 Highway 25
Calera, Al. City, e Zip

Dear Michael,

Thank you for the inquiry about natural gas capacity at the Lhoist Montevallo Plant. Lhoist's current total contracted connective load is 10,000 MMBtu per day. This total load consists of 5000 MMBtu per day (208 MMBtu/hr) which is served on a firm basis and up to 5000 MMBTU/day (208 MMBtu/hr) served on an interruptible basis. Interruptible basis means that this capacity is not guaranteed, and Spire can stop or curtail gas usage. Spire has agreed to provide 494,000 cubic feet per hour of which a maximum of 240,000 cubic feet per hour would be available for Kilns 1-4. In the past, Lhoist has indicated that 1000 MMBtu per hour would need to be available to operate the kilns at or near 100% natural gas. Spire has made progress but does not have the capacity to provide any additional guaranteed load capacity and is still working to implement solutions to supply additional capacity in the future.

Sincerely,

Craig Carter
LCI Business Development Representative

Appendix G-1g

Lhoist Montevallo Four Factor Analysis Addendum #3 - June 23, 2021

June 23, 2021

Mr. Skyler Sanderson
Environmental Engineering Specialist, Senior
Air Division, Energy Branch
Alabama Department of Environmental Management
1400 Coliseum Boulevard
Montgomery, AL 36110-2400
(334) 270 - 5647
skyler.sanderson@adem.alabama.gov

RE: *Lhoist North America of Alabama, LLC - Montevallo Plant*
Regional Haze Rule – Four-Factor Analysis Additional Information Request During 6/16/21
Conference Call

Dear Mr. Sanderson:

Lhoist North America of Alabama, LLC (LNA) owns and operates the Montevallo Plant, comprising of a lime manufacturing facility located in Calera, Shelby County, Alabama operating under Title V Major Source Operating Permit No. 411-0008 issued by the Alabama Department of Environmental Management (ADEM). LNA is submitting this letter in response to the ADEM additional information requested during our conference call held with ADEM on June 16, 2021.

Specifically, the key items of concern addressed in this letter are as follows:

- Additional requested information regarding an additional fuel scenario involving higher usage rates of natural gas on Kilns 3 and 4, at 22% natural gas per kiln. Data provided includes an economic evaluation for natural gas usage (at 22%), which the facility can achieve without infrastructure changes (e.g., physical piping component upgrades, burner upgrades, etc.) and information on why 22% is the optimal natural gas usage for Kilns 3 and 4 without any physical upgrades to the system and with current natural gas supply and availability.
- An economic analysis for use of the currently available natural gas supply on Kilns 3 and 4 (27%), including costs for physical upgrades to facility equipment, and an incremental cost evaluation in going from 22% natural gas usage to 27% natural gas usage.
- Proposed methodologies for long term monitoring of facility fuel use, heating value, etc. for a long term (annual/12-month rolling) demonstration that Kilns 3 and 4 will be using 22% natural gas moving forward.

Supporting documentation for this submittal is included in the attachment to this letter.

- Attachment 1 - Updated detailed economic analysis documentation, including the requested analyses as outlined above.

22% NATURAL GAS USAGE ANALYSIS

An economic analysis on increased natural gas usage on Kilns 3 and 4 (at 22% natural gas), while keeping Kilns 1 and 2 at their current long-term capacity, was conducted. A summary of the results of this analysis is shown below in Table 1, with additional details for the analysis provided in Attachment 1 (labeled 22% Natural Gas Scenario).

Table 1: Kiln 3 and Kiln 4 22% Natural Gas Analyses

	Kiln 3	Kiln 4	Total
SO$_2$ Emissions Difference (tpy)	-587	-618	-1,205
Total Annualized Cost Difference	$ 418,004	$ 440,646	$ 858,651
Cost Effectiveness ($/ton reduced)	$ 712	$ 712	$ 712

1. Kilns 1 and 2 are unchanged from the baseline and are therefore excluded from the analysis.

LNA has determined that 22% is the appropriate and available usage level for natural gas on Kilns 3 and 4, due to the following:

1. Available natural gas supply to the facility, leaves up to 67.5 MMBtu/hr per kiln for Kilns 3 and 4 available.

   [330 MMBtu/hr (Supply) – 100 MMBtu/hr (Kiln 5 capacity) – 20 MMBtu/hr (Limestone Dryer) – 75 MMBtu/hr (current Kiln 1 and 2 usage)] / 2 kilns = 67.5 MMBtu/hr per Kiln

2. However, the kilns are currently limited by the available natural gas supply infrastructure at the site, as well as the existing burner management system and installed natural gas burner (design rating of 60 MMBtu/hr).

3. Testing and evaluation during the several weeks prior to the call with ADEM on June 16, 2021, saw that Kiln 3 and Kiln 4 could operate nominally at 22% natural gas, without any negative influences to other facility natural gas usage operations.

27% NATURAL GAS USAGE ANALYSES AND INCREMENTAL COST EFFECTIVENESS FROM 22% NATURAL GAS USAGE

An additional natural gas usage scenario at 27% natural gas was evaluated for Kiln 3 and Kiln 4 as requested, including an incremental cost analysis in moving from 22% natural gas usage (with no necessary facility upgrades) on Kiln 3 and Kiln 4, to use of up to 27% natural gas on Kiln 3 and Kiln 4 with necessary facility upgrades. A summary of the results of this new analysis is shown below in Table 2, with additional details for the analysis provided in Attachment 1 (labeled 27% Natural Gas Scenario).

Table 2: Kiln 3 and Kiln 4 Incremental Cost Effectiveness Moving from 22% Natural Gas Usage to 27% Natural Gas Usage

	Kiln 3	Kiln 4	Total
SO$_2$ Incremental Emissions Difference (tpy)	-120	-126	-246
Incremental Annualized Cost Difference	$ 271,359	$ 274,538	$ 545,898
Incremental Cost Effectiveness ($/ton reduced)	$ 2,263	$ 2,171	$ 2,216

As can be seen from the results presented in Table 2, the incremental cost effectiveness in moving from 22% natural gas usage to 27% natural gas usage would be greater than $2,000/ton.

MONITORING METHODS FOR DEMONSTRATION OF NATURAL GAS USAGE ON KILN 3 AND KILN 4

LNA will continue to conduct normal facility fuel usage measurements and heating value measurements as follows, in order to evaluate and demonstrate on a 12-month rolling basis that at least 22% natural gas usage on Kiln 3 and Kiln 4 is maintained.

1. Conduct and maintain monthly fuel usage records for coal and coke in Kilns 3 and 4, in tons of solid fuel usage for each kiln.
2. Conduct and maintain records of monthly fuel heating value analyses for coal and coke, as received, for the Montevallo Facility, in Btu/lb, to evaluate the total monthly heat input contributed coal and coke for each kiln.
3. Record and maintain, on a monthly basis, monthly natural gas usage on Kiln 3 and Kiln 4 as recorded by the Kiln 3 and Kiln 4 burner management system. A standard heating value for natural gas (1,020 Btu/scf) will be presumed. Heating value can be reviewed by LNA annually to ensure that the presumed value is accurate. The heat input contribution for Kiln 3 and Kiln 4 from natural gas, on a monthly basis, can then be estimated.
4. Using the above data, compile the total monthly heat input to Kiln 3 and Kiln 4 and demonstrate that on a 12-month rolling basis Kiln 3 and 4 natural gas usage is at least 22% of the fuel usage for those sources.

~~~~~~~~~~~~~~~~~~~~~~~~

If you have any questions or comments about the information presented in this letter, please feel free to contact Michael Will, the Alabama Regional Environmental Manager, at (205) 444-4905 or via email.

Sincerely,

Lhoist North America of Alabama, LLC

Craig Gordinier
Montevallo Plant Manager

Attachments

cc: Mr. Doug Carr (ADEM)
     Ms. Jennifer Youngpeter (ADEM)
     Mr. Chris Scholl (LNA)
     Mr. Michael Will (LNA)

ATTACHMENT 1

Emissions and Costing Calculations – Updated Information

Table 1. Economic Analysis - Alternative Fuel Scenarios - General Assumptions

Parameters	Value	Unit
Coal Sulfur Content[1]	1.47	%
Coke Sulfur Content[1]	5.25	%
Natural Gas Sulfur Content[2]	2.80E-04	lb S/MMBtu
Coal HHV[1]	26.85	MMBtu/ton
Coke HHV[1]	29.12	MMBtu/ton
Natural Gas HHV[2]	1,020	MMBtu/MMscf
Cost of Coal[3]	3.33	$/MMBtu
Cost of Coke[3]	2.21	$/MMBtu
Cost of Natural Gas[3]	4.16	$/MMBtu
Kilns 1 and 2 Percent of Input Sulfur in LKD/LKS[4]	5.93	%
Kilns 1 and 2 Percent of Input Sulfur in Lime[5]	2.60	%
Kilns 3 and 4 Percent of Input Sulfur in LKD/LKS[4]	13.31	%
Kilns 3 and 4 Percent of Input Sulfur in Lime[5]	7.33	%
SO_2 to S Molar Mass Ratio	2	
Low Sulfur Coal Sulfur Content[6]	0.83	%
Low Sulfur Coal HHV[6]	25.89	MMBtu/ton
Cost of Low Sulfur Coal[3]	3.82	$/MMBtu

1. From as received fuel sampling data.
2. Based on AP-42 Section 1.4.
3. Based on quoted fuel costs.
4. Based on Lhoist estimate for the percent of input sulfur that exits in the kiln in lime kiln dust (LKD) or lime kiln suldge (LKS) from 2018 & 2019 data.
5. Based on Lhoist estimate for the percent of input sulfur that exits in the kiln in lime from customer product specifications.
6. From sampling data on Appalachian coal.

Table 2. Economic Analysis - Alternative Fuel Scenarios - Kiln Specific Assumptions[1]

Parameters	Value	Unit
Kiln 1 Fuel Efficiency[1]	10.6	MMBtu/ton production
Kiln 2 Fuel Efficiency[1]	12.0	MMBtu/ton production
Kiln 3 Fuel Efficiency[1]	7.2	MMBtu/ton production
Kiln 4 Fuel Efficiency[1]	7.6	MMBtu/ton production
Input Sulfur Removed by the Kiln 1 Venturi Scrubber[2]	75	%
Input Sulfur Removed by the Kiln 2 Venturi Scrubber[2]	75	%
Heat Input Required for Kiln 1[3]	956,700	MMBtu/yr
Heat Input Required for Kiln 2[3]	910,100	MMBtu/yr
Heat Input Required for Kiln 3[3]	1,440,000	MMBtu/yr
Heat Input Required for Kiln 4[3]	1,518,000	MMBtu/yr

1. Kiln specific parameters and assumptions based on Lhoist estimates for 2018 & 2019
2. Lhoist estimate based on percent of input sulfur removed by the scrubber.
3. Based on review of facility data from 2015-2019

Table 3. Economic Analysis - Alternative Fuel Scenarios - Baseline - Fuel Mix[1]

	Kiln 1	Kiln 2	Kiln 3	Kiln 4
Coal	36.4%	35.6%	38.4%	38.4%
Coke	54.6%	53.4%	57.6%	57.6%
Natural Gas	9.0%	11.0%	4.0%	4.0%

1. Fuel mix based on Lhoist estimates for 2019.

Table 4. Economic Analysis - Alternative Fuel Scenarios - Baseline

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Capital Costs					
N/A	$ -	$ -	$ -	$ -	$ -
Total Capital Investment[1]	$ -	$ -	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -	$ -	$ -
Annual Costs					
Coal	$ 1,160,882	$ 1,080,066	$ 1,843,337	$ 1,943,185	$ 6,027,470
Coke	$ 1,153,701	$ 1,073,384	$ 1,831,934	$ 1,931,164	$ 5,990,183
Natural Gas	$ 358,085	$ 416,341	$ 239,546	$ 252,522	$ 1,266,494
Total Annualized Cost[4]	$ 2,672,668	$ 2,569,791	$ 3,914,818	$ 4,126,870	$ 13,284,147

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

Table 5. Economic Analysis - Alternative Fuel Scenarios - Baseline - SO_2 Emissions with Add-On Controls

	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	62.8	58.4	481	507	1,108
Coke (tpy)[1]	310	288.6	2,373	2,502	5,474
Natural Gas (tpy)[2]	3.97E-03	4.62E-03	1.28E-02	1.35E-02	3.49E-02
Total	373	347	2,854	3,008	6,582

1. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%) - Input Sulfur Removed by Scrubber {if applicable} (%)]

22% Natural Gas Scenario Table 1. Economic Analysis - Fuel Mix[1]

	Kiln 3	Kiln 4
Coal	33.0%	33.0%
Coke	45.0%	45.0%
Natural Gas	22.0%	22.0%
Low Sulfur Coal	0.0%	0.0%

1. Annualized fuel mix based on available natural gas supply (each) to Kilns 3 and 4 with no fuel system upgrades.

22% Natural Gas Scenario Table 2. Economic Analysis - Natural Gas

	Kiln 3	Kiln 4	Total
Capital Costs			
N/A	-	-	$ -
Total Capital Investment[1]	$ -	$ -	$ -
Capital Recovery Factor[2]	0.09	0.09	0.09
Annualized Capital Costs[3]	$ -	$ -	$ -
Annual Costs			
Coal	$ 1,584,118	$ 1,669,924	$ 3,254,042
Coke	$ 1,431,198	$ 1,508,722	$ 2,939,920
Natural Gas	$ 1,317,506	$ 1,388,871	$ 2,706,376
Low Sulfur Coal	$ -	$ -	$ -
Total Annualized Cost[4]	$ 4,332,822	$ 4,567,517	$ 8,900,339

1. Total Capital Investment is equal to the sum of all capital costs.
2. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
3. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
4. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

22% Natural Gas Scenario Table 3. Economic Analysis - Natural Gas - SO_2 Emissions

	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	413	435	848
Coke (tpy)[1]	1,854	1,955	3,809
Natural Gas (tpy)[2]	7.04E-02	7.42E-02	1.45E-01
Low Sulfur Coal (tpy)[1]	0.0	0.0	0.0
Total	2,267	2,390	4,657

1. Baseline SO2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio * [100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%)]

22% Natural Gas Scenario Table 4. Economic Analysis - Natural Gas - Cost Effectiveness[1]

	Kiln 3	Kiln 4	Total
SO_2 Emissions Difference (tpy)	-587	-618	-1,205
Total Annualized Cost Difference	$ 418,004	$ 440,646	$ 858,651
Cost Effectiveness ($/ton reduced)	$ 712	$ 712	$ 712

1. Kilns 1 and 2 are unchanged from the baseline and are therefore excluded from the analysis.

27% Natural Gas Scenario Table 1. Economic Analysis - Fuel Mix[1]

	Kiln 3	Kiln 4
Coal	30.0%	30.0%
Coke	43.0%	43.0%
Natural Gas	27.0%	27.0%
Low Sulfur Coal	0.0%	0.0%

1. Annualized fuel mix based on 67.5 MMBtu/hr of available natural gas supply (each) to Kilns 3 and 4.

27% Natural Gas Scenario Table 2. Economic Analysis - Natural Gas

	Kiln 3	Kiln 4	Total
Capital Costs			
New Burners[1]	$ 365,000	$ 365,000	$ 730,000
New Burner Management System[1]	$ 515,000	$ 515,000	$ 1,030,000
Natural Gas Plant Supply Lines[1]	$ 178,080	$ 178,080	$ 356,160
Kiln Downtime for Install[1]	$ 844,032	$ 825,023	$ 1,669,055
Total Capital Investment[2]	$ 1,902,112	$ 1,883,103	$ 3,785,215
Capital Recovery Factor[3]	0.09	0.09	0.09
Annualized Capital Costs[4]	$ 179,546	$ 177,752	$ 357,297
Annual Costs			
Coal	$ 1,440,107	$ 1,518,113	$ 2,958,220
Coke	$ 1,367,590	$ 1,441,667	$ 2,809,257
Natural Gas	$ 1,616,939	$ 1,704,523	$ 3,321,462
Low Sulfur Coal	$ -	$ -	$ -
Total Annualized Cost[5]	$ 4,604,182	$ 4,842,055	$ 9,446,237

1. Based on quotes and Lhoist estimates.
2. Total Capital Investment is equal to the sum of all capital costs.
3. Capital Recovery Factor calculated using formula from EPA OAQPS Control Cost Manual. Assumes 7% interest and 20 year lifespan.
4. Annualized Capital Costs = Total Capital Investment * Capital Recovery Factor
5. Total Annualized Cost = Annualized Capital Costs + sum of Annual Costs

27% Natural Gas Scenario Table 3. Economic Analysis - Natural Gas - SO_2 Emissions

	Kiln 3	Kiln 4	Total
Coal (tpy)[1]	375	396	771
Coke (tpy)[1]	1,772	1,868	3,639
Natural Gas (tpy)[2]	8.64E-02	9.11E-02	1.78E-01
Low Sulfur Coal (tpy)[1]	0.0	0.0	0.0
Total	2,147	2,264	4,411

1. Baseline SO2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) / HHV (MMBtu/ton) * Sulfur Content (%) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%)]
2. Baseline SO_2 Emissions (tpy) = Heat Input Required (MMBtu/yr) * Fuel Mix (%) * Sulfur Content (lb S/MMBtu) / 2,000 (lb/ton) * Molar Mass Ratio *
[100% - Input Sulfur in LKD/LKS (%) - Input Sulfur in Lime (%)]

27% Natural Gas Scenario Table 4. Economic Analysis - Natural Gas - Incremental Cost Effectiveness From 22% Natural Gas Scenario[1]

	Kiln 3	Kiln 4	Total
SO_2 Incremental Emissions Difference (tpy)	-120	-126	-246
Total Annualized Cost Difference	$ 689,364	$ 715,185	$ 1,404,549
Incremental Annualized Cost Difference	$ 271,359	$ 274,538	$ 545,898
Incremental Cost Effectiveness ($/ton reduced)	$ 2,263	$ 2,171	$ 2,216

1. Kilns 1 and 2 are unchanged from the baseline and are therefore excluded from the analysis.

Appendix G-1h

Engineering Analysis to Incorporate New Requirements as a Result of Four Factor Analysis

Engineering Analysis
Lhoist North America of Alabama, LLC – Montevallo Plant
Calera, Shelby County, Alabama
Facility No. 411-0008

DESCRIPTION

On October 29, 2020, the Department issued a letter to Lhoist North America of Alabama, LLC (Lhoist) requiring Lhoist to complete a four-factor analysis for sulfur dioxide (SO_2) emissions as part of the 2017 Regional Haze Rule, 40 CFR Parts 51 and 52. The Department requested additional information on March 2, 2021, April 14, 2021, and June 16, 2021, in order to complete its assessment of the analysis. The analysis looked at different control technology options to reduce SO_2 emissions from sources at the Montevallo Plant.

On April 27, 2021, the Department issued a letter to Lhoist requiring them to install and operate a SO_2 continuous emissions monitoring system (CEMS) with a flow meter on Kiln Nos. 3 and 4 at Montevallo Plant. Lhoist responded on June 22, 2021, with the proposed CEMS location on the combined kiln stack and a timeline for installation and certification. Lhoist stated that a CEMS and flow meter should be installed and certified by April 22, 2022. The Department responded on July 2, 2021, approving the proposed timeline and location of the CEMS.

EMISSIONS

Sulfur dioxide (SO_2) emissions from Kiln Nos. 3 and 4 combined shall not exceed 4,657 tons per year (TPY) in any 12-month rolling period. Natural gas shall make up at least 22% of total fuel usage, on a MMBtu basis, in Kiln Nos. 3 and 4 in any 12-month rolling period.

COMPLIANCE AND PERFORMANCE TESTING

The kilns are currently required to perform annual particulate matter emissions testing. If testing is required, the following methods described in 40 CFR Part 60, Appendix A, shall be used:

Method	Pollutant
5	Particulate matter (PM)
6, 6A	Sulfur dioxide (SO_2)
7, 7E	Nitrogen oxides (NO_x)
9	Opacity
10	Carbon monoxide (CO)
25A	Volatile organic compounds (VOC)
321	Hydrogen chloride (HCl)

PERIODIC MONITORING

By May 1, 2022, the permittee shall install, operate, maintain, and calibrate a continuous emissions monitoring system (CEMS) with a flow meter at a location approved by the Director in order to

determine compliance with the applicable sulfur dioxide (SO_2) emissions standard. The CEMS and flow meter shall comply with the applicable specifications and procedures outlined in 40 CFR Part 75, Appendices A, B and C.

COMPLIANCE ASSURANCE MONITORING (CAM)

Per §64.2(a), CAM applies to a pollutant-specific emissions unit at a major source required to obtain a Part 70 or 71 permit if it meets the following criteria: the unit is subject to an emissions limit, uses a control device to achieve compliance with that limit, and has potential pre-control device emissions of that pollutant that are equal to or greater than the major source threshold of 100 TPY for a criteria pollutant, 10 TPY for any single HAP, or 25 TPY for any combination of HAPs.

The kilns are currently subject to the requirements of CAM, which are considered satisfied by meeting the requirements of 40 CFR Part 63 Subpart AAAAA. Since the use of natural gas would not meet the definition of a control device in 40 CFR §64.1, CAM would not apply for this emissions limit.

RECORDKEEPING AND REPORTING

All original data charts, performance evaluations, calibration checks, adjustments, and maintenance records for the CEMS and flow meter shall be kept in a permanent form suitable for inspection. These records shall be maintained for a period of at least five (5) years from the date of generation and shall be made available to the permitting authority upon request.

The permittee shall record the monthly fuel usage of each kiln in terms of MMBtu of each fuel type. The percentage of natural gas usage based on MMBtu during the previous 12-month period shall be calculated for each month within ten days of the end of the month.

Quarterly excess emissions reports (EER) shall be submitted to the Department for each calendar quarter within the month following the quarter. The reports shall include the following information:

(a) The rolling 12-month natural gas usage (percentage of total fuel based on MMBtu) for Kiln Nos. 3 and 4 for each calendar month in the quarter;

(b) The magnitude of SO_2 emissions for Kiln Nos. 3 and 4 in excess of the applicable emissions standard, as determined by the CEMS;

(c) The date, time, and duration of each period of excess emissions;

(d) The nature and cause of each period of excess emissions, if known;

(e) Description of any corrective action or preventive measures implemented in response to excess emissions;

(f) Data recorded during periods associated with monitor breakdowns, repairs, calibrations, and zero and span adjustments shall not be included in data averages;

(g) The date and time of each period in which the CEMS was inoperative, excluding periods of zero and span checks, and the nature of any system repairs or adjustments performed;

(h) During periods in which no excess emissions have occurred, the CEMS has not been inoperative, and/or repairs and adjustments were not necessary, such information shall be stated in the report;

(i) The total source operating time (all times and periods in the appropriate averaging units, such as hours, days, minutes, etc.)

(j) The total time the CEMS was available to record source performance. Information identifying each period during which the monitoring system was inoperative, excluding zero and span checks, and the nature of any system repairs or adjustments shall also be included;

(k) Monitor availability expressed as percent (%) of source operating time, calculated as follows:

$$\frac{\text{Total monitor availability time}}{\text{Total source operating time}} * 100\%$$

(l) Overall performance, expressed as percent (%), calculated as follows:

$$\frac{[(\text{Total monitor availability time}) - (\text{Total time of excess emissions})]}{(\text{Total monitor availability time})} * 100\%$$

(m) Statement of certification of truth, accuracy, and completeness; and

(n) Signature of the responsible official.

RECOMMENDATION

Based on the above analysis, I recommend Lhoist be issued the following air permit for Kiln Nos. 3 and 4 with the applicable SO_2 standards. If Lhoist adheres to the permit conditions, it should be in compliance with all State and Federal air pollution regulations.

Permit Number	Description
411-0008-X053	Kiln No. 3 controlled by Baghouse No. BH-0303 & Kiln No. 4 controlled by Baghouse No. BH-0403 with Common Stack (CA-03)

Skyler Sanderson
_____
Skyler Sanderson
Industrial Minerals Section
Energy Branch
Air Division

September 21, 2021
Date

Appendix G-1i

Air Permit Issued to Incorporate New Requirements as a Result of Four Factor Analysis

LANCE R. LeFLEUR
DIRECTOR

ADEM

Alabama Department of Environmental Management
adem.alabama.gov

1400 Coliseum Blvd. 36110-2400 ■ Post Office Box 301463
Montgomery, Alabama 36130-1463
(334) 271-7700 ■ FAX (334) 271-7950

KAY IVEY
GOVERNOR

September 21, 2021

Craig Gordinier
Plant Manager
Lhoist North America of Alabama, LLC – Montevallo Plant
7444 Highway 25 South
Calera, AL 35115

RE: Facility No. 411-0008
Permit No. X053

Dear Mr. Gordinier:

The enclosed Air Permit is issued pursuant to the Department's air pollution control rules and regulations. Please note the conditions which must be observed in order to retain this permit.

If you have any questions or require clarification of permit conditions, please contact Skyler Sanderson at (334) 270-5647 in Montgomery.

Sincerely,

Ronald W. Gore, Chief
Air Division

RWG/MSS

Enclosures

Birmingham Branch
110 Vulcan Road
Birmingham, AL 35209-4702
(205) 942-6168
(205) 941-1603 (FAX)

Decatur Branch
2715 Sandlin Road, S.W.
Decatur, AL 35603-1333
(256) 353-1713
(256) 340-9359 (FAX)

Mobile Branch
2204 Perimeter Road
Mobile, AL 36615-1131
(251) 450-3400
(251) 479-2593 (FAX)

Mobile-Coastal
3664 Dauphin Street, Suite B
Mobile, AL 36608
(251) 304-1176
(251) 304-1189 (FAX)

ADEM

Alabama Department of Environmental Management

AIR PERMIT

PERMITTEE:	LHOIST NORTH AMERICA OF ALABAMA, LLC
FACILITY NAME:	MONTEVALLO PLANT
LOCATION:	CALERA, AL

PERMIT NUMBER	DESCRIPTION OF EQUIPMENT, ARTICLE, OR DEVICE
411-0008-X053	Kiln No. 3 controlled by Baghouse No. BH-0303 & Kiln No. 4 controlled by Baghouse No. BH-0403 with Common Stack (CA-03)

In accordance with and subject to the provisions of the Alabama Air Pollution Control Act of 1971, Ala. Code §§22-28-1 to 22-28-23, as amended, the Alabama Environmental Management Act, Ala. Code §§22-22A-1 to 22-22A-17, as amended, and rules and regulations adopted there under, and subject further to the conditions set forth in this permit, the Permittee is hereby authorized to construct, install and use the equipment, device or other article described above.

ISSUANCE DATE: September 21, 2021

_____
Alabama Department of Environmental Management

Page 1 of 10

General Permit Provisos

1. This permit is issued on the basis of Rules and Regulations existing on the date of issuance. In the event additional Rules and Regulations are adopted, it shall be the permit holder's responsibility to comply with such rules.

2. This permit is not transferable. Upon sale or legal transfer, the new owner or operator must apply for a permit within 30 days.

3. A new permit application must be made for new sources, replacements, alterations or design changes which may result in the issuance of, or an increase in the issuance of, air contaminants, or the use of which may eliminate or reduce or control the issuance of air contaminants.

4. Each point of emission, which requires testing, will be provided with sampling ports, ladders, platforms, and other safety equipment to facilitate testing performed in accordance with procedures established by Part 60 of Title 40 of the Code of Federal Regulations, as the same may be amended or revised.

5. All air pollution control equipment shall be operated at all times while this process is operational. In the event of scheduled maintenance, unscheduled maintenance, or a breakdown of the pollution control equipment, the process shall be shutdown as expeditiously as possible (unless this act and subsequent re-start would clearly cause greater emissions than continuing operations of the process for a short period). The Department shall be notified of all such events **that exceed 1 hour** within 24 hours. The notification shall include all pertinent facts, including the duration of the process operating without the control device and the level of excess emissions which have occurred. Records of all such events, regardless of reporting requirements, shall be made and maintained for a period of five years. These records shall be available for inspection.

6. In the event there is a breakdown of air pollution control or process equipment in such a manner as to cause increased emission of air contaminants for a period greater than **1 hour**, the person responsible for such equipment shall notify the Air Division within 24 hours and provide a statement giving all pertinent facts, including the duration of the breakdown. The Air Division shall be notified when the breakdown has been corrected.

7. All deviations from requirements within this permit shall be reported to the Department within 48 hours of the deviation or by the next work day while providing a statement with regards to the date, time, duration, cause, and corrective actions taken to bring the sources back into compliance.

8. This process, including all air pollution control devices and capture systems for which this permit is issued, shall be maintained and operated at all times in a manner so as to minimize the emissions of air contaminants. Procedures for ensuring that the above equipment is properly operated and maintained so as to minimize the emission of air contaminants shall be established.

9. This permit expires and the application is cancelled if construction has not begun within 24 months of the date of issuance of the permit.

10. On completion of construction of the device(s) for which this permit is issued, written notification of the fact is to be submitted to the Chief of the Air Division. The notification shall indicate whether the device(s) was constructed as proposed in the application. The device(s) shall not be operated until authorization to operate is granted by the Chief of the Air Division. Failure to notify the Chief of the Air Division of completion of construction and/or operation without authorization could result in revocation of this permit.

11. Submittal of other reports regarding monitoring records, fuel analyses, operating rates, and equipment malfunctions may be required as authorized in the Department's air pollution control rules and regulations. The Department may require stack emission testing at any time.

12. Additions and revisions to the conditions of this Permit will be made, if necessary, to ensure that the Department's air pollution control rules and regulations are not violated.

13. Nothing in this permit or conditions thereto shall negate any authority granted to the Air Division pursuant to the Alabama Environmental Management Act or regulations issued thereunder.

14. This permit is issued with the condition that, should obnoxious odors arising from the plant operations be verified by Air Division inspectors, measures to abate the odorous emissions shall be taken upon a determination by the Alabama Department of Environmental Management that these measures are technically and economically feasible.

15. The Air Division must be notified in writing at least 10 working days in advance of all emission tests to be conducted and submitted as proof of compliance with the Department's air pollution control rules and regulations.

To avoid problems concerning testing methods and procedures, the following shall be included with the notification letter:

a. The date the test crew is expected to arrive, the date and time anticipated of the start of the first run, how many and which sources are to be tested, and the names of the persons and/or testing company that will conduct the tests.

b. A complete description of each sampling train to be used, including type of media used in determining gas stream components, type of probe lining, type of filter media, and probe cleaning method and solvent to be used (if test procedure requires probe cleaning).

c. A description of the process(es) to be tested, including the feed rate, any operating parameter used to control or influence the operations, and the rated capacity.

d. A sketch or sketches showing sampling point locations and their relative positions to the nearest upstream and downstream gas flow disturbances.

A pretest meeting may be held at the request of the source owner or the Department. The necessity for such a meeting and the required attendees will be determined on a case-by-case basis.

All test reports must be submitted to the Air Division within 30 days of the actual completion of the test, unless an extension of time is specifically approved by the Air Division.

16. Records will be maintained of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the process equipment and any malfunction of the air pollution control equipment. These records will be kept in a permanent form suitable for inspection and will be retained for at least two years following the date of each occurrence.

17. Precautions shall be taken to prevent fugitive dust emanating from plant roads, grounds, stockpiles, screens, dryers, hoppers, ductwork, etc.

    Plant or haul roads and grounds will be maintained in the following manner so that dust will not become airborne. A minimum of one, or a combination, of the following methods shall be utilized to minimize airborne dust from plant or haul roads and grounds:

    a. by the application of water any time the surface of the road is sufficiently dry to allow the creation of dust emissions by the act of wind or vehicular traffic;

    b. by reducing the speed of vehicular traffic to a point below that at which dust emissions are created;

    c. by paving;

    d. by the application of binders to the road surface at any time the road surface is found to allow the creation of dust emissions;

    Should one, or a combination, of the above methods fail to adequately reduce airborne dust from plant or haul roads and grounds, alternative methods shall be employed, either exclusively or in combination with one or all of the above control techniques, so that dust will not become airborne. Alternative methods shall be approved by the Department prior to utilization.

18. If this plant relocates to another site, this plant's Air Permit remains valid for this site unless or until it is revoked for failure to comply with ADEM Air Division Rules and Regulations. The owner or operator of this plant must provide written notification of the intent to relocate the plant to this site at least two weeks in advance. The written notification should include the planned construction beginning date and the projected startup date. Failure to provide this written notification is a violation of this permit condition and is grounds for revocation of this permit.

19. Any performance tests required shall be conducted and data reduced in accordance with the test methods and procedures contained in each specific permit condition unless the Director (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, or (3)

approves the use of an alternative method, the results of which he has determined to be adequate for indicating whether a specific source is in compliance.

20. The permittee shall not use as a defense in an enforcement action that maintaining compliance with conditions of this permit would have required halting or reducing the permitted activity.

21. The issuance of this permit does not convey any property rights of any sort, or any exclusive privilege.

22. The permittee shall keep this permit under file or on display at all times at the site where the facility for which the permit is issued is located and shall make the permit readily available for inspection by any or all persons who may request to see it.

23. The permittee shall submit an annual compliance certification to the Department no later than 60 days following the anniversary of the permittee's Title V permit..

    (a) The compliance certification shall include the following:

        a. The identification of each term or condition of this permit that is the basis of the certification;

        b. The compliance status;

        c. The method(s) used for determining the compliance status of the source, currently and over the reporting period consistent with Rule 335-3-16-.05(c) (Monitoring and Recordkeeping Requirements);

        d. Whether compliance has been continuous or intermittent; and

        e. Such other facts as the Department may require in order to determine the compliance status of the source.

    (b) The compliance certification shall be submitted to:

        Alabama Department of Environmental Management
        Air Division
        P.O. Box 301463
        Montgomery, AL 36130-1463

Kiln Nos. 3 & 4 with Baghouses & Common Stack (CA-03)

Provisos

	Regulations

Applicability

1. These sources are subject to the applicable requirements of ADEM Admin. Code r. 335-3-4-.01(1*), "Control of Particulate Emissions – Visible Emissions"*. — Rule 335-3-4-.01(1)

2. These sources are subject to the applicable requirements of ADEM Admin. Code r. 335-3-16-.03, *"Major Source Operating Permits"*. — Rule 335-3-16-.03

3. Kiln No. 4 (CA-03) is subject to a federally enforceable emission limit in order to comply with the applicable provisions of ADEM Admin. Code r. 335-3-14-.04, *"Air Permits Authorizing Construction in Clean Air Areas (Prevention of Significant Deterioration)"*. — Rule 335-3-14-.04 (BACT)

4. These sources are subject to the applicable requirements of 40 CFR Part 63, Subpart AAAAA, *"National Emission Standards for Hazardous Air Pollutants for Lime Manufacturing Plants"*. — Rule 335-3-11-.06(104) 40 CFR §63.7081 40 CFR §63.7082

5. These sources are subject to the provisions of 40 CFR Part 63, Subpart A, *"General Provisions"*, as specified in Table No. 9, *"Applicability of General Provisions to Subpart AAAAA"*. — 40 CFR §63.7140

6. These sources are subject to the applicable requirements of 40 CFR Part 64, *"Compliance Assurance Monitoring"*. — 40 CFR §64.2

Emission Standards

1. Visible emissions from these sources shall not exceed the opacity set by ADEM Admin. Code r. 335-3-4-.01(1). — Rule 335-3-4-.01(1)

2. Particulate matter (PM) emissions from Kiln No. 4 (CA-03) shall not exceed 0.39 pounds per ton of limestone feed (lb/tsf). — Rule 335-3-14-.04 (BACT)

3. In accordance with 40 CFR Part 63, Subpart AAAAA, *"Emissions Limitations"*, these sources shall comply with the following: — 40 CFR §63.7090

   (a) Each applicable emission limit specified in Table No. 1 of Subpart AAAAA. — 40 CFR §63.7090(a)

	Regulations
(b) Each applicable operating limit specified in Table No. 3 of Subpart AAAAA.	40 CFR §63.7090(b)
(c) Each applicable startup and shutdown period emission limit specified in Table No. 2 of Subpart AAAAA.	40 CFR §63.7090(c)
4. Natural gas shall make up at least 22% of total fuel usage, on a MMBtu basis, in Kiln Nos. 3 and 4 in any 12-month rolling period.	Rule 335-3-16-.05
5. Sulfur dioxide (SO$_2$) emissions from Kiln Nos. 3 and 4 combined shall not exceed 4,657 TPY in any 12-month rolling period as determined by a CEMS.	Rule 335-3-16-.05

Compliance and Performance Test Methods and Procedures

1. If testing is required, Method 5 of 40 CFR Part 60, Appendix A, shall be used in the determination of particulate matter (PM) emissions.	Rule 335-3-1-.05
2. If testing is required, Method 6 or 6A of 40 CFR Part 60, Appendix A, shall be used in the determination of sulfur dioxide (SO$_2$) emissions.	Rule 335-3-1-.05
3. If testing is required, Method 7 or 7E of 40 CFR Part 60, Appendix A, shall be used in the determination of nitrogen oxide (NO$_x$) emissions.	Rule 335-3-1-.05
4. If testing is required, Method 9 of 40 CFR Part 60, Appendix A, shall be used in the determination of opacity.	Rule 335-3-1-.05
5. If testing is required, Method 10 of 40 CFR Part 60, Appendix A, shall be used in the determination of carbon monoxide (CO) emissions.	Rule 335-3-1-.05
6. If testing is required, Method 25A of 40 CFR Part 60, Appendix A, shall be used in the determination of volatile organic compound (VOC) emissions.	Rule 335-3-1-.05
7. If testing is required, Method 321 of 40 CFR Part 60, Appendix A, shall be used in the determination of hydrogen chloride (HCl) emissions.	Rule 335-3-1-.05
8. These sources shall comply with the applicable requirements specified in 40 CFR Part 63, Subpart AAAAA, "*General Compliance Requirements*".	40 CFR §63.7100

	Regulations
9. These sources shall comply with the applicable requirements specified in 40 CFR Part 63, Subpart AAAAA, *"Testing and Initial Compliance Requirements"* (Table No. 4, *"Initial Compliance with Emission Limits"*, and Table No. 5, *"Requirements for Performance Tests"*).	40 CFR §63.7110 40 CFR §63.7111 40 CFR §63.7112 40 CFR §63.7114
10. Each affected source under 40 CFR Part 64 is also subject to a post-November 15, 1990, federal standard, 40 CFR Part 63, Subpart AAAAA. Emissions monitoring specified in Subpart AAAAA is considered *"presumptively acceptable monitoring"*, as specified in 40 CFR §64.4(b), *"Submittal Requirements"*.	40 CFR §64.4
11. By May 1, 2022, the permittee shall install, operate, maintain, and calibrate a continuous emissions monitoring system (CEMS) with a flow meter at a location approved by the Director in order to determine compliance with the applicable sulfur dioxide (SO_2) emissions standard. The CEMS and flow meter shall comply with the applicable specifications and procedures outlined in 40 CFR Part 75, Appendices A, B and C.	Rule 335-3-1-.04(1)

Emission Monitoring

	Regulations
1. Particulate matter (PM) emissions tests shall be conducted on each kiln at an interval not to exceed twelve months.	Rule 335-3-16-.05(c)(1)
2. These sources shall comply with the applicable compliance requirements specified in 40 CFR Part 63, Subpart AAAAA, *"Continuous Compliance Requirements"* (Table No. 6, *"Continuous Compliance with Operating Limits"*, and Table No. 7, *"Periodic Monitoring for Compliance with Opacity and Visible Emissions Limits"*).	40 CFR §63.7120 40 CFR §63.7121
3. By May 1, 2022, a certified continuous emissions monitoring system (CEMS) with a flow meter shall be used in the determination of sulfur dioxide (SO_2) emissions from the kilns.	Rule 335-3-1-.04(1)

Recordkeeping and Reporting Requirements

	Regulations
1. These sources shall comply with the applicable recordkeeping and reporting requirements specified in 40 CFR Part 63, Subpart AAAAA, *"Notification, Reports, and Records"* (Table No. 8 of Subpart AAAAA, *"Requirements for Reports"*).	40 CFR §63.7130 40 CFR §63.7131 40 CFR §63.7132 40 CFR §63.7133
2. All original data charts, performance evaluations, calibration checks, adjustments, and maintenance records for the CEMS and flow meter shall be kept in a permanent form suitable for	Rule 335-3-16-.05(c)(2)

	Regulations

inspection. These records shall be maintained for a period of at least five (5) years from the date of generation and shall be made available to the permitting authority upon request.

3. The permittee shall record the monthly fuel usage of each kiln in terms of MMBtu of each fuel type. The percentage of natural gas usage based on MMBtu during the previous 12-month period shall be calculated for each month within 10 days of the end of the month.

   Rule 335-3-16-.05(c)(2)

4. Quarterly excess emissions reports (EER) shall be submitted to the Department for each calendar quarter within the month following the end of the quarter. The reports shall include the following information:

   Rule 335-3-16-.05(c)(3)

   (a) The rolling 12-month natural gas usage (percentage of total fuel based on MMBtu) for Kiln Nos. 3 and 4 for each calendar month in the quarter;

   (b) The magnitude of SO_2 emissions for Kiln Nos. 3 and 4 in excess of the applicable emissions standard, as determined by the CEMS;

   (c) The date, time, and duration of each period of excess emissions;

   (d) The nature and cause of each period of excess emissions, if known;

   (e) Description of any corrective action or preventive measures implemented in response to excess emissions;

   (f) Data recorded during periods associated with monitor breakdowns, repairs, calibrations, and zero and span adjustments shall not be included in data averages;

   (g) The date and time of each period in which the CEMS was inoperative, excluding periods of zero and span checks, and the nature of any system repairs or adjustments performed;

   (h) During periods in which no excess emissions have occurred, the CEMS has not been inoperative, and/or repairs and adjustments were not necessary, such information shall be stated in the report;

   (i) The total source operating time (all times and periods in the appropriate averaging units, such as hours, days, minutes, etc.)

Regulations

(j) The total time the CEMS was available to record source performance. Information identifying each period during which the monitoring system was inoperative, excluding zero and span checks, and the nature of any system repairs or adjustments shall also be included;

(k) Monitor availability expressed as percent (%) of source operating time, calculated as follows:

$$\frac{\text{Total monitor availability time}}{\text{Total source operating time}} * 100\%$$

(l) Overall performance, expressed as percent (%), calculated as follows:

$$\frac{[(\text{Total monitor availability time}) - (\text{Total time of excess emissions})]}{(\text{Total monitor availability time})} * 100\%$$

(m) Statement of certification of truth, accuracy, and completeness; and

(n) Signature of the responsible official.

LANCE R. LEFLEUR
DIRECTOR

ADEM

KAY IVEY
GOVERNOR

Alabama Department of Environmental Management
adem.alabama.gov

1400 Coliseum Blvd. 36110-2400 ■ Post Office Box 301463
Montgomery, Alabama 36130-1463
(334) 271-7700 ■ FAX (334) 271-7950

September 21, 2021

Craig Gordinier
Plant Manager
Lhoist North America of Alabama, LLC – Montevallo Plant
7444 Highway 25 South
Calera, AL 35115

RE: Facility No.   411-0008
      Permit No.   X053

Dear Mr. Gordinier:

The enclosed Air Permit is issued pursuant to the Department's air pollution control rules and regulations. Please note the conditions which must be observed in order to retain this permit.

If you have any questions or require clarification of permit conditions, please contact Skyler Sanderson at (334) 270-5647 in Montgomery.

Sincerely,

Ronald W. Gore, Chief
Air Division

RWG/MSS

Enclosures

Birmingham Branch
110 Vulcan Road
Birmingham, AL 35209-4702
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Mobile-Coastal
3664 Dauphin Street, Suite B
Mobile, AL 36608
(251) 304-1176
(251) 304-1189 (FAX)

ADEM

Alabama Department of Environmental Management

AIR PERMIT

PERMITTEE: LHOIST NORTH AMERICA OF ALABAMA, LLC

FACILITY NAME: MONTEVALLO PLANT

LOCATION: CALERA, AL

PERMIT NUMBER	DESCRIPTION OF EQUIPMENT, ARTICLE, OR DEVICE
411-0008-X053	Kiln No. 3 controlled by Baghouse No. BH-0303 & Kiln No. 4 controlled by Baghouse No. BH-0403 with Common Stack (CA-03)

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ISSUANCE DATE: September 21, 2021

_____
Alabama Department of Environmental Management

Page 1 of   10

General Permit Provisos

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2. This permit is not transferable. Upon sale or legal transfer, the new owner or operator must apply for a permit within 30 days.

3. A new permit application must be made for new sources, replacements, alterations or design changes which may result in the issuance of, or an increase in the issuance of, air contaminants, or the use of which may eliminate or reduce or control the issuance of air contaminants.

4. Each point of emission, which requires testing, will be provided with sampling ports, ladders, platforms, and other safety equipment to facilitate testing performed in accordance with procedures established by Part 60 of Title 40 of the Code of Federal Regulations, as the same may be amended or revised.

5. All air pollution control equipment shall be operated at all times while this process is operational. In the event of scheduled maintenance, unscheduled maintenance, or a breakdown of the pollution control equipment, the process shall be shutdown as expeditiously as possible (unless this act and subsequent re-start would clearly cause greater emissions than continuing operations of the process for a short period). The Department shall be notified of all such events **that exceed 1 hour** within 24 hours. The notification shall include all pertinent facts, including the duration of the process operating without the control device and the level of excess emissions which have occurred. Records of all such events, regardless of reporting requirements, shall be made and maintained for a period of five years. These records shall be available for inspection.

6. In the event there is a breakdown of air pollution control or process equipment in such a manner as to cause increased emission of air contaminants for a period greater than **1 hour**, the person responsible for such equipment shall notify the Air Division within 24 hours and provide a statement giving all pertinent facts, including the duration of the breakdown. The Air Division shall be notified when the breakdown has been corrected.

7. All deviations from requirements within this permit shall be reported to the Department within 48 hours of the deviation or by the next work day while providing a statement with regards to the date, time, duration, cause, and corrective actions taken to bring the sources back into compliance.

8. This process, including all air pollution control devices and capture systems for which this permit is issued, shall be maintained and operated at all times in a manner so as to minimize the emissions of air contaminants. Procedures for ensuring that the above equipment is properly operated and maintained so as to minimize the emission of air contaminants shall be established.

9. This permit expires and the application is cancelled if construction has not begun within 24 months of the date of issuance of the permit.

10. On completion of construction of the device(s) for which this permit is issued, written notification of the fact is to be submitted to the Chief of the Air Division. The notification shall indicate whether the device(s) was constructed as proposed in the application. The device(s) shall not be operated until authorization to operate is granted by the Chief of the Air Division. Failure to notify the Chief of the Air Division of completion of construction and/or operation without authorization could result in revocation of this permit.

11. Submittal of other reports regarding monitoring records, fuel analyses, operating rates, and equipment malfunctions may be required as authorized in the Department's air pollution control rules and regulations. The Department may require stack emission testing at any time.

12. Additions and revisions to the conditions of this Permit will be made, if necessary, to ensure that the Department's air pollution control rules and regulations are not violated.

13. Nothing in this permit or conditions thereto shall negate any authority granted to the Air Division pursuant to the Alabama Environmental Management Act or regulations issued thereunder.

14. This permit is issued with the condition that, should obnoxious odors arising from the plant operations be verified by Air Division inspectors, measures to abate the odorous emissions shall be taken upon a determination by the Alabama Department of Environmental Management that these measures are technically and economically feasible.

15. The Air Division must be notified in writing at least 10 working days in advance of all emission tests to be conducted and submitted as proof of compliance with the Department's air pollution control rules and regulations.

    To avoid problems concerning testing methods and procedures, the following shall be included with the notification letter:

    a. The date the test crew is expected to arrive, the date and time anticipated of the start of the first run, how many and which sources are to be tested, and the names of the persons and/or testing company that will conduct the tests.

    b. A complete description of each sampling train to be used, including type of media used in determining gas stream components, type of probe lining, type of filter media, and probe cleaning method and solvent to be used (if test procedure requires probe cleaning).

    c. A description of the process(es) to be tested, including the feed rate, any operating parameter used to control or influence the operations, and the rated capacity.

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A pretest meeting may be held at the request of the source owner or the Department. The necessity for such a meeting and the required attendees will be determined on a case-by-case basis.

All test reports must be submitted to the Air Division within 30 days of the actual completion of the test, unless an extension of time is specifically approved by the Air Division.

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17. Precautions shall be taken to prevent fugitive dust emanating from plant roads, grounds, stockpiles, screens, dryers, hoppers, ductwork, etc.

    Plant or haul roads and grounds will be maintained in the following manner so that dust will not become airborne. A minimum of one, or a combination, of the following methods shall be utilized to minimize airborne dust from plant or haul roads and grounds:

    a. by the application of water any time the surface of the road is sufficiently dry to allow the creation of dust emissions by the act of wind or vehicular traffic;

    b. by reducing the speed of vehicular traffic to a point below that at which dust emissions are created;

    c. by paving;

    d. by the application of binders to the road surface at any time the road surface is found to allow the creation of dust emissions;

    Should one, or a combination, of the above methods fail to adequately reduce airborne dust from plant or haul roads and grounds, alternative methods shall be employed, either exclusively or in combination with one or all of the above control techniques, so that dust will not become airborne. Alternative methods shall be approved by the Department prior to utilization.

18. If this plant relocates to another site, this plant's Air Permit remains valid for this site unless or until it is revoked for failure to comply with ADEM Air Division Rules and Regulations. The owner or operator of this plant must provide written notification of the intent to relocate the plant to this site at least two weeks in advance. The written notification should include the planned construction beginning date and the projected startup date. Failure to provide this written notification is a violation of this permit condition and is grounds for revocation of this permit.

19. Any performance tests required shall be conducted and data reduced in accordance with the test methods and procedures contained in each specific permit condition unless the Director (1) specifies or approves, in specific cases, the use of a reference method with minor changes in methodology, (2) approves the use of an equivalent method, or (3)

approves the use of an alternative method, the results of which he has determined to be adequate for indicating whether a specific source is in compliance.

20. The permittee shall not use as a defense in an enforcement action that maintaining compliance with conditions of this permit would have required halting or reducing the permitted activity.

21. The issuance of this permit does not convey any property rights of any sort, or any exclusive privilege.

22. The permittee shall keep this permit under file or on display at all times at the site where the facility for which the permit is issued is located and shall make the permit readily available for inspection by any or all persons who may request to see it.

23. The permittee shall submit an annual compliance certification to the Department no later than 60 days following the anniversary of the permittee's Title V permit..

    (a) The compliance certification shall include the following:

        a. The identification of each term or condition of this permit that is the basis of the certification;

        b. The compliance status;

        c. The method(s) used for determining the compliance status of the source, currently and over the reporting period consistent with Rule 335-3-16-.05(c) (Monitoring and Recordkeeping Requirements);

        d. Whether compliance has been continuous or intermittent; and

        e. Such other facts as the Department may require in order to determine the compliance status of the source.

    (b) The compliance certification shall be submitted to:

    Alabama Department of Environmental Management
    Air Division
    P.O. Box 301463
    Montgomery, AL 36130-1463

Kiln Nos. 3 & 4 with Baghouses & Common Stack (CA-03)

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Applicability

1. These sources are subject to the applicable requirements of ADEM Admin. Code r. 335-3-4-.01(1), *"Control of Particulate Emissions – Visible Emissions"*.	Rule 335-3-4-.01(1)
2. These sources are subject to the applicable requirements of ADEM Admin. Code r. 335-3-16-.03, *"Major Source Operating Permits"*.	Rule 335-3-16-.03
3. Kiln No. 4 (CA-03) is subject to a federally enforceable emission limit in order to comply with the applicable provisions of ADEM Admin. Code r. 335-3-14-.04, *"Air Permits Authorizing Construction in Clean Air Areas (Prevention of Significant Deterioration)"*.	Rule 335-3-14-.04 (BACT)
4. These sources are subject to the applicable requirements of 40 CFR Part 63, Subpart AAAAA, *"National Emission Standards for Hazardous Air Pollutants for Lime Manufacturing Plants"*.	Rule 335-3-11-.06(104) 40 CFR §63.7081 40 CFR §63.7082
5. These sources are subject to the provisions of 40 CFR Part 63, Subpart A, *"General Provisions"*, as specified in Table No. 9, *"Applicability of General Provisions to Subpart AAAAA"*.	40 CFR §63.7140
6. These sources are subject to the applicable requirements of 40 CFR Part 64, *"Compliance Assurance Monitoring"*.	40 CFR §64.2

Emission Standards

1. Visible emissions from these sources shall not exceed the opacity set by ADEM Admin. Code r. 335-3-4-.01(1).	Rule 335-3-4-.01(1)
2. Particulate matter (PM) emissions from Kiln No. 4 (CA-03) shall not exceed 0.39 pounds per ton of limestone feed (lb/tsf).	Rule 335-3-14-.04 (BACT)
3. In accordance with 40 CFR Part 63, Subpart AAAAA, *"Emissions Limitations"*, these sources shall comply with the following:	40 CFR §63.7090
(a) Each applicable emission limit specified in Table No. 1 of Subpart AAAAA.	40 CFR §63.7090(a)

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(b) Each applicable operating limit specified in Table No. 3 of Subpart AAAAA.	40 CFR §63.7090(b)
(c) Each applicable startup and shutdown period emission limit specified in Table No. 2 of Subpart AAAAA.	40 CFR §63.7090(c)
4. Natural gas shall make up at least 22% of total fuel usage, on a MMBtu basis, in Kiln Nos. 3 and 4 in any 12-month rolling period.	Rule 335-3-16-.05
5. Sulfur dioxide (SO_2) emissions from Kiln Nos. 3 and 4 combined shall not exceed 4,657 TPY in any 12-month rolling period as determined by a CEMS.	Rule 335-3-16-.05

Compliance and Performance Test Methods and Procedures

1. If testing is required, Method 5 of 40 CFR Part 60, Appendix A, shall be used in the determination of particulate matter (PM) emissions.	Rule 335-3-1-.05
2. If testing is required, Method 6 or 6A of 40 CFR Part 60, Appendix A, shall be used in the determination of sulfur dioxide (SO_2) emissions.	Rule 335-3-1-.05
3. If testing is required, Method 7 or 7E of 40 CFR Part 60, Appendix A, shall be used in the determination of nitrogen oxide (NO_x) emissions.	Rule 335-3-1-.05
4. If testing is required, Method 9 of 40 CFR Part 60, Appendix A, shall be used in the determination of opacity.	Rule 335-3-1-.05
5. If testing is required, Method 10 of 40 CFR Part 60, Appendix A, shall be used in the determination of carbon monoxide (CO) emissions.	Rule 335-3-1-.05
6. If testing is required, Method 25A of 40 CFR Part 60, Appendix A, shall be used in the determination of volatile organic compound (VOC) emissions.	Rule 335-3-1-.05
7. If testing is required, Method 321 of 40 CFR Part 60, Appendix A, shall be used in the determination of hydrogen chloride (HCl) emissions.	Rule 335-3-1-.05
8. These sources shall comply with the applicable requirements specified in 40 CFR Part 63, Subpart AAAAA, "*General Compliance Requirements*".	40 CFR §63.7100

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9. These sources shall comply with the applicable requirements specified in 40 CFR Part 63, Subpart AAAAA, *"Testing and Initial Compliance Requirements"* (Table No. 4, *"Initial Compliance with Emission Limits"*, and Table No. 5, *"Requirements for Performance Tests"*).	40 CFR §63.7110 40 CFR §63.7111 40 CFR §63.7112 40 CFR §63.7114
10. Each affected source under 40 CFR Part 64 is also subject to a post-November 15, 1990, federal standard, 40 CFR Part 63, Subpart AAAAA. Emissions monitoring specified in Subpart AAAAA is considered *"presumptively acceptable monitoring",* as specified in 40 CFR §64.4(b), *"Submittal Requirements"*.	40 CFR §64.4
11. By May 1, 2022, the permittee shall install, operate, maintain, and calibrate a continuous emissions monitoring system (CEMS) with a flow meter at a location approved by the Director in order to determine compliance with the applicable sulfur dioxide (SO_2) emissions standard. The CEMS and flow meter shall comply with the applicable specifications and procedures outlined in 40 CFR Part 75, Appendices A, B and C.	Rule 335-3-1-.04(1)

Emission Monitoring

1. Particulate matter (PM) emissions tests shall be conducted on each kiln at an interval not to exceed twelve months.	Rule 335-3-16-.05(c)(1)
2. These sources shall comply with the applicable compliance requirements specified in 40 CFR Part 63, Subpart AAAAA, *"Continuous Compliance Requirements"* (Table No. 6, *"Continuous Compliance with Operating Limits"*, and Table No. 7, *"Periodic Monitoring for Compliance with Opacity and Visible Emissions Limits"*).	40 CFR §63.7120 40 CFR §63.7121
3. By May 1, 2022, a certified continuous emissions monitoring system (CEMS) with a flow meter shall be used in the determination of sulfur dioxide (SO_2) emissions from the kilns.	Rule 335-3-1-.04(1)

Recordkeeping and Reporting Requirements

1. These sources shall comply with the applicable recordkeeping and reporting requirements specified in 40 CFR Part 63, Subpart AAAAA, *"Notification, Reports, and Records"* (Table No. 8 of Subpart AAAAA, *"Requirements for Reports"*).	40 CFR §63.7130 40 CFR §63.7131 40 CFR §63.7132 40 CFR §63.7133
2. All original data charts, performance evaluations, calibration checks, adjustments, and maintenance records for the CEMS and flow meter shall be kept in a permanent form suitable for	Rule 335-3-16-.05(c)(2)

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inspection. These records shall be maintained for a period of at least five (5) years from the date of generation and shall be made available to the permitting authority upon request.

3. The permittee shall record the monthly fuel usage of each kiln in terms of MMBtu of each fuel type. The percentage of natural gas usage based on MMBtu during the previous 12-month period shall be calculated for each month within 10 days of the end of the month.

Rule 335-3-16-.05(c)(2)

4. Quarterly excess emissions reports (EER) shall be submitted to the Department for each calendar quarter within the month following the end of the quarter. The reports shall include the following information:

Rule 335-3-16-.05(c)(3)

(a) The rolling 12-month natural gas usage (percentage of total fuel based on MMBtu) for Kiln Nos. 3 and 4 for each calendar month in the quarter;

(b) The magnitude of SO_2 emissions for Kiln Nos. 3 and 4 in excess of the applicable emissions standard, as determined by the CEMS;

(c) The date, time, and duration of each period of excess emissions;

(d) The nature and cause of each period of excess emissions, if known;

(e) Description of any corrective action or preventive measures implemented in response to excess emissions;

(f) Data recorded during periods associated with monitor breakdowns, repairs, calibrations, and zero and span adjustments shall not be included in data averages;

(g) The date and time of each period in which the CEMS was inoperative, excluding periods of zero and span checks, and the nature of any system repairs or adjustments performed;

(h) During periods in which no excess emissions have occurred, the CEMS has not been inoperative, and/or repairs and adjustments were not necessary, such information shall be stated in the report;

(i) The total source operating time (all times and periods in the appropriate averaging units, such as hours, days, minutes, etc.)

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(j) The total time the CEMS was available to record source performance. Information identifying each period during which the monitoring system was inoperative, excluding zero and span checks, and the nature of any system repairs or adjustments shall also be included;

(k) Monitor availability expressed as percent (%) of source operating time, calculated as follows:

$$\frac{\text{Total monitor availability time}}{\text{Total source operating time}} * 100\%$$

(l) Overall performance, expressed as percent (%), calculated as follows:

$$\frac{[(\text{Total monitor availability time})-(\text{Total time of excess emissions})]}{(\text{Total monitor availability time})} * 100\%$$

(m) Statement of certification of truth, accuracy, and completeness; and

(n) Signature of the responsible official.