Control Method:	(A) Baghouse
Est. % Efficiency:	
Cost Effectiveness:	0 $/ton
Incremental Cost Effectiveness:	0 $/ton
Compliance Verified:	Unknown
Pollutant/Compliance Notes:	Compliance using the methods for BACT PM, SO2 and NOX shall indicate compliance with BACT for PM10 and PM2.5.

POLLUTANT NAME:	Visible Emissions (VE)
CAS Number:	VE
Test Method:	Other
Other Test Method:	Continuous opacity monitor
Pollutant Group(s):	
Emission Limit 1:	15.0000 % OPACITY NTE 15% IN ANY 6-MIN BLOCK
Emission Limit 2:	
Standard Emission:	

Did factors, other then air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis:	BACT-PSD
Other Applicable Requirements:	
Control Method:	(A) Baghouse
Est. % Efficiency:	
Cost Effectiveness:	0 $/ton
Incremental Cost Effectiveness:	0 $/ton
Compliance Verified:	Unknown
Pollutant/Compliance Notes:	COMS in lieu of bag leak detection system or PM detector, per NESHAP Subpart AAAAA

Process/Pollutant Information

PROCESS NAME:	Material Handling Operations
Process Type:	90.019 (Lime/Limestone Handling/Kilns/Storage/Manufacturing)
Primary Fuel:	
Throughput:	0
Process Notes:	a. Limestone Handling and Storage Process, including: conveyors; surge hopper; pan feeders; enclosed building containing a screen used to segregate limestone according to size and transferred into a charging bin; two enclosures containing surge bins; reject bin; load-out weigh bins; truck loadout area; two mechanical (blower) rooms; and baghouses throughout the process. b. Lime Handling, Crushing, Rejects, and Lime Kiln Dust Process, including: four hoppers each equipped with a pan feeder; conveyors; vents; an enclosed building containing 2-deck screen, 4-roller crusher and baghouse; two weigh bins; two rotary feeders; blowers; a kiln reject dust bin; two portable tote containers; rotary feeder; truck loadout area; and baghouses throughout the process. c. Lime Handling, Screening and Storage Process, including: vents; conveyors, an enclosed building containing a 3-deck screen and a

baghouse; chute magnets; lime bins equipped with a self contained dustless truck loading spout; an enclosure containing a silo truck load-out area equipped with a truck scale; railcar load-out area; and baghouses throughout the process. d. Fuel Handling Processes: (1) Wood Grinding System, including: walking floor truck and screw conveyor area; raw wood storage bin; conveyors; an enclosure containing a mill; CO2 systems; ground chip storage, shared ribbon mixer, dosing bin, blowers, baghouses; and a stack. (2) Petroleum Coke/Coal Grinding System, including: front-end loader/dump truck area; dump hopper; conveyors; feeders; petroleum coke and coal storage bin; an enclosure containing bowl mill, 3.5 Million British thermal units/hour (MMBtu/hour) heater; CO2 systems; ground coke bin, dosing bin; shared ribbon mixer; blowers; baghouses; and a stack.

POLLUTANT NAME:	Visible Emissions (VE)
CAS Number:	VE
Test Method:	EPA/OAR Mthd 22
Pollutant Group(s):	
Emission Limit 1:	5.0000 % OPACITY
Emission Limit 2:	
Standard Emission:	

Did factors, other then air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis:	BACT-PSD
Other Applicable Requirements:	NSPS , NESHAP
Control Method:	(A) Wet suppression, fabric filters, partial enclosure, and enclosure to reduce PM and visible emissions. Baghouse must have design removal efficiency of at least 99%.
Est. % Efficiency:	
Cost Effectiveness:	0 $/ton
Incremental Cost Effectiveness:	0 $/ton
Compliance Verified:	Unknown
Pollutant/Compliance Notes:	NSPS OOO and NESHAP AAAAA prescribe 7% opacity standard. The compliance procedures specified by NSPS Subpart OOO and NESHAP Subpart AAAAA shall be used to demonstrate compliance with 5% opacity (instead of 7%).

Facility Information

RBLC ID:	PA-0283 (final)	**Date Determination Last Updated:**	01/29/2018
Corporate/Company Name:	GRAYMONT PA INC	**Permit Number:**	14-00002N
Facility Name:	GRAYMONT PA INC/PLEASANT GAP & BELLEFONTE PLTS	**Permit Date:**	11/19/2012 (actual)
Facility Contact:	JOHN MAITLAND 814-353-2106	**FRS Number:**	25-1527520-1
Facility Description:	This plan approval is for the Kiln No. 8 project. WASTE OIL HEATER [BEL], PROPANE HEATER, PULVERIZED LIMESTONE SYSTEM, 136 HP DIESEL GENERATOR [PG], MISCELLANEOUS EMERGENCY GENERATORS, KILN NO. 8 PROJECT STONE RECLAMATION SYSTEM, PROCESSED STONE HANDLING, LIME KILN DUST HANDLING AND LOADING SYSTEM, LIME HANDLING AND STORAGE SYSTEM, LIME LOADING SYSTEM, EMERGENCY GENERATOR-ENGINES FOR COOLING FANS, PLS FABRIC COLLECTOR, ROTARY DRYER FABRIC COLLECTOR, STONE RECLAMATION FABRIC COLLECTOR, PROCESSED STONE AND LKD FABRIC COLLECTOR, LIME HANDLING AND STORAGE FABRIC COLLECTOR, LIME LOADING FABRIC COLLECTOR, KILN 6 BAGHOUSE, LIME	**SIC Code:**	3274

KILN 7 SEMI-WET SCRUBBER, LIME KILN 7 FABRIC COLLECTOR, KILN NO. 8 BAGHOUSE NATURAL GAS SUPPLY BITUMINOUS COAL SUPPLY PETROLEUM COKE SUPPLY NO. 2 FUEL OIL STORAGE PROPANE STORAGE DIESEL FUEL STORAGE SPACE HEATER EXHAUSTS PLS FABRIC COLLECTOR STACK DRYER FABRIC COLLECTOR STACK GENERATOR STACK MISC EMERGENCY GENERATORS STACKS FABRIC COLLECTOR VENT FABRIC COLLECTOR STACK FABRIC COLLECTOR STACK FABRIC COLLECTOR STACK GENERATOR-ENGINE STACKS KILN 6 STACK LIME KILN 7 STACK KILN NO. 8 STACK PROPANE HEATER EMISSIONS

Permit Type: U: Unspecified **NAICS Code:** 327410

Permit URL:

EPA Region: 3 **COUNTRY:** USA

Facility County: CENTRE

Facility State: PA

Facility ZIP Code: 16823

Permit Issued By: PENNSYLVANIA DEPT OF ENVIRONMENTAL PROTECTION, BUREAU OF AIR QUALITY (Agency Name)
MR. ROBERT COOK(Agency Contact) (717)772-3974 rwcook@pa.gov

Other Agency Contact Info: MUHAMMAD Q. ZAMAN,
ENVIRONMENTAL PROGRAM MANAGER, NORTHCENTRAL REGION
570-327-3648

Permit Notes: Pursuant to the plantwide applicability limit (PAL) provisions of 40 CFR § 52.21(aa)(7), the total combined sulfur dioxide (SO_2) emissions, including fugitive emissions, from the facility shall not exceed 302.6 tons in any 12 consecutive month period.

Facility-wide Emissions:

Pollutant Name:	Facility-wide Emissions Increase:
Sulfur Oxides (SOx)	302.6000 (Tons/Year)
Volatile Organic Compounds (VOC)	50.0000 (Tons/Year)

Process/Pollutant Information

PROCESS NAME: KILN NO. 8

Process Type: 90.019 (Lime/Limestone Handling/Kilns/Storage/Manufacturing)

Primary Fuel: Pipeline quality natural gas

Throughput: 0

Process Notes: Source ID P418 consists of a 660 tons per day, twin-shaft vertical lime kiln, designated as Kiln No. 8, that is equipped with 66 natural gas fuel delivery lances (2 sets of 33) with a total approximate heat input (HHV) equal to 100.4 MMBtu/hr. The air contaminant emissions from the kiln shall be controlled by the installation of ID C418 which is a pulse jet fabric collector, designated as 328-PDC-870. The fabric collector shall have a minimum fabric area of 25,536 square feet and handle no more than 75,000 actual cubic feet per minute. The permittee shall install, maintain, certify and operate a continuous emission monitoring system (CEMS) for nitrogen oxides (expressed as NO_2), carbon monoxide, and sulfur oxides (expressed as SO_2) emissions and opacity monitoring.

POLLUTANT NAME: Particulate matter, total (TPM)

CAS Number: PM

Test Method: EPA/OAR Mthd 17 and 202

Pollutant Group(s): (Particulate Matter (PM))

Emission Limit 1: 2.2500 LB/H FILTERABLE AND CONDESABILE PM
Emission Limit 2: 0.0040 GRAIN/DSCF FILTERABLE PM
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: OTHER CASE-BY-CASE
Other Applicable Requirements: OTHER
Control Method: (A) Baghouse
Est. % Efficiency:
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Particulate matter, filterable < 10 µ (FPM10)
CAS Number: PM
Test Method: Unspecified
Pollutant Group(s): (Particulate Matter (PM))
Emission Limit 1: 0.0030 GRAINS/DSCF FILTERABLE
Emission Limit 2: 1.9100 LB/H FILTERABLE AND CONDENSABLE
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: OTHER CASE-BY-CASE
Other Applicable Requirements: OTHER
Control Method: (A) Baghouse
Est. % Efficiency:
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Particulate matter, total < 2.5 µ (TPM2.5)
CAS Number: PM
Test Method: Unspecified
Pollutant Group(s): (Particulate Matter (PM))
Emission Limit 1: 0.0020 GRAINS/DSCF FILTERABLE
Emission Limit 2: 1.5600 LB/H FILTERABLE AND CONDENSABLE
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: OTHER CASE-BY-CASE

Other Applicable Requirements: OTHER
Control Method: (A) Baghouse
Est. % Efficiency:
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Sulfur Oxides (SOx)
CAS Number: 7446
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds , Oxides of Sulfur (SOx))
Emission Limit 1: 23.0000 LB/H ROLLING 30-DAY AVERAGE
Emission Limit 2:
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: OTHER CASE-BY-CASE
Other Applicable Requirements: OTHER
Control Method: (N)
Est. % Efficiency:
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Visible Emissions (VE)
CAS Number: VE
Test Method: Unspecified
Pollutant Group(s):
Emission Limit 1: 10.0000 % OPACITY FOR ANY 6-MINUTE BLOCK PERIOD
Emission Limit 2: 20.0000 % OPACITY 20-60% FOR ANY 3-MINUTE BLOCK PERIOD
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: OTHER CASE-BY-CASE
Other Applicable Requirements: OTHER
Control Method: (N)
Est. % Efficiency:
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton

Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Volatile Organic Compounds (VOC)
CAS Number: VOC
Test Method: Unspecified
Pollutant Group(s): (Volatile Organic Compounds (VOC))
Emission Limit 1: 0.1000 LB/TON OF LIME
Emission Limit 2:
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: OTHER CASE-BY-CASE
Other Applicable Requirements: OTHER
Control Method: (N)
Est. % Efficiency:
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Nitrogen Oxides (NOx)
CAS Number: 10102
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds , Oxides of Nitrogen (NOx) , Particulate Matter (PM))
Emission Limit 1: 7.9000 LB/H ROLLING 30-DAY AVERAGE
Emission Limit 2: 34.6000 T/YR IN ANY 12 CONSECUTIVE MONTH PERIOD
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: OTHER CASE-BY-CASE
Other Applicable Requirements: OTHER
Control Method: (N)
Est. % Efficiency:
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes: Expressed as NO2

POLLUTANT NAME: Carbon Monoxide
CAS Number: 630-08-0

Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds)
Emission Limit 1: 6.9600 LB/H ROLLING 30-DAY AVERAGE
Emission Limit 2: 26.5000 T/YR ANY 12 CONSECUTIVE MONTH PERIOD
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: OTHER CASE-BY-CASE
Other Applicable Requirements: OTHER
Control Method: (N)
Est. % Efficiency:
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Methane
CAS Number: 74-82-8
Test Method: Unspecified
Pollutant Group(s): (Greenhouse Gasses (GHG) , Organic Compounds (all) , Organic Non-HAP Compounds)
Emission Limit 1: 3.6500 MMBTU/TON LIME (HHV)
Emission Limit 2:
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements: NSPS
Control Method: (N)
Est. % Efficiency:
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Sulfur Dioxide (SO2)
CAS Number: 7446-09-5
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds , Oxides of Sulfur (SOx))
Emission Limit 1: 500.0000 PPMVD 1-HOUR BLOCK AVERAGE
Emission Limit 2:
Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis:	OTHER CASE-BY-CASE
Other Applicable Requirements:	OTHER
Control Method:	(N)
Est. % Efficiency:	
Cost Effectiveness:	0 $/ton
Incremental Cost Effectiveness:	0 $/ton
Compliance Verified:	Unknown
Pollutant/Compliance Notes:	

Facility Information

RBLC ID:	TX-0726 (final)	**Date Determination Last Updated:**	05/16/2016
Corporate/Company Name:	CHEMICAL LIME, LTD	**Permit Number:**	7808 AND PSD-TX-256M3
Facility Name:	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	**Permit Date:**	02/22/2010 (actual)
Facility Contact:	STEVEN CURRERI (817) 806-1548	**FRS Number:**	110001866712
Facility Description:	Chemical Lime operates a lime production plant in Comal County consisting of two operational kilns: Kiln 2 and Kiln 3. Kiln 2 (and associated supporting equipment) is authorized under Permit 5640A; Kiln 3 (and associated supporting equipment) is authorized under Permit 7808. Both kilns are authorized under a federal Prevention of Significant Deterioration (PSD) permit; this modification to the PSD permit will make the current permit number PSDTX256M3. Limestone is quarried on-site or delivered from off-site sources, crushed to specific size requirements, and charged to the kilns along with coal, coke and/or natural gas to produce the product lime. The quarry is owned by Chemical Lime, but is currently operated under separate permits by an independent contractor. After exiting the kilns, the product lime is cooled and transferred to silos for intermediate storage. At this point, the lime is either sized to customer specifications or is hydrated and then shipped. Product lime is transported from the plant by rail and truck. Lime is also packaged in bulk bags and shipped by truck to customers. Hydrated product is shipped in bulk or bags.	**SIC Code:**	3274
Permit Type:	C: Modify process at existing facility	**NAICS Code:**	327410
Permit URL:			
EPA Region:	6	**COUNTRY:**	USA
Facility County:	COMAL		
Facility State:	TX		
Facility ZIP Code:	78132		
Permit Issued By:	TEXAS COMMISSION ON ENVIRONMENTAL QUALITY (TCEQ) (Agency Name) MICHAEL PARTEE(Agency Contact) (512) 239-3312 michael.partee@tceq.texas.gov		
Other Agency Contact Info:	Tan Nguyen 512-239-3445		
Permit Notes:			

Affected Boundaries:	**Boundary Type:**	**Class 1 Area State:**	**Boundary:**	**Distance:**

CLASS1 TX Big Bend NP > 250 km

Process/Pollutant Information

PROCESS NAME: Rotary Kiln 2

Process Type: 90.019 (Lime/Limestone Handling/Kilns/Storage/Manufacturing)

Primary Fuel: natural gas, coal, and petroleum coke

Throughput: 504.00 tons per day

Process Notes:

POLLUTANT NAME: Nitrogen Oxides (NOx)

CAS Number: 10102

Test Method: Unspecified

Pollutant Group(s): (InOrganic Compounds , Oxides of Nitrogen (NOx) , Particulate Matter (PM))

Emission Limit 1: 5.0000 LB/TON OF LIME PROD

Emission Limit 2:

Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (N)

Est. % Efficiency:

Cost Effectiveness: 0 $/ton

Incremental Cost Effectiveness: 0 $/ton

Compliance Verified: Unknown

Pollutant/Compliance Notes:

POLLUTANT NAME: Sulfur Dioxide (SO2)

CAS Number: 7446-09-5

Test Method: Unspecified

Pollutant Group(s): (InOrganic Compounds , Oxides of Sulfur (SOx))

Emission Limit 1:

Emission Limit 2:

Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (A) Limiting the fuel sulfur input, in addition to the dry scrubbing inherent in these systems.

Est. % Efficiency: 92.000

Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Particulate matter, total < 10 µ (TPM10)
CAS Number: PM
Test Method: Unspecified
Pollutant Group(s): (Particulate Matter (PM))
Emission Limit 1:
Emission Limit 2:
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:
Control Method: (A) The use of fabric filter to achieve a 0.01 gr/dscf filterable and condensable PM10.
Est. % Efficiency:
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Sulfuric Acid (mist, vapors, etc)
CAS Number: 7664-93-9
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds , Particulate Matter (PM))
Emission Limit 1:
Emission Limit 2:
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:
Control Method: (P) Proper kiln design and operation.
Est. % Efficiency:
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Carbon Monoxide

CAS Number: 630-08-0

Test Method: Unspecified

Pollutant Group(s): (InOrganic Compounds)

Emission Limit 1: 3.0000 LB/TON FEED

Emission Limit 2:

Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (P) Proper kiln design and operation (good engineering practice/best management practice) to minimize the products of incomplete combustion.

Est. % Efficiency:

Cost Effectiveness: 0 $/ton

Incremental Cost Effectiveness: 0 $/ton

Compliance Verified: Unknown

Pollutant/Compliance Notes:

Process/Pollutant Information

PROCESS NAME: Rotary Kiln 3

Process Type: 90.019 (Lime/Limestone Handling/Kilns/Storage/Manufacturing)

Primary Fuel: natural gas, coal, and petroleum coke

Throughput: 850.00 tons per day

Process Notes:

POLLUTANT NAME: Nitrogen Oxides (NOx)

CAS Number: 10102

Test Method: Unspecified

Pollutant Group(s): (InOrganic Compounds , Oxides of Nitrogen (NOx) , Particulate Matter (PM))

Emission Limit 1: 2.6000 LB/TON OF LIME PROD

Emission Limit 2:

Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: U

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (N)

Est. % Efficiency:

Cost Effectiveness: 0 $/ton

Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Sulfur Dioxide (SO2)
CAS Number: 7446-09-5
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds , Oxides of Sulfur (SOx))
Emission Limit 1:
Emission Limit 2:
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:
Control Method: (A) Limiting the fuel sulfur input, in addition to the dry scrubbing inherent in these systems.
Est. % Efficiency: 92.000
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Particulate matter, total < 10 µ (TPM10)
CAS Number: PM
Test Method: Unspecified
Pollutant Group(s): (Particulate Matter (PM))
Emission Limit 1:
Emission Limit 2:
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:
Control Method: (A) The use of fabric filter to achieve a 0.01 gr/dscf filterable and condensable PM10.
Est. % Efficiency:
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Sulfuric Acid (mist, vapors, etc)

CAS Number: 7664-93-9
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds , Particulate Matter (PM))
Emission Limit 1:
Emission Limit 2:
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:
Control Method: (P) Proper kiln design and operation.
Est. % Efficiency:
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

POLLUTANT NAME: Carbon Monoxide
CAS Number: 630-08-0
Test Method: Unspecified
Pollutant Group(s): (InOrganic Compounds)
Emission Limit 1: 2.2000 LB/TON FEED
Emission Limit 2:
Standard Emission:
Did factors, other then air pollution technology considerations influence the BACT decisions: U
Case-by-Case Basis: BACT-PSD
Other Applicable Requirements:
Control Method: (P) Proper kiln design and operation (good engineering practice/best management practice) to minimize the products of incomplete combustion.
Est. % Efficiency:
Cost Effectiveness: 0 $/ton
Incremental Cost Effectiveness: 0 $/ton
Compliance Verified: Unknown
Pollutant/Compliance Notes:

Facility Information

RBLC ID: WI-0250 (final)
Date Determination
Last Updated: 10/26/2009
Corporate/Company Name: GRAYMONT (WI) LLC
Permit Number: 08-DCF-103

Facility Name:	GRAYMONT (WI) LLC	**Permit Date:**	02/06/2009 (actual)
Facility Contact:	PHIL MARQUIS 7153925146 PMARQUIS@GRAYMONT.COM	**FRS Number:**	UNKNOWN
Facility Description:	LIME MANUFACTURING FACILITY (FORMER CLM)	**SIC Code:**	3274
Permit Type:	A: New/Greenfield Facility	**NAICS Code:**	327410
Permit URL:			
EPA Region:	5	**COUNTRY:**	USA
Facility County:	BAYFIELD		
Facility State:	WI		
Facility ZIP Code:	54880		
Permit Issued By:	WISCONSIN DEPT OF NATURAL RESOURCES; AIR MGMT. PROGRAM (Agency Name) MS. KRISTIN HART(Agency Contact) (608)266-6876 kristin.hart@wisconsin.gov		
Other Agency Contact Info:	DON C. FAITH III, (608) 267-3135		
Permit Notes:			

Process/Pollutant Information

PROCESS NAME: P50 (S50). PREHEATER EQUIPPED, ROTARY LIME KILN

Process Type: 90.019 (Lime/Limestone Handling/Kilns/Storage/Manufacturing)

Primary Fuel: COAL

Throughput: 54.00 T/H STONE

Process Notes: KILN LIMITED TO 2% S COAL OR COAL / PET COKE BLEND. NATURAL GAS USED FOR STARTUP. KILN STACK EQUIPPED WITH CEMS FOR NOX, SO2, CO (AND OPACITY). FABRIC FILTER (MEMBRANE TYPE) HIGH TEMPERATURE BAGHOUSE. KILN CAPACITY IDENTIFIED AND PERMITTED AT 54 TONS PER HOUR OF STONE (LIMESTONE) FEED. SOME OF THE STONE USED HAS A HIGHER ORGANIC (CARBON) CONTENT, AND SEPARATE LIMITS ESTABLISHED FOR USE OF THIS TYPE OF LIMESTONE.

POLLUTANT NAME:	Particulate matter, fugitive
CAS Number:	PM
Test Method:	Unspecified
Pollutant Group(s):	
Emission Limit 1:	0.4600 LB/T HIGH ORGANIC CARBON STONE
Emission Limit 2:	0.1500 LB/T LOW ORGANIC CARBON STONE
Standard Emission:	0.1000 LB/T FRONT HALF ONLY (MACT/ BACT)

Did factors, other then air pollution technology considerations influence the BACT decisions: Y

Case-by-Case Basis:	BACT-PSD
Other Applicable Requirements:	MACT , SIP , NSPS
Control Method:	(A) FABRIC FILTER BAGHOUSE
Est. % Efficiency:	

Cost Effectiveness: 0 $/ton

Incremental Cost Effectiveness: 0 $/ton

Compliance Verified: Unknown

Pollutant/Compliance Notes: TOTAL PM (AND PM10) INCLUDES BACK HALF, EXCEPT WHERE SPECIFICALLY EXCLUDED. HIGH ORGANIC CARBON STONE HAD ORGANIC CONTENT OF 0.05% OR MORE. FABRIC FILTER BAGHOUSE REQUIRED TO ACHIEVE 0.010 GR/DSCF (FRONT HALF (FILTERABLE, NON-CONDENSIBLE) ONLY).

POLLUTANT NAME: Sulfur Dioxide (SO2)

CAS Number: 7446-09-5

Test Method: Unspecified

Pollutant Group(s): (InOrganic Compounds , Oxides of Sulfur (SOx))

Emission Limit 1: 0.6200 LB/T 24 HOUR AVERAGE

Emission Limit 2: 2.0000 PERCENT S FUEL SULFUR LIMIT

Standard Emission: 33.7000 LB/H 3 HOUR AVERAGE

Did factors, other then air pollution technology considerations influence the BACT decisions: Unknown

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (P) FUEL SULFUR LIMIT, INHERENT PROCESS COLLECTION OF SULFUR OXIDES.

Est. % Efficiency: 92.000

Cost Effectiveness: 0 $/ton

Incremental Cost Effectiveness: 0 $/ton

Compliance Verified: Unknown

Pollutant/Compliance Notes: 54 T/H STONE FEED RATE (24 HOUR AVERAGE). 2% FUEL SULFUR CONTENT LIMIT. PROCESS (PREHEATER KILN WITH BAGHOUSE) IS REQUIRED TO ACHIEVE AT LEAST 92% COLLECTION OF FUEL SULFUR. LIMIT ESTABLISHED IN PRIOR PERMIT (05-DCF-412).

POLLUTANT NAME: Nitrogen Oxides (NOx)

CAS Number: 10102

Test Method: Unspecified

Pollutant Group(s): (InOrganic Compounds , Oxides of Nitrogen (NOx) , Particulate Matter (PM))

Emission Limit 1: 1.8300 LB/T 24 HOUR AVG.

Emission Limit 2: 0.7000 LB/MMBTU MONTHLY AVG.

Standard Emission: 98.8000 LB/H 3 HOUR AVG.

Did factors, other then air pollution technology considerations influence the BACT decisions: Unknown

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (P) GOOD COMBUSTION CONTROL, OPTIMIZATION

Est. % Efficiency:

Cost Effectiveness: 0 $/ton

Incremental Cost Effectiveness: 0 $/ton

Compliance Verified: Unknown

Pollutant/Compliance Notes: NOX CEM. OPTIMIZATION IS THE USE OF TUNING AND ANALYSIS TO MINIMIZE NOX (IN ADDITION TO MEETING ALL OF THE BACT LIMITS, INCLUDING CO AND VOC LIMITS). LIMIT ESTABLISHED IN PRIOR PERMIT (05-DCF-412).

POLLUTANT NAME: Volatile Organic Compounds (VOC)

CAS Number: VOC

Test Method: Unspecified

Pollutant Group(s): (Volatile Organic Compounds (VOC))

Emission Limit 1: 33.0000 LB/H USING HIGH ORGANIC CONTENT LIMESTONE

Emission Limit 2: 5.4000 LB/H USING LOW ORGANIC CONTENT LIMESTONE

Standard Emission:

Did factors, other then air pollution technology considerations influence the BACT decisions: Y

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements: SIP

Control Method: (P) USE OF A PREHEATER KILN AND GOOD OPERATING PRACTICES: GOOD COMBUSTION CONTROL

Est. % Efficiency:

Cost Effectiveness: 0 $/ton

Incremental Cost Effectiveness: 0 $/ton

Compliance Verified: Unknown

Pollutant/Compliance Notes: HIGH ORGANIC CONTENT LIMESTONE CONTAINS 0.05% OR MORE ORGANIC CARBON. VOC LIMIT IS CITED " AS PROPANE." THE 33 LBS/HR VOC LIMIT IS PROVISIONAL, AND MAY BE INCREASED TO 38.6 LBS/HR.

POLLUTANT NAME: Carbon Monoxide

CAS Number: 630-08-0

Test Method: Unspecified

Pollutant Group(s): (InOrganic Compounds)

Emission Limit 1: 1.5600 LB/T 24 HR AVG., FIRING LOW ORGANIC STONE

Emission Limit 2: 71.2000 T/ MO. 12 MO. AVG.

Standard Emission: 310.0000 LB/H 3 HR AVG., FIRING HIGH ORGANIC STONE

Did factors, other then air pollution technology considerations influence the BACT decisions: Y

Case-by-Case Basis: BACT-PSD

Other Applicable Requirements:

Control Method: (P) PREHEATER KILN, GOOD OPERATING PRACTICES (GOOD COMBUSTION CONTROL)

Est. % Efficiency:

Cost Effectiveness: 0 $/ton

Incremental Cost Effectiveness: 0 $/ton

Compliance Verified: Unknown

Pollutant/Compliance Notes:	HIGH ORGANIC CONTENT STONE IS A LIMESTONE CONTAINING 0.05 WT% ORGANIC CARBON CONTENT OR HIGHER. 54 TON PER HOUR LIMESTONE BASIS / LIMITATION (24 HR. AVG.)

POLLUTANT NAME:	Sulfuric Acid (mist, vapors, etc)
CAS Number:	7664-93-9
Test Method:	Unspecified
Pollutant Group(s):	(InOrganic Compounds , Particulate Matter (PM))
Emission Limit 1:	1.5000 LB/H
Emission Limit 2:	
Standard Emission:	

Did factors, other then air pollution technology considerations influence the BACT decisions: Unknown

Case-by-Case Basis:	N/A
Other Applicable Requirements:	
Control Method:	(P) FUEL SULFUR LIMIT (2%) AND INHERENT COLLECTION FROM PREHEATER / FABRIC FILTER (92% OF S COMPOUNDS).
Est. % Efficiency:	
Cost Effectiveness:	0 $/ton
Incremental Cost Effectiveness:	0 $/ton
Compliance Verified:	Unknown
Pollutant/Compliance Notes:	

POLLUTANT NAME:	Hazardous Air Pollutants (HAP)
CAS Number:	HAP
Test Method:	Unspecified
Pollutant Group(s):	(Hazardous Air Pollutants (HAP))
Emission Limit 1:	2.8500 LB/H BENZENE
Emission Limit 2:	4.9000 LB/H VINYL CHLORIDE
Standard Emission:	2.0000 LB/H FORMALDEHYDE

Did factors, other then air pollution technology considerations influence the BACT decisions: Unknown

Case-by-Case Basis:	N/A
Other Applicable Requirements:	OTHER
Control Method:	(P) USE OF PREHEATER KILN USING GOOD OPERATING PRACTICES (GOOD COMBUSTION PRACTICES)
Est. % Efficiency:	
Cost Effectiveness:	0 $/ton
Incremental Cost Effectiveness:	0 $/ton
Compliance Verified:	Unknown
Pollutant/Compliance Notes:	LIMITS BASED ON STATE (ONLY) HAZARDOUS AIR RULE. USE OF HIGH ORGANIC CARBON LIMESTONE (0.05 WT. % ORGANIC CARBON) WAS FOUND TO RESULT IN CONSIDERABLE PRODUCTS OF INCOMPLETE COMBUSTION WHEN PREHEATER KILN WAS OPERATED AT THE PERMITTED CAPACITY.

APPENDIX B : SO_2 CONTROL COST CALCULATIONS

REGIONAL HAZE 2ND PLANNING PERIOD - FOUR FACTOR ANALYSIS

Table 1. Economic Analysis - 100% Natural Gas at Kilns 2 and 4

Parameter	Kiln 2	Kiln 4	Kilns 2 and 4 Combined	Notes
Capital Costs ($)				
Cost of Upgrading Gas Train to NFPA Standard	$ 700,000	$ 700,000	$ 1,400,000	Based on information provided by the plant as well as constructions at Apex's Kilns 1 and 3.
Cost of Burner Upgrade and Fuel Piping Modification	$ 450,000	$ 450,000	$ 900,000	
Capital Recovery Factor	0.079	0.079	0.079	Based on an interest rate of 4.75% (the approximate average bank prime interest rate for the last 3 years)
Annualized Capital Costs ($/yr)	$ 90,333	$ 90,333	$ 180,666	
Annual Costs ($/yr)				
Annual Fuel Cost Increase ($/yr)	$ 68,565	$ 1,499,821	$ 1,568,386	Per fuel cost evaluations provided in Table 2
Production Loss ($/yr)	$ 8,640,000	$ 90,000	$ 8,730,000	Based on 10% loss in production
Total Annual Cost ($/yr)	$ 8,708,565	$ 1,589,821	$ 10,298,386	
Annual Emissions Reductions (ton/yr)				
Baseline SO_2 Emissions	3.42	14.30	17.72	Based on 2016 - 2018 baseline actual fuel analysis.
Baseline NOx Emissions	19.11	686.68	705.80	
Baseline PM_{10} Emissions	1.13	23.48	24.61	
Baseline Visibility Impairing Pollutants	23.66	724.46	748.13	
100% Natural Gas SO_2 Emissions	0.0027	0.005	0.008	Based on evaluation of SO2 emissions burning 100% natural gas.
100% Natural Gas NOx Emissions	21.52	848.89	870.41	
100% Natural Gas PM_{10} Emissions	1.1267	23.48	24.61	
100% Natural Gas Visibility Impairing Pollutants	22.65	872.38	895.03	
Visibility Impairing Pollutants Reduced (tons/year)	1.02	-147.92	-146.90	The direct and precursor pollutants that can impair visibility include SO2, NOx, and PM (https://www.epa.gov/sites/production/files/2019-08/documents/8-20-2019_-regional_haze_guidance_final_guidance.pdf)
Cost Effectiveness ($/ton)	**$ 8,666,204**	-	-	

Table 2a. Cost of SO_2 Reductions from Alternative Fuel Scenarios - Kiln 2

Fuel Scenario	Fuel	Annual Consumption [1]	Consumption Units	Fuel Cost [2] ($/unit)	Annual Fuel Cost	Annual Fuel Cost Increase
Base	Coal	93,924	MMBtu	[redacted]		
	Coke	0	MMBtu			
	Natural Gas	2,125	MMBtu			
	Total					
All Natural Gas	Natural Gas	96,049	MMBtu			

[1] Annual fuel consumption based on average fuel consumption during the 2016-2018 baseline years.

[2] Cost of Coal, Coke and Natural gas as listed in the Apex Fuel Budget 2020 provided by Lhoist on December 11, 2019.

Table 2b. Cost of SO_2 Reductions from Alternative Fuel Scenarios - Kiln 4

Fuel Scenario	Fuel	Annual Consumption [1]	Consumption Units	Fuel Cost [2] ($/unit)	Annual Fuel Cost	Annual Fuel Cost Increase
Base	Coal	1,742,129	MMBtu	[redacted]		
	Coke	198,319	MMBtu			
	Natural Gas	9,351	MMBtu			
	Total					
All Natural Gas	Natural Gas	1,949,799	MMBtu			

[1] Annual fuel consumption based on average fuel consumption during the 2016-2018 baseline years.

[2] Cost of Coal, Coke and Natural gas as listed in the Apex Fuel Budget 2020 provided by Lhoist on December 11, 2019.

Alternative Fuel Scenarios

Current Scenario - Kiln 1
Kiln 1 Throughput Limit - 109,500 tons/year

Kiln 1 Baseline Lime Production	**96,757**	**tons**
Kiln 1 Baseline SO_2 Emissions	**107.3**	**tpy**
Kiln 1 Baseline NOx Emissions	**303.5**	**tpy**

Table 3a. Baseline Emissions - Kiln 1

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2, 3] Btu/yr	Percent Fuel Blend	NOx Emission Factor - Value	NOx Emission Factor - Units	Baseline Sulfur Emissions [6] ton/yr	Baseline Pre-Scrub SO_2 Emissions [7] ton/yr	Baseline Post-Scrub SO_2 Emissions [8] ton/yr	Baseline PM_{10} Emissions[9] ton/yr	Baseline Fuel-Based NO_x Emissions [10, 11] ton/yr	NOx Emissions Scaled to Baseline[12] ton/yr
Coal	0	ton/yr	0.00E+00	0%	3.10	lb/ton lime [4]	0.00	0.00	0.00	18.56	0.00	0.00
Coke	12,507	ton/yr	3.44E+11	60%	0.09	lb/MMBtu coke [5]	689.12	1,378.24	137.82		16.32	58.84
Natural Gas	230,012	MMBtu/yr	2.30E+11	40%	3.50	lb/ton lime [4]	3.22E-02	6.44E-02	6.44E-03		67.86	244.67
Total			**5.74E+11**	**100%**			**689.15**	**1,378.31**	**137.83**	**18.56**	**84.18**	**303.52**

[1] Historical consumption averaged over baseline period 2016 to 2018 as provided by Lhoist on December 11, 2019.
[2] Annual fuel heat input (coal, coke) (Btu/yr) = annual consumption (tons/yr) x heat content (Btu/lb) x 2,000 (lb/ton)
[3] Annual fuel heat usage, natural gas (Btu/yr) = annual consumption (MMBtu/yr) / 1,000,000 (Btu/MMBtu)
[4] Per AP-42 Section 11.17
[5] Per EPA Webfire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln
[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)
[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol
[8] SO_2 emissions = potential SO_2 emissions x (1 - 90 % inherent scrubbing efficiency)
[9] PM_{10} baseline emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.
[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input
[11] Fuel-based NOx emissions for coal and natural gas = NOx emission factor x throughput x ratio of fuel input to total heat input
[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent. For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.
The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:
NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 3b. Emission Limits from Clark County Title V Permit - Kiln 1 [1]

NOx (tpy)	SO_2 (tpy)
343.49	413.09

[1] Per Table III-A-3

Table 3c. Fuel Blend Generating Lowest SO_2 Emissions - HiCal - Kiln 1

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2, 3] Btu/yr	Percent Fuel Blend	NOx Emission Factor - Value	NOx Emission Factor - Units	Baseline Sulfur Emissions [6] ton/yr	Baseline Pre-Scrub SO_2 Emissions [7] ton/yr	Baseline Post-Scrub SO_2 Emissions [8] ton/yr	Baseline PM_{10} Emissions[9] ton/yr	Fuel-Based NO_x Emissions [10, 11] ton/yr	NOx Emissions Scaled to Baseline[12] ton/yr
Coal	18,675	tons/yr	4.30E+11	75%	3.10	lb/ton lime [4]	78.44	156.87	15.69	18.56	112.48	405.57
Coke	5,218	tons/yr	1.43E+11	25%	0.09	lb/MMBtu coke [5]	287.50	574.99	57.50		6.81	24.55
Total			**5.74E+11**	**100%**			**365.93**	**731.86**	**73.19**	**18.56**	**119.29**	**430.12**

[1] Annual consumption (tons/yr) = Annual Heat Input (Btu/yr) / Fuel Heating Value (Btu/lb) / 2,000 (lb/ton)

[2] Annual fuel heat input (Btu/yr) = total baseline heat input (MMBtu/yr) x Required Fuel Blend (%)

[3] HiCal Fuel Blend must fall within 65%-75% Coal and 25%-35% Coke per Lhoist internal production analysis. Fuel Blend ranges provided on June 10, 2020.

[4] Per AP-42 Section 11.17

[5] Per EPA Webfire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln

[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)

[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol

[8] SO_2 emissions = potential SO_2 emissions x (1 - 90% inherent scrubbing efficiency)

[9] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.

[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input

[11] Fuel-based NOx emissions for coal = NOx emission factor x throughput x ratio of fuel input to total heat input

[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent. For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.

The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:

NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 3d. Fuel Blend Generating Highest SO_2 Emissions - HiCal - Kiln 1

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2] Btu/yr	Percent Fuel Blend [3]	NOx Emission Factor - Value	NOx Emission Factor - Units	Sulfur Emissions [6] ton/yr	Pre-Scrub SO_2 Emissions [7] ton/yr	Post-Scrub SO_2 Emissions [8] ton/yr	Baseline PM_{10} Emissions[9] ton/yr	Fuel-Based NO_x Emissions [10, 11] ton/yr	NOx Emissions Scaled to Baseline[12] ton/yr
Coal	16,185	tons/yr	3.73E+11	65%	3.10	lb/ton lime [4]	67.98	135.95	13.60	18.56	97.48	351.49
Coke	7,305	tons/yr	2.01E+11	35%	0.09	lb/MMBtu coke [5]	402.49	804.99	80.50		9.53	34.37
Total			**5.74E+11**	**100%**			**470.47**	**940.94**	**94.09**	**18.56**	**107.01**	**385.86**

[1] Annual consumption (tons/yr) = Annual Heat Input (Btu/yr) / Fuel Heating Value (Btu/lb) / 2,000 (lb/ton)

[2] Annual fuel heat input (Btu/yr) = total baseline heat input (MMBtu/yr) x Required Fuel Blend (%)

[3] HiCal Fuel Blend must fall within 65%-75% Coal and 25%-35% Coke per Lhoist internal production analysis. Fuel Blend ranges provided on June 10, 2020.

[4] Per AP-42 Section 11.17

[5] Per EPA Webfire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln

[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)

[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol

[8] SO_2 emissions = potential SO_2 emissions x (1 - 90% inherent scrubbing efficiency)

[9] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.

[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input

[11] Fuel-based NOx emissions for coal = NOx emission factor x throughput x ratio of fuel input to total heat input

[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent. For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.

The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:

NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 3e. Fuel Blend Generating Lowest SO_2 Emissions - Dolo - Kiln 1

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2] Btu/yr	Percent Fuel Blend [3]	NOx Emission Factor - Value	NOx Emission Factor - Units	Sulfur Emissions [6] ton/yr	Pre-Scrub SO_2 Emissions [7] ton/yr	Post-Scrub SO_2 Emissions [8] ton/yr	Baseline PM_{10} Emissions[9] ton/yr	Fuel-Based NO_x Emissions [10, 11] ton/yr	NOx Emissions Scaled to Baseline[12] ton/yr
Coal	0	tons/yr	0.00E+00	0%	3.10	lb/ton lime [4]	0.00	0.00	0.00		0.00	0.00
Coke	10,435	tons/yr	2.87E+11	50%	0.09	lb/MMBtu coke [5]	574.99	1,149.98	115.00	18.56	13.62	49.10
Natural Gas	286,975	MMBtu/yr	2.87E+11	50%	3.50	lb/ton lime [4]	4.02E-02	8.04E-02	8.04E-03		84.66	305.27
Total			**5.74E+11**	**100%**			**575.03**	**1,150.06**	**115.01**	**18.56**	**98.28**	**354.36**

[1] Annual consumption (tons/yr) = Annual Heat Input (Btu/yr) / Fuel Heating Value (Btu/lb) / 2,000 (lb/ton)

[2] Annual fuel heat input (Btu/yr) = total baseline heat input (MMBtu/yr) x Required Fuel Blend (%)

[3] Dolo Fuel Blend must fall within 50%-80% Coke and 20%-50% Natural Gas per Lhoist internal production analysis. Fuel Blend ranges provided on June 10, 2020.

[4] Per AP-42 Section 11.17

[5] Per EPA WebFire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln

[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)

[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol

[8] SO_2 emissions = potential SO_2 emissions x (1 - 90% inherent scrubbing efficiency)

[9] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.

[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input

[11] Fuel-based NOx emissions for coal and natural gas = NOx emission factor x throughput x ratio of fuel input to total heat input

[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent. For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.

The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:

NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 3f. Fuel Blend Generating Highest SO_2 Emissions - Dolo - Kiln 1

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2] Btu/yr	Percent Fuel Blend [3]	NOx Emission Factor - Value	NOx Emission Factor - Units	Sulfur Emissions [6] ton/yr	Pre-Scrub SO_2 Emissions [7] ton/yr	Post-Scrub SO_2 Emissions [8] ton/yr	Baseline PM_{10} Emissions[9] ton/yr	Fuel-Based NO_x Emissions [10, 11] ton/yr	NOx Emissions Scaled to Baseline[12] ton/yr
Coal	0	tons/yr	0.00E+00	0%	3.10	lb/ton lime [4]	0.00	0.00	0.00		0.00	0.00
Coke	16,697	tons/yr	4.59E+11	80%	0.09	lb/MMBtu coke [5]	919.98	1,839.97	184.00	18.56	21.79	78.56
Natural Gas	114,790	MMBtu/yr	1.15E+11	20%	3.50	lb/ton lime [4]	1.61E-02	3.22E-02	3.22E-03		33.86	122.11
Total			**5.74E+11**	**100%**			**920.00**	**1,840.00**	**184.00**	**18.56**	**55.65**	**200.66**

[1] Annual consumption (tons/yr) = Annual Heat Input (Btu/yr) / Fuel Heating Value (Btu/lb) / 2,000 (lb/ton)

[2] Annual fuel heat input (Btu/yr) = total baseline heat input (MMBtu/yr) x Required Fuel Blend (%)

[3] Dolo Fuel Blend must fall within 50%-80% Coke and 20%-50% Natural Gas per Lhoist internal production analysis. Fuel Blend ranges provided on June 10, 2020.

[4] Per AP-42 Section 11.17

[5] Per EPA WebFire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln

[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)

[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol

[8] SO_2 emissions = potential SO_2 emissions x (1 - 90% inherent scrubbing efficiency)

[9] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.

[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input

[11] Fuel-based NOx emissions for coal and natural gas = NOx emission factor x throughput x ratio of fuel input to total heat input

[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent. For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.

The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:

NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 3g. Summary of Emissions - Kiln 1

Product	Fuel Blend Generating	SO_2 Emissions		NOx Emissions	
		Total (ton/yr)	Reduction (+ve) vs Increase (-ve) (%)	Total (ton/yr)	Reduction (+ve) vs Increase (-ve) (%)
Baseline	-	**138**	-	**304**	-
HiCal	Lowest SO_2	73	47%	430	-42%
HiCal	Highest SO_2	94	32%	386	-27%
Dolo	Lowest SO_2	115	17%	354	-17%
Dolo	Highest SO_2	184	-33%	201	34%

Alternative Fuel Scenarios

Current Scenario - Kiln 2
Kiln 2 Throughput Limit - 109,500 tons/year

Kiln 2 Baseline Lime Production	**5,982**	**tons**
Kiln 2 Baseline SO_2 Emissions	**5.32**	**tpy**
Kiln 2 Baseline NOx Emissions	**19.1**	**tpy**

Table 4a. Baseline Emissions - Kiln 2

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2, 3] Btu/yr	Percent Fuel Blend	NOx Emission Factor - Value	NOx Emission Factor - Units	Baseline Sulfur Emissions [6] ton/yr	Baseline Pre-Scrub SO_2 Emissions [7] ton/yr	Baseline Post-Scrub SO_2 Emissions [8] ton/yr	Baseline PM_{10} Emissions [9] ton/yr	Baseline Fuel-Based NO_x Emissions [10, 11] ton/yr	NOx Emissions Scaled to Baseline [12] ton/yr
Coal	4,075	ton/yr	9.39E+10	98%	3.10	lb/ton lime [4]	17.11	34.23	3.42	1.13	9.07	18.64
Coke	0	ton/yr	0.00E+00	0%	0.09	lb/MMBtu coke [5]	0.00	0.00	0.00		0.00	0.00
Natural Gas	2,125	MMBtu/yr	2.13E+09	2%	3.50	lb/ton lime [4]	2.98E-04	5.95E-04	5.95E-05		0.23	0.48
Total			**9.60E+10**	**100%**			**17.11**	**34.23**	**3.42**	**1.13**	**9.30**	**19.11**

[1] Historical consumption averaged over baseline period 2016 to 2018 as provided by Lhoist on December 11, 2019.
[2] Annual fuel heat input (coal, coke) (Btu/yr) = annual consumption (tons/yr) x heat content (Btu/lb) x 2,000 (lb/ton)
[3] Annual fuel heat usage, natural gas (Btu/yr) = annual consumption (MMBtu/yr) / 1,000,000 (Btu/MMBtu)
[4] Per AP-42 Section 11.17
[5] Per EPA WebFire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln
[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)
[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol
[8] SO_2 emissions = potential SO_2 emissions x (1 - 90% inherent scrubbing efficiency)
[9] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.
[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input
[11] Fuel-based NOx emissions for coal and natural gas = NOx emission factor x throughput x ratio of fuel input to total heat input
[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent. For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.
The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:
NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 4b. Emission Limits from Clark County Title V Permit - Kiln 2 [1]

NOx (tpy)	SO_2 (tpy)
349.85	271.56

[1] Per Table III-A-3

Table 4c. Fuel Blend Generating Lowest SO_2 Emissions - HiCal - Kiln 2

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2] Btu/yr	Percent Fuel Blend [3]	NOx Emission Factor - Value	NOx Emission Factor - Units	Sulfur Emissions [6] ton/yr	Pre-Scrub SO_2 Emissions [7] ton/yr	Post-Scrub SO_2 Emissions [8] ton/yr	Baseline PM_{10} Emissions[9] ton/yr	Fuel-Based NO_x Emissions [10, 11] ton/yr	NOx Emissions Scaled to Baseline[12] ton/yr
Coal	3,125	tons/yr	7.20E+10	75%	3.10	lb/ton lime [4]	13.13	26.25	2.63	1.13	6.95	14.29
Coke	873	tons/yr	2.40E+10	25%	0.09	lb/MMBtu coke [5]	48.11	96.22	9.62		1.14	2.34
Total			**9.60E+10**	**100%**			**61.24**	**122.48**	**12.25**	**1.13**	**8.09**	**16.64**

[1] Annual consumption (tons/yr) = Annual Heat Input (Btu/yr) / Fuel Heating Value (Btu/lb) / 2,000 (lb/ton)
[2] Annual fuel heat input (Btu/yr) = total baseline heat input (MMBtu/yr) x Required Fuel Blend (%)
[3] HiCal Fuel Blend must fall within 65%-75% Coal and 25%-35% Coke per Lhoist internal production analysis. Fuel Blend ranges provided on June 10, 2020.
[4] Per AP-42 Section 11.17
[5] Per EPA Webfire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln
[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)
[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol
[8] SO_2 emissions = potential SO_2 emissions x (1 - 90% inherent scrubbing efficiency)
[9] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.
[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input
[11] Fuel-based NOx emissions for coal = NOx emission factor x throughput x ratio of fuel input to total heat input
[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent. For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.
The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:
NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 4d. Fuel Blend Generating Highest SO_2 Emissions - HiCal - Kiln 2

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2] Btu/yr	Percent Fuel Blend [3]	NOx Emission Factor - Value	NOx Emission Factor - Units	Sulfur Emissions [6] ton/yr	Pre-Scrub SO_2 Emissions [7] ton/yr	Post-Scrub SO_2 Emissions [8] ton/yr	Baseline PM_{10} Emissions[9] ton/yr	Fuel-Based NO_x Emissions [10, 11] ton/yr	NOx Emissions Scaled to Baseline[12] ton/yr
Coal	2,709	tons/yr	6.24E+10	65%	3.10	lb/ton lime [4]	11.38	22.75	2.28	1.13	6.03	12.39
Coke	1,222	tons/yr	3.36E+10	35%	0.09	lb/MMBtu coke [5]	67.36	134.71	13.47		1.60	3.28
Total			**9.60E+10**	**100%**			**78.73**	**157.46**	**15.75**	**1.13**	**7.62**	**15.67**

[1] Annual consumption (tons/yr) = Annual Heat Input (Btu/yr) / Fuel Heating Value (Btu/lb) / 2,000 (lb/ton)
[2] Annual fuel heat input (Btu/yr) = total baseline heat input (MMBtu/yr) x Required Fuel Blend (%)
[3] HiCal Fuel Blend must fall within 65%-75% Coal and 25%-35% Coke per Lhoist internal production analysis. Fuel Blend ranges provided on June 10, 2020.
[4] Per AP-42 Section 11.17
[5] Per EPA Webfire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln
[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)
[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol
[8] SO_2 emissions = potential SO_2 emissions x (1 - 90% inherent scrubbing efficiency)
[9] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.
[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input
[11] Fuel-based NOx emissions for coal = NOx emission factor x throughput x ratio of fuel input to total heat input
[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent. For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.
The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:
NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 4e. 100% Natural Gas Combustion Emissions - Kiln 2

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2] Btu/yr	Percent Fuel Blend	NOx Emission Factor - Value	NOx Emission Factor - Units	Sulfur Emissions [4] ton/yr	Pre-Scrub SO_2 Emissions [5] ton/yr	Post-Scrub SO_2 Emissions [6] ton/yr	PM_{10} Emissions [7] ton/yr	Fuel-Based NO_x Emissions [8] ton/yr	NOx Emissions Scaled to Baseline [9] ton/yr
Natural Gas	96,049	MMBtu/yr	9.60E+10	100%	3.50	lb/ton lime [3]	0.013	0.027	2.69E-03	1.13	10.47	21.52

[1] Annual consumption of natural gas (MMBtu/yr) = total annual heat input, current scenario (Btu/yr) / 1,000,000 (Btu/MMBtu)

[2] Annual heat input, natural gas (Btu/yr) = total heat input, current scenario (Btu/yr)

[3] Per AP-42 Section 11.17

[4] Potential sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)

[5] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol

[6] SO_2 emissions = potential SO_2 emissions x (1 - 90% inherent scrubbing efficiency)

[7] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.

[8] Fuel-based NOx emissions for natural gas = NOx emission factor x throughput x ratio of fuel input to total heat input

[9] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent. For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.

The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:

NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 4f. Summary of Emissions - Kiln 2

Product	Fuel Blend Generating	SO_2 Emissions		NOx Emissions	
		Total (ton/yr)	Reduction (+ve) vs Increase (-ve) (%)	Total (ton/yr)	Reduction (+ve) vs Increase (-ve) (%)
Baseline	-	3	-	19	-
HiCal	Lowest SO_2	12	-258%	17	13%
HiCal	Highest SO_2	16	-360%	16	18%
HiCal	NG Only	0	100%	22	-13%

Alternative Fuel Scenarios

Current Scenario - Kiln 3

Kiln 3 Throughput Limit - 146,000 tons/year		
Kiln 3 Baseline Lime Production	**47,083**	**tons**
Kiln 3 Baseline SO_2 Emissions	**14.62**	**tpy**
Kiln 3 Baseline NOx Emissions	**154.2**	**tpy**

Table 5a. Baseline Emissions - Kiln 3

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2, 3]	Percent Fuel Blend	NOx Emission Factor - Value	NOx Emission Factor - Units	Baseline Sulfur Emissions [6]	Baseline Pre-Scrub SO_2 Emissions [7]	Baseline Post-Scrub SO_2 Emissions [8]	Baseline PM_{10} Emissions [9]	Baseline Fuel-Based NO_x Emissions [10, 11]	NOx Emissions Scaled to Baseline [12]
			Btu/yr				ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr
Coal	14,241	ton/yr	3.28E+11	95%	3.10	lb/ton lime [4]	59.81	119.62	11.96	15.86	69.46	150.76
Coke	452	ton/yr	1.24E+10	4%	0.09	lb/MMBtu coke [5]	24.93	49.86	4.99		0.59	1.28
Natural Gas	4,161	MMBtu/yr	4.16E+09	1%	3.50	lb/ton lime [4]	5.83E-04	1.17E-03	1.17E-04		0.99	2.16
Total			**3.45E+11**	**100%**			**84.74**	**169.48**	**16.95**	**15.86**	**71.05**	**154.20**

[1] Historical consumption averaged over baseline period 2016 to 2018 as provided by Lhoist on December 11, 2019.
[2] Annual fuel heat input (coal, coke) (Btu/yr) = annual consumption (tons/yr) x heat content (Btu/lb) x 2,000 (lb/ton)
[3] Annual fuel heat usage, natural gas (Btu/yr) = annual consumption (MMBtu/yr) / 1,000,000 (Btu/MMBtu)
[4] Per AP-42 Section 11.17
[5] Per EPA Webfire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln
[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)
[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol
[8] SO_2 emissions = potential SO_2 emissions x (1 - 90% inherent scrubbing efficiency)
[9] PM_{10} baseline emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.
[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input
[11] Fuel-based NOx emissions for coal and natural gas = NOx emission factor x throughput x ratio of fuel input to total heat input
[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent.
For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.
The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:
NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 5b. Emission Limits from Clark County Title V Permit - Kiln 3 [1]

NOx (tpy)	SO_2 (tpy)
478.15	419.75

[1] Per Table III-A-3

Table 5c. Fuel Blend Generating Lowest SO_2 Emission - HiCal - Kiln 3

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2, 3]	Percent Fuel Blend	NOx Emission Factor - Value	NOx Emission Factor - Units	Baseline Sulfur Emissions [6]	Baseline Pre-Scrub SO_2 Emissions [7]	Baseline Post-Scrub SO_2 Emissions [8]	Baseline PM_{10} Emissions [9]	Fuel-Based NO_x Emissions [10, 11]	NOx Emissions Scaled to Baseline [12]
			Btu/yr				ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr
Coal	11,221	tons/yr	2.59E+11	75%	3.10	lb/ton lime [4]	47.13	94.25	9.43	15.86	54.73	118.79
Coke	3,135	tons/yr	8.62E+10	25%	0.09	lb/MMBtu coke [5]	172.74	345.47	34.55		4.09	8.88
Total			**3.45E+11**	**100%**			**219.86**	**439.73**	**43.97**	**15.86**	**58.82**	**127.67**

[1] Annual consumption (tons/yr) = Annual Heat Input (Btu/yr) / Fuel Heating Value (Btu/lb) / 2,000 (lb/ton)
[2] Annual fuel heat input (Btu/yr) = total baseline heat input (MMBtu/yr) x Required Fuel Blend (%)
[3] HiCal Fuel Blend must fall within 65%-75% Coal and 25%-35% Coke per Lhoist internal production analysis. Fuel Blend ranges provided on June 10, 2020.
[4] Per AP-42 Section 11.17
[5] Per EPA WebFire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln
[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)
[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol
[8] SO_2 emissions = potential SO_2 emissions x (1 - 90% inherent scrubbing efficiency)
[9] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.
[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input
[11] Fuel-based NOx emissions for coal = NOx emission factor x throughput x ratio of fuel input to total heat input
[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent. For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.
The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:
NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 5d. Fuel Blend Generating Highest SO_2 Emissions - HiCal - Kiln 3

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2]	Percent Fuel Blend [3]	NOx Emission Factor - Value	NOx Emission Factor - Units	Sulfur Emissions [6]	Pre-Scrub SO_2 Emissions [7]	Post-Scrub SO_2 Emissions [8]	Baseline PM_{10} Emissions [9]	Fuel-Based NO_x Emissions [10, 11]	NOx Emissions Scaled to Baseline [12]
			Btu/yr				ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr
Coal	9,725	tons/yr	2.24E+11	65%	3.10	lb/ton lime [4]	40.84	81.69	8.17	15.86	47.44	102.95
Coke	4,389	tons/yr	1.21E+11	35%	0.09	lb/MMBtu coke [5]	241.83	483.66	48.37		5.73	12.43
Total			**3.45E+11**	**100%**			**282.67**	**565.35**	**56.53**	**15.86**	**53.16**	**115.38**

[1] Annual consumption (tons/yr) = Annual Heat Input (Btu/yr) / Fuel Heating Value (Btu/lb) / 2,000 (lb/ton)
[2] Annual fuel heat input (Btu/yr) = total baseline heat input (MMBtu/yr) x Required Fuel Blend (%)
[3] HiCal Fuel Blend must fall within 65%-75% Coal and 25%-35% Coke per Lhoist internal production analysis. Fuel Blend ranges provided on June 10, 2020.
[4] Per AP-42 Section 11.17
[5] Per EPA WebFire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln
[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)
[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol
[8] SO_2 emissions = potential SO_2 emissions x (1 - 90% inherent scrubbing efficiency)
[9] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.
[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input
[11] Fuel-based NOx emissions for coal = NOx emission factor x throughput x ratio of fuel input to total heat input
[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent. For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.
The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:
NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 5e. Fuel Blend Generating Lowest SO_2 Emissions - Dolo - Kiln 3

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2]	Percent Fuel Blend [3]	NOx Emission Factor - Value	NOx Emission Factor - Units	Sulfur Emissions [6]	Pre-Scrub SO_2 Emissions [7]	Post-Scrub SO_2 Emissions [8]	Baseline PM_{10} Emissions [9]	Fuel-Based NO_x Emissions [10, 11]	NOx Emissions Scaled to Baseline [12]
			Btu/yr				ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr
Coal	0	tons/yr	0.00E+00	0%	3.10	lb/ton lime [4]	0.00	0.00	0.00		0.00	0.00
Coke	6,270	tons/yr	1.72E+11	50%	0.09	lb/MMBtu coke [5]	345.47	690.95	69.09	15.86	8.18	17.76
Natural Gas	172,424	MMBtu/yr	1.72E+11	50%	3.50	lb/ton lime [4]	2.41E-02	4.83E-02	4.83E-03		41.20	89.41
Total			**3.45E+11**	**100%**			**345.50**	**691.00**	**69.10**	**15.86**	**49.38**	**107.17**

[1] Annual consumption (tons/yr) = Annual Heat Input (Btu/yr) / Fuel Heating Value (Btu/lb) / 2,000 (lb/ton)
[2] Annual fuel heat input (Btu/yr) = total baseline heat input (MMBtu/yr) x Required Fuel Blend (%)
[3] Dolo Fuel Blend must fall within 50%-80% Coke and 20%-50% Natural Gas per Lhoist internal production analysis. Fuel Blend ranges provided on June 10, 2020.
[4] Per AP-42 Section 11.17
[5] Per EPA Webfire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln
[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)
[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol
[8] SO_2 emissions = potential SO_2 emissions x (1 - 90% inherent scrubbing efficiency)
[9] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.
[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input
[11] Fuel-based NOx emissions for coal and natural gas = NOx emission factor x throughput x ratio of fuel input to total heat input
[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent. For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.
The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:
NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 5f. Fuel Blend Generating Highest SO_2 Emissions - Dolo - Kiln 3

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2]	Percent Fuel Blend [3]	NOx Emission Factor - Value	NOx Emission Factor - Units	Sulfur Emissions [6]	Pre-Scrub SO_2 Emissions [7]	Post-Scrub SO_2 Emissions [8]	Baseline PM_{10} Emissions [9]	Fuel-Based NO_x Emissions [10, 11]	NOx Emissions Scaled to Baseline [12]
			Btu/yr				ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr
Coal	0	tons/yr	0.00E+00	0%	3.10	lb/ton lime [4]	0.00	0.00	0.00		0.00	0.00
Coke	10,032	tons/yr	2.76E+11	80%	0.09	lb/MMBtu coke [5]	552.76	1,105.52	110.55	15.86	13.09	28.41
Natural Gas	68,970	MMBtu/yr	6.90E+10	20%	3.50	lb/ton lime [4]	9.66E-03	1.93E-02	1.93E-03		16.48	35.76
Total			**3.45E+11**	**100%**			**552.77**	**1,105.54**	**110.55**	**15.86**	**29.57**	**64.17**

[1] Annual consumption (tons/yr) = Annual Heat Input (Btu/yr) / Fuel Heating Value (Btu/lb) / 2,000 (lb/ton)
[2] Annual fuel heat input (Btu/yr) = total baseline heat input (MMBtu/yr) x Required Fuel Blend (%)
[3] Dolo Fuel Blend must fall within 50%-80% Coke and 20%-50% Natural Gas per Lhoist internal production analysis. Fuel Blend ranges provided on June 10, 2020.
[4] Per AP-42 Section 11.17
[5] Per EPA Webfire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln
[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)
[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol
[8] SO_2 emissions = potential SO_2 emissions x (1 - 90% inherent scrubbing efficiency)
[9] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.
[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input
[11] Fuel-based NOx emissions for coal and natural gas = NOx emission factor x throughput x ratio of fuel input to total heat input
[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent. For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.
The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:
NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 5g. Summary of Emissions - Kiln 3

Product	Fuel Blend Generating	SO_2 Emissions		NOx Emissions	
		Total (ton/yr)	Reduction (+ve) vs Increase (-ve) (%)	Total (ton/yr)	Reduction (+ve) vs Increase (-ve) (%)
Baseline	-	17	-	154	-
HiCal	Lowest SO_2	44	-159%	128	17%
HiCal	Highest SO_2	57	-234%	115	25%
Dolo	Lowest SO_2	69	-308%	107	31%
Dolo	Highest SO_2	111	-552%	64	58%

Alternative Fuel Scenarios

Current Scenario - Kiln 4
Kiln 4 Throughput Limit - 475,000 tons/year

Kiln 4 Baseline Lime Production	**421,886**	**tons**
Kiln 4 Baseline SO_2 Emissions	**8.21**	**tpy**
Kiln 4 Baseline NOx Emissions	**686.7**	**tpy**

Table 6a. Baseline Emissions - Kiln 4

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2, 3]	Percent Fuel Blend	NOx Emission Factor - Value	NOx Emission Factor - Units	Baseline Sulfur Emissions [6]	Baseline Pre-Scrub SO_2 Emissions [7]	Baseline Post-Scrub SO_2 Emissions [8]	Baseline PM_{10} Emissions [9]	Baseline Fuel-Based NO_x Emissions [10, 11]	NOx Emissions Scaled to Baseline [12]
			Btu/yr				ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr
Coal	75,580	ton/yr	1.74E+12	89%	3.10	lb/ton lime [4]	317.44	634.87	6.35	23.48	584.27	671.79
Coke	7,212	ton/yr	1.98E+11	10%	0.09	lb/MMBtu coke [5]	397.36	794.72	7.95		9.41	10.82
Natural Gas	9,351	MMBtu/yr	9.35E+09	0%	3.50	lb/ton lime [4]	1.31E-03	2.62E-03	2.62E-05		3.54	4.07
Total			**1.95E+12**	**100%**			**714.80**	**1,429.59**	**14.30**	**23.48**	**597.23**	**686.68**

[1] Historical consumption averaged over baseline period 2016 to 2018 as provided by Lhoist on December 11, 2019.
[2] Annual fuel heat input (coal, coke) (Btu/yr) = annual consumption (tons/yr) x heat content (Btu/lb) x 2,000 (lb/ton)
[3] Annual fuel heat usage, natural gas (Btu/yr) = annual consumption (MMBtu/yr) / 1,000,000 (Btu/MMBtu)
[4] Per AP-42 Section 11.17
[5] Per EPA Webfire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln
[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)
[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol
[8] SO_2 emissions = potential SO_2 emissions x (1 - 99% inherent scrubbing efficiency)
[9] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.
[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input
[11] Fuel-based NOx emissions for coal and natural gas = NOx emission factor x throughput x ratio of fuel input to total heat input
[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent.
For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.
The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:
NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 6b. Emission Limits from Clark County Title V Permit - Kiln 4 [1]

NOx (tpy)	SO_2 (tpy)
702.05	539.13

[1] Per Table III-A-3

Table 6c. Fuel Blend Generating Lowest SO_2 Emissions - HiCal - Kiln 4

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2]	Percent Fuel Blend [3]	NOx Emission Factor - Value	NOx Emission Factor - Units	Sulfur Emissions [6]	Pre-Scrub SO_2 Emissions [7]	Post-Scrub SO_2 Emissions [8]	Baseline PM_{10} Emissions[9]	Fuel-Based NO_x Emissions [10, 11]	NOx Emissions Scaled to Baseline[12]
			Btu/yr				ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr
Coal	71,901	tons/yr	1.66E+12	85%	3.10	lb/ton lime [4]	301.99	603.97	6.04	23.48	555.83	639.09
Coke	10,635	tons/yr	2.92E+11	15%	0.09	lb/MMBtu coke [5]	586.00	1,172.00	11.72		13.88	15.96
Total			**1.95E+12**	**100%**			**887.99**	**1,775.97**	**17.76**	**23.48**	**569.71**	**655.05**

[1] Annual consumption (tons/yr) = Annual Heat Input (Btu/yr) / Fuel Heating Value (Btu/lb) / 2,000 (lb/ton)
[2] Annual fuel heat input (Btu/yr) = total baseline heat input (MMBtu/yr) x Required Fuel Blend (%)
[3] HiCal Fuel Blend must fall within 65%-75% Coal and 25%-35% Coke per Lhoist internal production analysis. Fuel Blend ranges provided on June 10, 2020.
[4] Per AP-42 Section 11.17
[5] Per EPA Webfire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln
[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)
[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol
[8] SO_2 emissions = potential SO_2 emissions x (1 - 99% inherent scrubbing efficiency)
[9] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.
[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input
[11] Fuel-based NOx emissions for coal = NOx emission factor x throughput x ratio of fuel input to total heat input
[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent.
For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.
The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:
NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 6d. Fuel Blend Generating Highest SO_2 Emissions - HiCal - Kiln 4

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2]	Percent Fuel Blend [3]	NOx Emission Factor - Value	NOx Emission Factor - Units	Sulfur Emissions [6]	Pre-Scrub SO_2 Emissions [7]	Post-Scrub SO_2 Emissions [8]	Baseline PM_{10} Emissions[9]	Fuel-Based NO_x Emissions [10, 11]	NOx Emissions Scaled to Baseline[12]
			Btu/yr				ton/yr	ton/yr	ton/yr	ton/yr	ton/yr	ton/yr
Coal	59,213	tons/yr	1.36E+12	70%	3.10	lb/ton lime [4]	248.69	497.39	4.97	23.48	457.75	526.31
Coke	21,270	tons/yr	5.85E+11	30%	0.09	lb/MMBtu coke [5]	1,172.00	2,344.00	23.44		27.76	31.91
Total			**1.95E+12**	**100%**			**1,420.69**	**2,841.39**	**28.41**	**23.48**	**485.50**	**558.23**

[1] Annual consumption (tons/yr) = Annual Heat Input (Btu/yr) / Fuel Heating Value (Btu/lb) / 2,000 (lb/ton)
[2] Annual fuel heat input (Btu/yr) = total baseline heat input (MMBtu/yr) x Required Fuel Blend (%)
[3] HiCal Fuel Blend must fall within 65%-75% Coal and 25%-35% Coke per Lhoist internal production analysis. Fuel Blend ranges provided on June 10, 2020.
[4] Per AP-42 Section 11.17
[5] Per EPA Webfire Factor ID 2627 for combustion of Petroleum Coke in a Boiler - assumed to be similar for a lime kiln
[6] Sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)
[7] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol
[8] SO_2 emissions = potential SO_2 emissions x (1 - 99% inherent scrubbing efficiency)
[9] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.
[10] Fuel-based NOx emissions for coke = NOx emission factor x coke heat input
[11] Fuel-based NOx emissions for coal = NOx emission factor x throughput x ratio of fuel input to total heat input
[12] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent.
For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.
The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:
NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 6e. 100% Natural Gas Combustion Emissions - Kiln 4

Fuels	Annual Consumption [1]	Units	Annual Heat Input [2] Btu/yr	Percent Fuel Blend	NOx Emission Factor - Value	NOx Emission Factor - Units	Sulfur Emissions [4] ton/yr	Pre-Scrub SO_2 Emissions [5] ton/yr	Post-Scrub SO_2 Emissions [6] ton/yr	PM_{10} Emissions[7] ton/yr	Fuel-Based NO_x Emissions [8] ton/yr	NOx Emissions Scaled to Baseline[9] ton/yr
Natural Gas	1,949,799	MMBtu/yr	1.95E+12	100%	3.50	lb/ton lime [3]	0.27	0.55	0.005	23.48	738.30	848.89

[1] Annual consumption of natural gas (MMBtu/yr) = total annual heat input, current scenario (Btu/yr) / 1,000,000 (Btu/MMBtu)

[2] Annual heat input, natural gas (Btu/yr) = total heat input, current scenario (Btu/yr)

[3] Per AP-42 Section 11.17

[4] Potential sulfur emissions (ton/yr) = annual consumption (ton/yr) x sulfur content (%)

[5] SO_2 emissions (ton/yr) = potential sulfur emissions (ton/yr) x 64 lb SO_2/lbmol / 32 lb S/lbmol

[6] SO_2 emissions = potential SO_2 emissions x (1 - 99% inherent scrubbing efficiency) 457.75

[7] PM_{10} emissions are calculated as the average of the PM_{10} emissions reported in Lhoist's emissions inventories for years 2016 to 2018. Particulate emissions are not expected to vary with fuel blends due to the use of baghouse controls.

[8] Fuel-based NOx emissions for natural gas = NOx emission factor x throughput x ratio of fuel input to total heat input

[9] Total baseline NOx emissions are calculated as the average of the NOx emissions reported in Lhoist's emissions inventories for years 2016 to 2018. The emissions inventory uses an overall lb/ton limit emission factor which is not fuel dependent. For this analysis, fuel-specific NOx emission factors have been used to determine the NOx contribution to the baseline from each fuel.
The fuel-based emissions calculated are then scaled up by the ratio of the total NOx emissions calculated on a fuels basis for the baseline period to the total NOx emissions calculated from the emissions inventories for the baseline period as follows:
NOx Emissions Scaled to Baseline (ton/yr) = Fuel-Based NOx Emissions (ton/yr) x (Baseline NOX Emissions (ton/yr) / Total Baseline Fuel-Based NOx Emissions (ton/yr))

Table 6f. Summary of Emissions - Kiln 4

Product	Fuel Blend Generating	SO_2 Emissions Total (ton/yr)	SO_2 Emissions Reduction (+ve) vs Increase (-ve) (%)	NOx Emissions Total (ton/yr)	NOx Emissions Reduction (+ve) vs Increase (-ve) (%)
Baseline	-	**14.30**	-	**686.68**	-
HiCal	Lowest SO_2	17.76	-24%	655.05	5%
HiCal	Highest SO_2	28.41	-99%	558.23	19%
HiCal	NG Only	0.005	100%	848.89	-24%

APPENDIX C : NO_X CONTROL COST CALCULATIONS

REGIONAL HAZE 2ND PLANNING PERIOD - FOUR FACTOR ANALYSIS

Table 1. Economic Analysis - Low-NOx Burner Only

Parameter	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Kilns 1-4 Combined	Notes
Capital Costs ($)						
LNB Installation Cost	$ 375,000	$ 375,000	$ -	$ 450,000	$ 1,200,000	Based on information provided by the plant as well as recent constructions at Apex's Kiln 3 and LNA's Nelson Facility Kilns. The cost includes the actual burner and the retrofit of the fuel delivery system to accommodate the burner.
Capital Recovery Factor	0.069	0.069	-	0.069	0.069	Based on current prime interest rate of 3.25%
Annualized Capital Costs ($/yr)	$ 25,792	$ 25,792	-	$ 30,950	$ 82,535	
Annual Emissions Reductions (ton/yr)						
Baseline Emission Rate	304	19	154	687	1,164	Based on 2016 - 2018 baseline actual emissions
Control Efficiency	10%	10%	0%	10%	10%	Based on KFS Vendor Documentation for LNA's Nelson Facility
NOx Reduced (tons/year)	30.35	1.91	0.00	68.67	116.35	A reduction in Kiln 3 emissions has been included as the permitted emission rate does not take into account the reductions from the Kiln's operational LNB.
Cost Effectiveness ($/ton)	**$ 850**	**$ 13,494**	**$ -**	**$ 451**	**$ 709**	

Table 2. Economic Analysis - SNCR Only

Parameter	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Kilns 1-4 Combined	Notes
Capital Costs ($)						
SNCR Installation Capital Cost	$ 591,441	$ 591,441	$ 591,441	$ 591,441	$ 2,365,764	Based on LNA costs from Lhoist Nelson vendor quotes. See Appendix D for additional cost information.
CEPCI (Aug 2020/2016)	1.10	1.10	1.10	1.10	1.10	
Capital Recovery Factor	0.069	0.069	0.069	0.069	0.069	Based on current prime interest rate of 3.25%
Annualized Capital Costs ($/yr)	$ 40,679	$ 40,679	$ 40,679	$ 40,679	$ 162,715	
Annual Operating Costs ($/yr)						
Urea Usage (tons per year)	48.95	3.08	24.87	276.89	353.80	Based on LNA's experience with urea injection at another LNA Plant (l lb urea reduces 1.24 lb NO)
Urea cost ($ per ton)	$ 430	$ 430	$ 430	$ 430	$ 430	[redacted]
Urea cost ($ per year)	$ 21,037	$ 1,325	$ 10,688	$ 118,988	$ 152,037	
Operating labor ($ per year)	$ 41,127	$ 41,127	$ 41,127	$ 41,127	$ 164,510	Based on LNA's experience with urea injection at another LNA Plant
Power usage (kW per hr)	2.26	2.26	2.26	2.26	2.26	Based on LNA's experience with urea injection at another LNA Plant.
Power usage (kW per year)	16,272	16,272	16,272	16,272	16,272	Assumes 7,200 hours of operation
Power cost ($ per kilowatt)	$ 0.0756	$ 0.0756	$ 0.0756	$ 0.0756	$ 0.0756	https://www.electricitylocal.com/states/nevada/henderson/
Power cost ($ per year)	$ 1,230	$ 1,230	$ 1,230	$ 1,230	$ 1,230	
Maintenance Materials ($ per year)	$ 60,320	$ 60,320	$ 60,320	$ 60,320	$ 241,281	Based on LNA's experience with urea injection at another LNA Plant
Total Direct Annual Costs ($/yr)	$ 123,715	$ 104,003	$ 113,365	$ 221,665	$ 562,749	
Total Annual Costs ($/yr)	$ 164,394	$ 144,681	$ 154,044	$ 262,344	$ 725,463	
Annual Emissions Reductions (ton/yr)						
Baseline Emission Rate	304	19	154	687	1,164	Based on 2016 - 2018 baseline actual emissions
Control Efficiency	20%	20%	20%	50%	38%	Based on LNA's experience with SNCR technology at other LNA plants based on age and technology of the different kilns
NOx Reduced	60.70	3.82	30.84	343.34	438.71	
Cost Effectiveness ($/ton)	**$ 2,708**	**$ 37,847**	**$ 4,995**	**$ 764**	**$ 1,654**	

Table 3. Economic Analysis - Installing Low-NOx Burners Before SNCR

Parameter	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Kilns 1-4 Combined	Notes
Capital Costs ($)						
SNCR Installation Capital Cost	$ 591,441	$ 591,441	$ 591,441	$ 591,441	$ 2,365,764	Based on LNA costs from Lhoist Nelson vendor quotes. See Appendix D for additional cost information.
Capital Recovery Factor	0.069	0.069	0.069	0.069	0.069	Based on current prime interest rate of 3.25%
Annualized Capital Costs ($/yr)	$ 40,679	$ 40,679	$ 40,679	$ 40,679	$ 162,715	
Annual Operating Costs ($/yr)						
Urea Usage (tons per year)	44.06	2.77	24.87	249.20	320.90	Based on LNA's experience with urea injection at another LNA Plant (I lb urea reduces 1.24 lb NOX)
Urea cost ($ per ton)	$ 430	$ 430	$ 430	$ 430	$ 430	[redacted]
Urea cost ($ per year)	$ 18,933	$ 1,192	$ 10,688	$ 107,089	$ 137,902	
Operating labor ($ per year)	$ 41,127	$ 41,127	$ 41,127	$ 41,127	$ 164,510	Based on LNA's experience with urea injection at another LNA Plant
Power usage (kW per hr)	2.26	2.26	2.26	2.26	2.26	Based on LNA's experience with urea injection at another LNA Plant.
Power usage (kW per year)	16,272	16,272	16,272	16,272	16,272	Assumes 7,200 hours of operation
Power cost ($ per kilowatt)	$ 0.0756	$ 0.0756	$ 0.0756	$ 0.0756	$ 0.0756	https://www.electricitylocal.com/states/nevada/henderson/
Power cost ($ per year)	$ 1,230	$ 1,230	$ 1,230	$ 1,230	$ 1,230	
Maintenance Materials ($ per year)	$ 60,320	$ 60,320	$ 60,320	$ 60,320	$ 241,281	Based on LNA's experience with urea injection at another LNA Plant
Total Direct Annual Costs ($/yr)	$ 121,611	$ 103,870	$ 113,365	$ 209,767	$ 548,614	
Total Annual Costs ($/yr)	$ 162,290	$ 144,549	$ 154,044	$ 250,445	$ 711,328	
Annual Emissions Reductions (ton/yr)						
Baseline Emission Rate	304	19	154	687	1,164	Based on 2016 - 2018 baseline actual emissions
LNB Control Efficiency	10%	10%	0%	10%	10%	Based on KFS Vendor Documentation for LNA's Nelson Facility
Post-LNB Baseline Emissions	273	17	154	618	1,047	
SNCR Control Efficiency	20%	20%	20%	50%	38%	Based on LNA's experience with SNCR technology at other LNA plants based on age and technology of the different kilns
NOx Reduced	54.63	3.44	30.84	309.01	397.92	
Cost Effectiveness ($/ton)	**$ 2,971**	**$ 42,014**	**$ 4,995**	**$ 810**	**$ 1,788**	Cost effectiveness reflects the cost of installing SNCR if LNBs are installed first. This does not include the initial cost of installing LNBs at the kiln.

Table 4. Economic Analysis - Average Cost of Both Low-NOx and SNCR

Parameter	Kiln 1	Kiln 2	Kiln 3	Kiln 4	Kilns 1-4 Combined
Capital Costs					
LNB	$ 375,000	$ 375,000	$ -	$ 450,000	$ 1,200,000
SNCR	$ 591,441	$ 591,441	$ 591,441	$ 591,441	$ 2,365,764
LNB + SNCR	$ 966,441	$ 966,441	$ 591,441	$ 1,041,441	$ 3,565,764
Annualized Capital Costs ($/yr)					
LNB	$ 25,792	$ 25,792	-	$ 30,950	$ 82,535
SNCR	$ 40,679	$ 40,679	$ 40,679	$ 40,679	$ 162,715
LNB + SNCR	$ 66,471	$ 66,471	$ 40,679	$ 71,629	$ 245,249
Annual Operating Costs ($/yr)					
LNB	-	-	-	-	$ -
SNCR	$ 121,611	$ 103,870	$ 113,365	$ 209,767	$ 548,614
LNB + SNCR	$ 121,611	$ 103,870	$ 113,365	$ 209,767	$ 548,614
Total Annual Costs ($/yr)					
LNB	$ 25,792	$ 25,792	$ -	$ 30,950	$ 82,535
SNCR	$ 162,290	$ 144,549	$ 154,044	$ 250,445	$ 711,328
LNB + SNCR	$ 188,082	$ 170,341	$ 154,044	$ 281,396	$ 793,863
Annual Emissions Reductions (ton/yr)					
LNB	30.35	1.91	0.00	68.67	116.35
SNCR	54.63	3.44	30.84	309.01	397.92
LNB + SNCR	84.98	5.35	30.84	377.68	498.85
Cost Effectiveness ($/ton)					
LNB	$ 850	$ 13,494	-	$ 451	$ 709
SNCR	$ 2,971	$ 42,014	$ 4,995	$ 810	$ 1,788
LNB + SNCR	$ 2,213	$ 31,828	$ 4,995	$ 745	$ 1,591

APPENDIX D : SUPPORTING DOCUMENTATION

SEMI-DRY SCRUBBING QUOTE

APPLICATION, SIZING, & OPERATING DATA:

(NOTE: All values given are for normal operating conditions, unless identified otherwise)

1. PROCESS INFORMATION: The system design is based on the following design parameters.

	Kiln 1	Kiln 2
Volume (dscfm)	67,000	82,000
Volume (acfm)	126,792	158.491
Temperature (°F)	500	540
Gas Composition (% vol)		
CO_2	20	20
H_2O	4	2
N_2	66	68
O_2	10	10
SO_2 (lb/hr)	92	436

2. SYSTEM PERFORMANCE: The following is the system design performance. In a firm proposal there will be conditions and limitations on any performance guarantee.
   2.1. SO_2 90% reduction

3. SPRAY DRYER

		Kiln 1	Kiln 2
3.1.	Inlet volume (acfm):	126,792	158.491
3.2.	Inlet temperature (°F):	500	540
3.3.	Outlet volume (acfm):	92,269	112,237
3.4.	Outlet temperature (°F):	160	160
3.5.	Water supply (gpm):	50	67
3.6.	Quicklime supply (lb/hr):	150	500
3.7.	Atomizing air required (scfm @ 100 psig):	800	1100
3.8.	Slurry nozzles:	6	6
3.9.	Size (overall):	20' OD x 95'H	24' OD x 95'H
3.10.	Retention time	11.5 sec	12 sec
3.11.	Slaker capacity (lb/hr):	2500	2500

HISTORICAL WATER SUPPLY

LHOIST NORTH AMERICA

FILE NAME Historical Water Supply.xlsx

YEAR: 2019

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
				WATER PUMPED IN MILLIONS OF GALLONS													
OLD	63261	216	32.58	0.82	1.07	0.72	2.27	1.63	2.15	2.24	3.08	2.47	2.57	0.84	0.80	20.66	
NEW	64880		49.00	2.40	2.03	2.51	2.92	3.55	3.30	4.00	4.76	3.60	3.50	3.40	1.33	37.30	
	TOTALS :	**M G**	**81.58**	**3.22**	**3.10**	**3.23**	**5.19**	**5.18**	**5.45**	**6.24**	**7.84**	**6.07**	**6.07**	**4.24**	**2.13**	**57.97**	**(23.61)**
		A F	**250.36**	**9.88**	**9.52**	**9.93**	**15.93**	**15.90**	**16.73**	**19.15**	**24.05**	**18.64**	**18.62**	**13.03**	**6.52**	**177.90**	**(72.46)**

TCD = 250.376 AFA

LHOIST NORTH AMERICA

FILE NAME Historical Water Supply.xlsx

YEAR: 2018

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
				WATER PUMPED IN MILLIONS OF GALLONS													
OLD	63261	216	32.58	2.18	1.11	0.53	2.10	2.06	3.31	2.30	2.51	3.63	1.68	1.28	0.90	23.57	
NEW	64880		49.00	0.00	1.51	2.78	4.88	3.12	4.60	2.68	2.57	3.07	2.30	1.45	1.90	30.86	
	TOTALS :	**M G**	**81.58**	**2.18**	**2.61**	**3.31**	**6.97**	**5.18**	**7.91**	**4.98**	**5.08**	**6.71**	**3.98**	**2.73**	**2.80**	**54.43**	**(27.15)**
		A F	**250.36**	**6.68**	**8.02**	**10.15**	**21.39**	**15.89**	**24.28**	**15.29**	**15.58**	**20.58**	**12.22**	**8.37**	**8.58**	**167.04**	**(83.32)**

TCD = 250.376 AFA

LHOIST NORTH AMERICA

FILE NAME Historical Water Supply.xlsx

YEAR: 2017

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
				WATER PUMPED IN MILLIONS OF GALLONS													
OLD	63261	216	32.58	0.00	0.41	0.37	1.69	1.45	3.20	2.24	2.84	2.07	2.24	0.82	0.79	18.11	
NEW	64880		49.00	0.99	2.93	2.39	4.08	1.11	4.48	3.45	4.82	3.36	4.54	3.47	2.56	38.18	
	TOTALS :	M G	81.58	0.99	3.34	2.77	5.76	2.55	7.68	5.69	7.65	5.43	6.78	4.29	3.35	56.29	(25.29)
		A F	250.36	3.05	10.24	8.50	17.68	7.84	23.57	17.47	23.48	16.67	20.82	13.15	10.27	172.75	(77.61)

CHEMICAL LIME FILE NAME Historical Water Supply.xlsx

YEAR: 2016 DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	WATER PUMPED IN MILLIONS OF GALLONS JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
OLD	63261	216	32.58	0.43	0.45	0.78	1.10	1.73	1.90	3.68	2.28	1.55	2.24	0.82	0.79	17.76	
NEW	64880		49.00	1.18	1.86	3.16	2.29	1.80	3.67	4.10	0.31	2.23	4.54	3.47	2.56	31.17	
	TOTALS :	M G	81.58	1.61	2.31	3.94	3.39	3.53	5.57	7.79	2.59	3.79	6.78	4.29	3.35	48.93	(32.65)
		A F	250.36	4.94	7.09	12.09	10.39	10.84	17.08	23.90	7.95	11.63	20.82	13.15	10.27	150.15	(100.21)

CHEMICAL LIME

FILE NAME Historical Water Supply.xlsx

YEAR: 2015

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	WATER PUMPED IN MILLIONS OF GALLONS JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
OLD	63261	216	32.58	2.12	1.87	2.59	3.58	2.90	2.86	1.75	1.97	1.59	0.93	0.42	1.09	23.67	
NEW	64880		49.00	2.35	2.01	2.70	2.74	1.77	3.39	7.80	5.50	3.88	4.16	1.92	1.37	39.59	
	TOTALS :	M G	81.58	4.47	3.89	5.28	6.32	4.67	6.25	9.55	7.47	5.47	5.09	2.34	2.46	63.26	(18.32)
		A F	250.36	13.72	11.93	16.21	19.40	14.33	19.18	29.31	22.92	16.79	15.62	7.18	7.55	194.14	(56.22)

CHEMICAL LIME

FILE NAME Historical Water Supply.xlsx

YEAR: 2014

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	WATER PUMPED IN MILLIONS OF GALLONS JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
OLD	63261	216	32.58	1.94	1.96	1.59	1.83	0.34	0.77	2.21	3.88	2.98	1.98	0.22	0.01	19.72	
NEW	64880		49.00	2.97	2.18	2.75	2.64	0.39	0.44	3.27	3.25	2.55	2.58	0.11	0.02	23.13	
	TOTALS :	**M G**	**81.58**	**4.91**	**4.15**	**4.34**	**4.47**	**0.73**	**1.21**	**5.48**	**7.13**	**5.53**	**4.56**	**0.33**	**0.04**	**42.85**	**(38.73)**
		A F	**250.36**	**15.08**	**12.72**	**13.32**	**13.71**	**2.23**	**3.70**	**16.80**	**21.88**	**16.96**	**13.98**	**1.01**	**0.11**	**131.51**	**(118.85)**

CHEMICAL LIME FILE NAME Historical Water Supply.xlsx

YEAR: 2013 DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	WATER PUMPED IN MILLIONS OF GALLONS JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
OLD	63261	216	32.58	1.21	1.19	2.04	2.21	2.31	1.71	2.18	2.99	2.88	3.39	2.17	1.85	26.12	
NEW	64880		49.00	1.30	0.87	0.76	0.64	0.75	0.58	3.34	3.60	2.18	2.89	2.26	1.56	20.72	
	TOTALS :	**M G**	**81.58**	**2.51**	**2.06**	**2.79**	**2.85**	**3.06**	**2.29**	**5.52**	**6.59**	**5.06**	**6.28**	**4.42**	**3.41**	**46.84**	**(34.74)**
		A F	**250.36**	**7.69**	**6.33**	**8.57**	**8.74**	**9.39**	**7.02**	**16.93**	**20.23**	**15.54**	**19.26**	**13.57**	**10.47**	**143.74**	**(106.62)**

CHEMICAL LIME

FILE NAME Historical Water Supply.xlsx

YEAR: 2012

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
				WATER PUMPED IN MILLIONS OF GALLONS													
OLD	63261	216	32.58	2.14	2.91	1.89	0.42	1.17	1.85	1.02	1.22	1.36	2.01	1.57	1.54	19.10	
NEW	64880		49.00	2.42	2.22	3.20	4.12	4.53	4.43	4.41	3.87	2.08	2.53	2.01	1.14	36.96	
	TOTALS :	**M G**	**81.58**	**4.56**	**5.13**	**5.09**	**4.54**	**5.70**	**6.29**	**5.42**	**5.09**	**3.44**	**4.54**	**3.58**	**2.68**	**56.06**	**(25.52)**
		A F	**250.36**	**13.98**	**15.75**	**15.61**	**13.92**	**17.50**	**19.29**	**16.64**	**15.63**	**10.56**	**13.94**	**10.98**	**8.22**	**172.04**	**(78.32)**

CHEMICAL LIME

FILE NAME Historical Water Supply.xlsx

YEAR: 2011

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	WATER PUMPED IN MILLIONS OF GALLONS JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
OLD	63261	216	32.58	1.42	1.39	1.66	2.70	3.41	3.00	2.84	2.49	2.41	2.95	2.15	2.52	28.94	
NEW	64880		49.00	1.87	2.07	3.08	4.36	4.75	3.89	4.54	3.77	3.01	4.31	1.72	1.32	38.68	
	TOTALS :	**M G**	**81.58**	**3.30**	**3.46**	**4.74**	**7.06**	**8.16**	**6.90**	**7.39**	**6.25**	**5.42**	**7.26**	**3.87**	**3.84**	**67.63**	**(13.95)**
		A F	**250.36**	**10.11**	**10.62**	**14.55**	**21.65**	**25.04**	**21.16**	**22.67**	**19.19**	**16.62**	**22.27**	**11.88**	**11.78**	**207.54**	**(42.82)**

CHEMICAL LIME

FILE NAME Historical Water Supply.xlsx

YEAR: 2010

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
				WATER PUMPED IN MILLIONS OF GALLONS													
OLD	63261	216	32.58	1.97	1.40	1.19	2.23	2.64	2.39	2.11	2.23	1.96	1.60	1.81	0.88	22.42	
NEW	64880		49.00	2.25	1.91	2.44	2.47	2.81	1.72	2.82	3.73	2.66	2.75	2.39	1.76	29.70	
	TOTALS :	**M G**	**81.58**	**4.22**	**3.31**	**3.63**	**4.70**	**5.45**	**4.10**	**4.93**	**5.96**	**4.62**	**4.35**	**4.21**	**2.64**	**52.12**	**(29.46)**
		A F	**250.36**	**12.96**	**10.15**	**11.15**	**14.41**	**16.73**	**12.59**	**15.12**	**18.28**	**14.18**	**13.34**	**12.92**	**8.11**	**159.94**	**(90.42)**

CHEMICAL LIME FILE NAME Historical Water Supply.xlsx

YEAR: 2009 DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
				WATER PUMPED IN MILLIONS OF GALLONS													
OLD	63261	216	32.58	1.19	2.03	2.19	2.18	2.50	2.30	2.71	3.32	2.87	3.17	2.03	1.50	27.97	
NEW	64880		49.00	1.59	0.34	1.74	2.40	0.88	0.40	0.94	4.25	3.80	3.84	3.36	3.32	26.84	
	TOTALS :	M G	81.58	2.77	2.37	3.93	4.58	3.38	2.69	3.64	7.58	6.66	7.01	5.39	4.82	54.82	(26.76)
		A F	250.36	8.51	7.26	12.05	14.06	10.36	8.26	11.18	23.25	20.44	21.52	16.55	14.79	168.24	(82.12)

CHEMICAL LIME

FILE NAME Historical Water Supply.xlsx

YEAR: 2008

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
				WATER PUMPED IN MILLIONS OF GALLONS													
OLD	63261	216	32.58	2.40	2.17	2.22	3.68	3.89	3.90	2.84	2.23	2.58	3.60	2.24	0.80	32.56	
NEW	64880		49.00	6.27	4.24	4.17	4.84	6.45	6.76	4.03	2.52	1.65	0.49	0.65	1.49	43.56	
	TOTALS :	M G	81.58	8.68	6.41	6.39	8.52	10.35	10.66	6.87	4.75	4.24	4.09	2.89	2.29	76.12	(5.46)
		A F	250.36	26.63	19.67	19.60	26.14	31.75	32.73	21.08	14.57	13.01	12.55	8.87	7.02	233.62	(16.74)

CHEMICAL LIME

FILE NAME Historical Water Supply.xlsx

YEAR: 2007

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
				WATER PUMPED IN MILLIONS OF GALLONS													
OLD	63261	216	32.58	4.22	3.69	3.59	3.65	2.24	3.64	3.40	3.63	3.52	4.04	3.57	1.89	41.09	
NEW	64880		49.00	3.30	2.63	2.65	3.23	5.49	5.72	3.91	3.69	4.52	6.34	5.33	4.93	51.73	
	TOTALS :	**M G**	**81.58**	**7.52**	**6.31**	**6.25**	**6.88**	**7.73**	**9.36**	**7.31**	**7.31**	**8.04**	**10.38**	**8.90**	**6.82**	**92.82**	**11.24**
		A F	**250.36**	**23.08**	**19.38**	**19.17**	**21.11**	**23.73**	**28.73**	**22.44**	**22.45**	**24.67**	**31.86**	**27.32**	**20.93**	**284.86**	**34.50**

CHEMICAL LIME

FILE NAME Historical Water Supply.XLS

YEAR: 2006

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
				WATER PUMPED IN MILLIONS OF GALLONS													
OLD	63261	216	32.58	3.60	3.34	3.50	3.28	3.97	3.62	3.40	3.59	3.46	3.59	3.64	3.63	42.61	
NEW	64880		49.00	3.52	3.30	3.57	3.31	3.85	3.21	3.51	3.52	3.21	3.26	2.85	2.11	39.21	
	TOTALS :	M G	81.58	7.11	6.65	7.07	6.59	7.82	6.83	6.91	7.11	6.67	6.85	6.48	5.74	81.82	0.24
		A F	250.36	21.82	20.39	21.71	20.24	23.99	20.95	21.19	21.82	20.47	21.01	19.90	17.61	251.10	0.74

CHEMICAL LIME

FILE NAME Historical Water Supply.XLS

YEAR: 2005

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
				WATER PUMPED IN MILLIONS OF GALLONS													
OLD	63261	216	32.58	1.90	2.93	3.30	0.83	3.00	4.17	3.06	3.78	3.16	3.60	3.15	3.30	36.17	
NEW	64880		49.00	2.65	1.51	1.76	0.91	3.83	3.91	3.33	4.22	3.07	3.71	3.15	3.36	35.42	
	TOTALS :	M G	81.58	4.56	4.45	5.06	1.75	6.83	8.08	6.38	8.00	6.22	7.31	6.30	6.66	71.59	(9.99)
		A F	250.36	13.98	13.64	15.53	5.36	20.95	24.80	19.59	24.55	19.10	22.42	19.34	20.43	219.69	(30.67)

CHEMICAL LIME

FILE NAME: ChemicalLime2004.xls

YEAR: 2004

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
				WATER PUMPED IN MILLIONS OF GALLONS													
OLD	63261	216	32.58	2.34	2.98	3.66	3.41	3.29	3.08	3.88	3.49	2.51	3.30	3.49	3.17	38.61	
NEW	64880		49.00	3.00	2.32	4.81	4.32	4.15	3.77	4.69	4.30	3.99	3.37	0.75	1.86	41.34	
	TOTALS :	M G	81.58	5.34	5.31	8.47	7.73	7.44	6.86	8.57	7.80	6.50	6.68	4.24	5.03	79.94	(1.64)
		A F	250.36	16.38	16.29	25.99	23.72	22.83	21.04	26.30	23.93	19.93	20.49	13.02	15.43	245.34	(5.02)

CHEMICAL LIME

YEAR: 2003

FILE NAME: ChemicalLime2003.xls

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
				WATER PUMPED IN MILLIONS OF GALLONS													
OLD	63261	216	32.58	2.14	2.49	2.81	3.17	3.13	3.22	3.17	3.17	2.25	3.39	2.13	2.06	33.12	
NEW	64880		49.00	3.39	2.86	3.56	4.17	4.13	4.12	4.04	4.04	2.83	4.28	2.72	3.14	43.27	
	TOTALS :	**M G**	**81.58**	**5.53**	**5.35**	**6.37**	**7.35**	**7.25**	**7.34**	**7.21**	**7.21**	**5.08**	**7.66**	**4.85**	**5.20**	**76.39**	**(5.19)**
		A F	**250.36**	**16.97**	**16.42**	**19.54**	**22.55**	**22.25**	**22.53**	**22.12**	**22.12**	**15.59**	**23.51**	**14.89**	**15.95**	**234.44**	**(15.92)**

CHEMICAL LIME

FILE NAME: ChemicalLime2002.xls

YEAR: 2002

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
				WATER PUMPED IN MILLIONS OF GALLONS													
OLD	63261	216	32.58	2.71	2.90	3.15	1.83	3.65	2.59	2.70	3.58	3.47	3.67	3.51	1.81	35.55	
NEW	64880		49.00	3.75	4.01	4.35	4.87	4.96	4.56	4.19	4.44	4.10	3.63	2.41	2.03	47.30	
	TOTALS :	M G	**81.58**	**6.47**	**6.91**	**7.50**	**6.69**	**8.60**	**7.15**	**6.89**	**8.03**	**7.58**	**7.30**	**5.92**	**3.83**	**82.86**	**1.28**
		A F	**250.36**	**19.84**	**21.21**	**23.01**	**20.54**	**26.40**	**21.94**	**21.14**	**24.64**	**23.25**	**22.40**	**18.15**	**11.77**	**254.28**	**3.92**

CHEMICAL LIME

YEAR: 2001

FILE NAME: ChemicalLime2001.xls

DATE: 03/30/20

SITE I.D.	PERMIT NO.	BASIN	DUTY ALLOWED	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL USED	DIFFERENCE; OVER/(UNDER) ALLOWED AMT
				WATER PUMPED IN MILLIONS OF GALLONS													
OLD	63261	216	32.58	2.38	2.92	2.38	3.24	3.02	3.24	2.81	2.73	2.70	3.04	2.45	2.48	33.39	
NEW	64880		49.00	2.64	2.11	1.68	3.60	4.45	3.14	4.21	4.19	4.09	4.75	3.61	3.44	41.92	
	TOTALS :	**M G**	**81.58**	**5.02**	**5.03**	**4.06**	**6.84**	**7.47**	**6.38**	**7.02**	**6.92**	**6.79**	**7.80**	**6.06**	**5.92**	**75.31**	**(6.27)**
		A F	**250.36**	**15.41**	**15.44**	**12.46**	**20.99**	**22.92**	**19.58**	**21.54**	**21.24**	**20.84**	**23.93**	**18.61**	**18.16**	**231.12**	**(19.24)**

KFS BURNER VENDOR STATEMENT

From:	Cliff Rennie
To:	TIANI Issam
Cc:	Ken R; Leo Newell
Subject:	RE: Quick question K3 burner
Date:	Friday, January 24, 2020 9:02:36 AM

Hi Issam

These days, all KFS burners are "Low NOx" in one way or another due to the design techniques used (plus the demand from customers!).

The techniques used by KFS for the DFN burner installed in Apex K3, and its other variants, include:

- Bluff body (of sufficient size) to create enhanced mixing at the nozzle – this enhances rapid ignition and reduces plume length, which in turn reduces "premixing" of fuel and air, effectively creating a fuel rich zone at the root of the flame
- DFN blades to create enhanced mixing, which again assist in rapid ignition
- Ability to inject gas into the root of the flame, assisting with rapid ignition and creation of a fuel rich zone at the root
- Minimizing primary air – this is not always easy with direct-fired mill systems where the mill itself can dictate primary air flowrate, but the DFN burner design has proven to provide a good flame/heat flux profile over a wider range of mill air flowrates than traditional straight-pipe burners. Thus, where there is the ability to turn down mill air and so reduce primary air, the DFN burner can cater for this to take advantage of NOX reduction with reduced primary air levels
- Finally, the improved fuel/air mixing and improved combustion with the DFN burner means that kiln feed-end O2 (and so overall O2 levels) can be minimized to reduce NOx without excessive CO

Hopefully, this is what you need and is in line you're your own thoughts, but please let Ken or I know if any clarification is needed on the above.

Best regards
Cliff

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From: TIANI Issam <issam.tiani@lhoist.com>
Sent: 24 January 2020 13:52
To: Cliff Rennie <cliff.rennie@kfs-solutions.com>
Cc: Ken R <ken.rhodes@kfs-solutions.com>
Subject: Quick question K3 burner
Importance: High

Hello Cliff,

I hope all is well. Quick question regarding Low NOX burner from KFS-Metso. Would you say that the burner installed on K3 is a low NOx burner? I have my idea but would rather confirm with you before I reply to our regional environmental manager working on the Haze assessment.

I appreciate your answer.

Thank you,

Issam
Technical Manager

Lhoist Group
Apex Plant
12101 North Las Vegas Blvd., Las Vegas, NV 89165
Office: +1 702 227 4949 Extention: 643039
Cell: +1 702 343 3820
issam.tiani@lhoist.com
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NELSON KFS BURNER EFFICIENCY

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United Kingdom

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www.kfs-solutions.com

Carla Lopez
Regional Sourcing Manager –West and Texas
Lhoist North America
Apex Location
12101 N Las Vegas Blvd
Las Vegas
NV 89165
USA

KFS Ref: E6229 Rev 4

Date: 19-Jan-18

PROPOSAL FOR LOW NOx BURNER
K2 NELSON PLANT

Dear Carla

Further to our recent discussions and agreement on 10-Jan-18, I am pleased to provide the attached revised KFS proposal (REV 4) for a low NOx burner for K2 at Nelson Plant, AZ.

1. The proposal now covers only the selected option for the proven KFS DFN Low NOx technology for solid fuel firing:

    - KFS Low NOx DFN Nozzle modification for existing straight-pipe burner to allow reuse of existing coal mill fan location
        - includes an integrated KFS HSB diesel warm-up burner with HE ignitor mounted on the burner within the refractory lining

2. The burner design will allow the use of the following fuels. Note that the ability to achieve the proposed NOx reduction and fire high petcoke rates will be dependent on a correct preparation of the fuel and favorable process operating conditions, including maintaining normal secondary air temperature:

Fuel	Nominal Burner Heat Release (gross basis) MMBtu/h	Turndown	Use
	K2		
75% Petcoke / 25% Coal	225	5:1	Kiln production
Diesel (rated for up to 12 USgpm)	60	Min. 10:1	Kiln warm-up

3. The burner design is based on updated CFD modeling undertaken by KFS and as reported in Powerpoint presentation dated 22-Dec-17.

4. Pricing for the warm-up burner and associated primary air fan reflect list prices in the BMS Agreement. All additional equipment for any BMS upgrade will be handled separately under the auspices of the current BMS Agreement.

5. Pricing is provided for the main burner hood-mounted chassis.

6. The proposed clean primary air fan is principally for diesel warm-up burner operation, but could also be used for burner emergency cooling air.

7. A preliminary commissioning and 2 years spare parts list is provided. A fully detailed spare parts list will be provided once engineering is completed and all equipment fully specified and confirmed. Note that spare parts could be rationalized across both kilns (and Apex Plant, where possible and appropriate) to reduce the total cost based on discussions with LNA on appropriate spares inventory.

8. Day rates are provided for on-site assistance with burner commissioning.

I trust the revised proposal meets your requirements. In the meantime, please do not hesitate to contact either Ken Rhodes or I if you need further information or clarification.

Yours sincerely

Cliff Rennie
CEO & Director

Kiln Flame Systems Ltd
Copyground Lane
High Wycombe HP12 3HE
United Kingdom

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PROPOSAL

Carla Lopez
Regional Sourcing Manager –West and Texas
Lhoist North America
Apex Location
12101 N Las Vegas Blvd
Las Vegas
NV 89165
USA

KFS Ref: E6229 Rev 4

Date: 19-Jan-18

PROPOSAL FOR LOW NOx BURNER
K2 NELSON PLANT

1. INTRODUCTION

This proposal covers the scope of the Kiln Flame Systems (KFS) activities and deliverables for design and supply of a KFS Low NOx DFN burners for K2 at LNA Nelson Plant, AZ.

2. SCOPE OF SUPPLY AND PRICES

2.1 Equipment Items

The detailed scope of supply and deliverables is outlined in the Technical Appendix.

2.1.1 KFS Low NOx DFN Nozzle with Integrated KFS HSB Diesel Warm-up Burner for K2

Item Description	Tech. App. Ref.	Unit Prices, $ DDP Site
Burner System Engineering and Modeling	A2.1	Included in equipment prices
KFS Low NOx DFN Nozzle ($73,519) with Integrated KFS HSB Diesel Warm-up Burner including flex hoses ($37,607)	A2.2	111,126
Hood-Mounting Chassis	A2.2.1	22,185
Primary Air Fan and Associated Items for Warm-up Burner	A2.2.2	17,200
Total Price		**150,511**

Registered: 3811008 VAT: 697 9990 30

2.2 Assistance during Commissioning

As described in Section A2.3 of the Technical Appendix. Attendance for commissioning will be charged at the KFS day rate of USD1,950 which includes car rental and accommodation expenses. Overtime above a minimum 12 hour working day will be charged at USD244 per hour. Flight charges will be invoiced at cost.

Any requirement for 24 hr cover during critical phases of the commissioning should be advised and may require an additional KFS engineer to attend site.

3. TERMS AND CONDITIONS

This quotation and any ensuing contract is subject to the standard Kiln Flame Systems Ltd Terms and Conditions of Sale unless otherwise agreed in writing except for the terms and conditions outlined in Sections 4.0 of this quotation.

4. SPECIAL CONDITIONS OF SALE

4.1 Price Basis

Prices are in US dollars for equipment delivered DDP site. Prices are firm and not subject to escalation within the stated project schedule.

4.2 Validity

This quotation is valid for 30 days.

4.3 Delivery

Equipment delivered to site (or refractory installer's shop) no later than 13-Mar-18.

4.4 Terms of Payment

KFS request all financial transactions to be net 45 days by electronic bank transfer. The following stage payments are proposed.

4.4.1 Equipment

- 10% on issue of GA drawing
- 30% at the mid-point of the fabrication period
- 40% on delivery
- 20% on successful commissioning and compliance with performance guarantees, but no later than 60 days after commissioning

4.4.2 Commissioning Services

- 100% on completion

5. GUARANTEES

The following guarantees are provided:

5.1 Mechanical Warranty

The KFS burners are subject to a mechanical warranty of 12 months from date of first commissioning or 18 months from delivery, whichever occurs first. This warranty does not apply to normal wear parts (e.g. atomizers).

Any other KFS supplied equipment is subject to a mechanical warranty of 12 months from date of commissioning or 18 months from delivery, whichever occurs first. This warranty does not apply to normal wear parts.

5.2 Performance Guarantees

The following burner and process performance parameters are guaranteed:

- Thermal capacity with specified fuels:
  - as detailed in table in cover letter

- No adverse impact on productivity from the kiln. Adverse impact would be a decrease of greater than 5% in the daily production rate for the kiln, 1050 tons/day normal operations.

- No accelerated refractory wear, provided normal operating conditions and temperatures are maintained in the kiln, no over burning of the lime, and the burner is set-up and orientated per KFS recommendations.

- Capacity range with specified fuels:
  - solid fuel turndown dependent on coal mill
  - at least 10:1 turndown for diesel firing
  - Fuel consumption does not increase, increase defined as 5% above current operating conditions in Table II below.

- Emissions:
  - proposed emissions guarantees are as shown in Table I below
  - conditions for emissions guarantees based on current operating conditions shown in Table II below :
    - burner heat release within design values detailed in cover letter
    - fuel blends as detailed in cover letter, +/- 5%
    - solid fuel grind not less than 90% passing 200 mesh
    - maximum secondary air temperature 1,450°F

- maximum primary air to burner 27% of stoichiometric
- maximum feed-end O_2 1.0 vol%, dry basis
- minimum feed-end CO 1000 ppm
- no over-burning of lime product (parameters to be defined based on historical data)

Being that the kilns are a dynamic environment, it is recognized that the nominal operating parameters below may fluctuate +/- 5% as part of responding to variation in the process. KFS and the plant team agree to discuss any concerns on the potential impact on the guarantee if these values are exceeded. Plant agrees to hold no more than the +/- 5% if KFS feels it is impacting the performance of the burner.

All guarantees to be verified and mutually agreed by LNA and KFS within 60 days of commissioning based on review and evaluation of kiln process data.

In the case of non-compliance with the performance guarantee, KFS will provide its best endeavours in terms of off-site support (phone/email), engineering design, replacement equipment components, and assistance on site, as appropriate and at KFS cost, to remedy any non-compliance with performance guarantee parameters within a period of 6 months from first light-up.

Note that since this is an equipment supply only project, KFS cannot accept costs of installation of any modified parts.

In the event of project failure, KFS can only accept that 50% of total payments (equipment and commissioning assistance) are refunded. Anything beyond this represents excessive risk and does not fit in with the KFS sustainable business model.

In addition, to balance risk in this scenario and as part of the partnership approach, if the project is proved successful, as determined by achievement of guarantees, KFS would request that the discount provided for the project is available to be invoiced in addition to the normal final payment.

Emission	**Units**	**Current Value**	**Achievable Value**	**Fuel Blend**
		K2	K2	
NOx	lb/h	164	10 to 15% reduction	• 75% petcoke/25% coal • diesel warm-up
Note 1 (general): Achievement of NOx emissions values will be possible only under conditions of stable and normal kiln operation with the burner operated in accordance with KFS instructions and recommendations.				

Table I : Proposed NOx Emissions Guarantee Values

Nelson K2 Operating Parameters 2017

Process Variables	Normal Operating Conditions
Feed End Oxygen	0.3 to 0.5 %
Feed-end CO	4325 ppm
Feed-end Temperature	2130°F
Hood Pressure	0.01 to -0.01 in WC
Preheater Inlet Temperature	2050°F
Preheater Exit Temperature	570°F
Fuel	7.87 tph
Below Grate Secondary Air Temperature	1460°F
Above Grate Secondary Air Temperature	1695°F
Product Discharge Temperature	250°F
East Cooler Temperature	480°F
North Cooler Temperature	120°F
West Cooler Temperature	110°F
Ball Mill Outlet Temperature	180°F
Burner Pipe Pressure	6.5 in WC
Cooler Pressure	11.25 in WC

Table II : Nelson Kilns Current Operating Conditions

6. LIMITATION OF LIABILITY AND CONSEQUENTIAL LOSSES

KFS limitation of liability shall not exceed the total contract value. KFS will not accept any claims for consequential losses howsoever arising.

7. EXCLUSIONS

The following items and services are excluded from the scope of supply of this quotation:

- off-loading at site
- burner refractory anchors, materials, and installation
- carriage rails and support steelwork
- modification to existing diesel oil system
- atomizing air compressor
- new BMS equipment or reprogramming of existing BMS
- coal mill air flex hose
- interconnecting piping, ducting and wiring
- analogue control system and HMIs
- installation at site
- any design, engineering, equipment supply, or site services not specifically mentioned in this proposal

For and on behalf of
Kiln Flame Systems Ltd

Cliff Rennie
CEO & Director

TECHNICAL APPENDIX
PROPOSAL FOR LOW NOx BURNER
K2 NELSON PLANT

A1 INTRODUCTION

LNA operates two rotary kilns at Nelson Plant, AZ.

K2 is a 1,200 stpd KVS preheater kiln. No.2 diesel oil is used as the start-up fuel.

The kiln is direct-fired via a ball mill and straight-pipe burner and currently use a blend of 25% coal and 75% petcoke. Kiln warm-up is achieved with several separate, manually inserted and controlled diesel lances.

KFS have been requested to provide a proposal for a low NOx burner to reduce emissions at source, with further reduction provided by downstream SNCR, as required to meet the new State imposed NOx limit.

KFS propose the DFN Low NOx burner technology which has been installed successfully in many rotary lime kilns in North America.

A2 PROPOSED SCOPE OF SUPPLY

A2.1 Burner System Engineering and Modeling

A2.1.1 Data Review (COMPLETED)

Current kiln process data has been provided by LNA in order to define an agreed baseline set of data for use in the modeling phase.

KFS will undertake additional site survey activities to confirm previously collected data.

A2.1.2 Aerodynamic and Combustion Modeling (COMPLETED)

This involves modeling of the kiln to derive combustion, process and NOx data. The modeling will be used confirm the details of the proposed burner design.

The design of the model and all modeling activities will be based on agreed process data and detailed kiln/hood drawings provided by LNA.

For the LNA Nelson mathematical and CFD modeling techniques will be used, as applicable and appropriate.

KFS mathematical modeling of the combustion and heat transfer in the kiln will be undertaken. This is based on the air/fuel mixing regimes to determine the heat flux and heat transfer to the product in the kiln. The mathematical modeling will take into account the effect of the fuel burnout and heat transfer characteristics of the specified fuels.

CFD modeling will be used to provide additional combustion and process data that is not easily ascertained from traditional modeling, such as NOx emissions and flame stand-off. KFS experience of combustion and kiln operation combined with its physical and mathematical techniques used on over 250 kilns projects provide an exceptional ability to interpret and validate data obtained from the CFD modeling.

Modeling activities will include, as appropriate:

- KFS mathematical modeling
- CFD modeling:
  - set up model grid
  - prepare input/output files
  - computer run time and supervision

Deliverables will include:

- confirm basic design parameters for the new burner:
  - process parameters and mechanical configuration including kiln discharge cone/dam
  - predicted NOx emissions
  - modeling to provide the basic specifications for the new burner for subsequent

detailed engineering design and supply

- summary report of principal results (ALREADY ISSUED):
  - data for principal modeling runs for each case
  - conclusions and recommendations

A2.1.3 Engineering and Documentation

KFS equipment prices include all necessary engineering for supply of the dual-fuel DFN burner and associated equipment items. All systems and equipment will be in accordance with American Standards and the specified site conditions, preferred vendors, and specifications, as applicable and appropriate.

KFS to provide design and engineering requirements as outlined below. Documentation will be provided in PDF electronic format. Documents will be provided with Imperial and metric engineering units (NB: where shown, metric dimensions will be used for equipment drawings with equivalent Imperial value indicated in decimal format).

Engineering documentation includes:

- System design:
  - P&ID for burner system
  - combustion system service requirements, as applicable (diesel and atomizing air, burner primary and cooling air flowrates, air cylinders, flame scanner purge air)

- DFN burner:
  - burner GA drawing including mounting details
  - HE ignitor GA drawings

- Burner mounting and installation:
  - GA layout drawing
  - burner carriage GA drawing

- Clean primary air fan:
  - GA drawing
  - fan curves
  - motor datasheet
  - flowmeter datasheet

- Installation, operation and maintenance manual:
  - specific sections for KFS designed equipment
  - vendor standard documentation for all sub-vendor items
  - spare parts list

A2.2 KFS Low NOx DFN Nozzle with Integrated KFS HSB Diesel Warm-up Burner

Based on the results of the modeling KFS to design and supply its proprietary DFN burner. The burner is designed for coal/petcoke only firing.

Deliverables to include:

- fully pre-fabricated DFN in carbon/wear-resistant/stainless steels, as appropriate to final design
- design to allow for simplicity of installation to the coal mill air ducting (to be discussed during the mechanical design phase)
- HSB-L warm-up burner integrated into main burner refractory lining (Figure I):
    - outer pipe fabricated in sch40S 304L stainless steel
    - oil gun guide tube fabricated in carbon steel with 304L stainless steel end section
    - oil gun fabricated in carbon steel with CM atomizer assembly manufactured in 304L stainless steel, and quick connect coupling for oil and atomizing air (Figure II and Figure III)
    - aerodynamic swirler to provide flame stability fabricated in 304L stainless steel
    - high energy (HE) igniter with pneumatic retraction system with limit switches
    - air inlet flange in carbon steel
    - welded construction with flanged assembly allowing for dismantling
    - carbon steel external surfaces primer and finish painted
    - set of 8ft long flex hoses for oil, atomizing air (rubber with stainless braid), and primary air (rubber only)

The burner outer air pipes will require fitting with anchors and refractory lining with minimum 3in thick castable material. Anchor and refractory supply and installation by others.

KFS will supply the required flex hoses for connection of services to the diesel warm-up burner. The hoses will be stainless steel braided with length 4-6 ft, as appropriate:

- diesel oil
- atomizing air
- swirl air
- burner central purge air
- fiber optic flame scanner purge air
- HE ignitor retraction cylinder air
- oil gun retraction cylinder air

A2.2.1 Hood-Mounting Chassis

Supply of a pre-assembled hood-mounting chassis for burner support. The sub-frame includes 4 ratchet turnbuckles for manual adjustment of burner orientation. The sub-frame is fabricated in carbon steel with primer and finish painted surfaces.

KFS will complete structural calculation and provide drawings for any required strengthening of the firing hood front plate and fixing of the sub-frame.

A2.2.2 Warm-up Burner Primary Air Fan and Associated Items

In the event that any existing fan cannot be reused, primary air fan system consisting of the following equipment items:

- fan set of centrifugal type complete with base-frame mounted fan and 3600rpm 460V/60Hz 15hp TEFC motor with direct drive and guard, all with vendor standard surface finish
- VFD (AB or similar) variable speed drive unit protected to NEMA 1 for installation in clean MCC room
- low pressure switch (PSL) for primary air flow proving; switch suitable for 120VAC and protected to minimum NEMA 4

The primary air fan could also be used for burner emergency cooling air. This function should be assured by connection of the fan to the plant emergency power system.

A2.3 Assistance During Commissioning

At Lhoist request, KFS will provide a combustion engineer at site to supervise and commission the KFS burner and associated equipment. The KFS attendance at site includes training as needed. Site assistance is charged at prevailing KFS day rates plus flight costs.

Activities include:
- verification of installation of KFS supplied equipment
- operator training
- assistance during cold and hot commissioning
- optimization of burner operation

A2.4 Spare Parts

Table III indicates the preliminary recommended spares requirement for commissioning and 2 years of operation. Full details will be provided on completion of engineering and final sub-supplier selection.

Equipment	Part #	Description	Qty (Comm.)	Qty (2 yr)	Price Each, $	Total Price, $
Oil Gun	S1979	Atomiser outer tip	1	1	1,301.00	2,602.00
	S1978	Atomiser inner tip	1	1	2,097.00	4,194.00
	S4356	Set atomising dealing washers	1	6	104.00	728.00
	100000370	Air cylinder repair kit		1	44.00	44.00
HE Ignitor	02000006	Ignitor tip	1	1	632.00	1,264.00
	07070112X	Ignitor power pack		1	3,527.00	3,527.00
	100000370	Air cylinder seal kit		1	44.00	44.00
					Total	**12,403.00**

Table III : Spare Parts List

Burner Front

Burner Rear

Figure I : KFS HSB Oil-Fired Warm-up Burner (HSB-L)

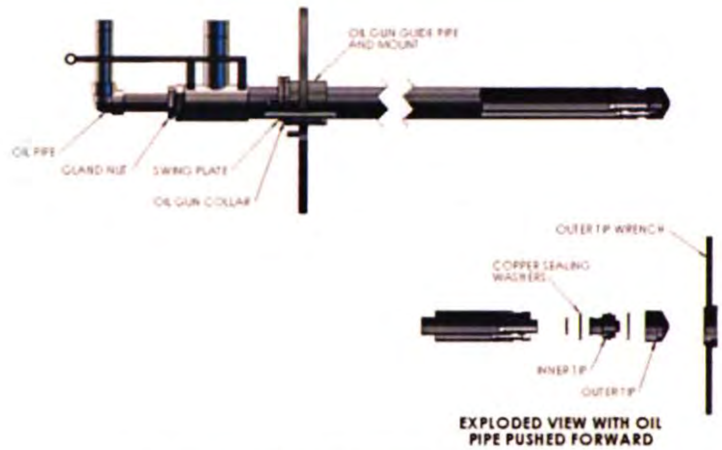

Figure II : KFS CM™ Oil Gun Assembly

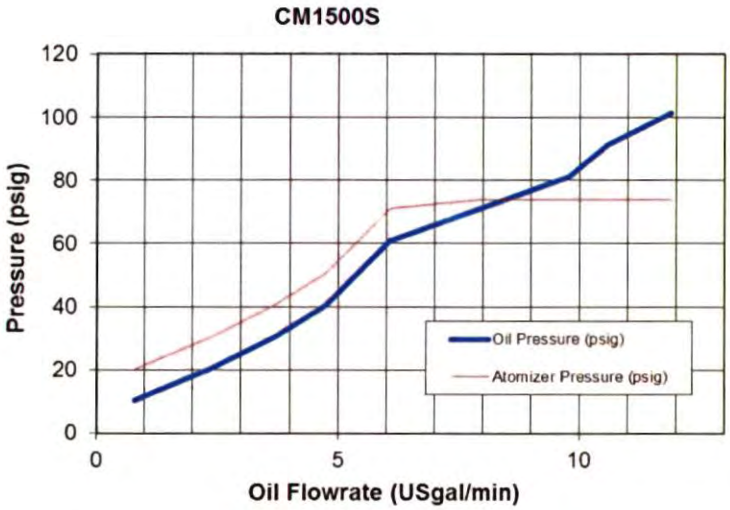

Figure III : CM 1500S Atomizer Performance Curve

APEX KILN 3 BURNER PRE-COMMISSIONING COST PROPOSAL

STRICTLY CONFIDENTIAL

Francisco Rodriguez
Sr. Project Manager
Lhoist North America
3700 Hulen St.
Fort Worth
TX 76102

LNA Ref: Product Supply Agreement dated 31-Mar-16

KFS Ref: E7178 Rev 2

Date: 3-Jul-19

PROPOSAL FOR BMS SYSTEM PRE-COMMISSIONING
APEX KILN 3

Dear Francisco,

Further to recent correspondence with Issam Tiani, I am pleased to provide the attached KFS revised proposal for pre-commissioning services for the Apex K3 BMS system based on your comments. This proposal has been expanded at Issam's request to include optional commissioning assistance for the DFN burner.

This proposal is provided under the auspices of LNA/KFS Product Supply Agreement dated 31-Mar-16.

I trust the proposal meets your requirements. Please do not hesitate to contact me if you need further information or clarification.

Yours sincerely

Bob Burn
Project Engineer

STRICTLY CONFIDENTIAL

PROPOSAL

Francisco Rodriguez
Sr. Project Manager
Lhoist North America
3700 Hulen St.
Fort Worth
TX 76102

LNA Ref: Product Supply Agreement dated 31-Mar-16

KFS Ref: E7178 Rev 1

Date: 13 June 2019

PROPOSAL FOR BMS SYSTEM PRE-COMMISSIONING
APEX KILN 3

1. INTRODUCTION

This proposal covers the scope of the Kiln Flame Systems (KFS) activities to carry out pre-commissioning of the Kiln 3 BMS system at Lhoist, Apex plant.

The scope of work is to be governed under the Agreement signed between Lhoist North America and Kiln Flame Systems dated 31-Mar-16, without exception.

2. SCOPE OF SUPPLY AND PRICES

To provide KFS and specialist sub-supplier engineers to assist with cold commissioning for the new BMS installed on Apex K3. The proposed scope of activities includes:

- Complete I/O check out for the valve train and all available new installed equipment. Note that the ID fan and hood pressure signals will still be wired to the kiln PLC so cannot be checked at this stage.
- Testing of the PA fan and regen blower and associated pressure switches.
- Matrix programmer to work with an LNA engineer on HMI development
- Optional commissioning assistance for DFN burner

Hot commissioning is not included within this scope of work. This will be carried out at a later date.

Pricing is based on site services rates and costs shown in the BMS Agreement:

- $1,650 per day (for each engineer, for 12 hr site days and travel days)
- over time $160 per hr (above 12 hrs)
- rate includes costs for accommodation and car rental
- flights charged at cost

A commissioning report will be provided which documents travel and site days plus any overtime. This will be used as the basis for invoicing.

The agreed provisional attendance at site is as shown in the table below.

		Controls Engineer	System Engineer	Kiln Engineer (Optional)
Monday, 29-Jul-19	HMI and Kiln PLC integration support BMS I/O testing	1	1	
Tuesday 30-Jul-19	BMS I/O testing Equipment and device commissioning	1	1	
Wednesday 31-Jul-19	Equipment and device commissioning DFN Commissioning assistance	1	1	1
Thursday 01-Aug-19	Kiln restart for testing BMS Functional Testing (<1400F) >1400F testing & post start-up support	1	1	1
Friday 02-Aug-19	>1400F testing & post start-up support DFN Commissioning assistance	1	1	1
Saturday 03-Aug-19	DFN Commissioning assistance			1
		5	**5**	**4**

Item Description	Price, US$
BMS start up and commissioning Travel and Site Attendance (Preliminary Total 14 days including travel)	23,100
Estimated Flight Costs	3,000

Item Description	Price, US$
Optional DFN Commissioning assistance Travel and Site Attendance (Preliminary Total 6 days including travel)	9,900

3. TERMS AND CONDITIONS

This proposal and any ensuing contract is subject to the standard Kiln Flame Systems Ltd Terms and Conditions of Sale unless otherwise agreed in writing except for the terms and conditions outlined in Sections 4.0 of this quotation.

SPECIAL CONDITIONS OF SALE

3.1 Price Basis

Prices are in US dollars and exclude any applicable taxes or duties and will be invoiced based on actual cost (airfares) and time recorded on site.

3.2 Validity

This proposal is valid for a period of 60 days from the date of issue.

3.3 Delivery

As stated in the schedule in section 2 (above) and attached BMS commissioning schedule.

3.4 Terms of Payment

KFS will request all financial transactions to be by electronic bank transfer net 30 days of invoice date. 100% on completion of site visit and submission of report

4. LIMITATION OF LIABILITY AND CONSEQUENTIAL LOSSES

KFS limitation of liability shall not exceed the total contract value. KFS will not accept any claims for consequential losses howsoever arising.

5. EXCLUSIONS

The following items and services are excluded from the scope of supply of this proposal:

- any time for burner assessment/adjustment
- any design, engineering, equipment supply, or site installation services not specifically mentioned in this proposal

For and on behalf of
Kiln Flame Systems Ltd

Bob Burn
Project Engineer

FORM OF PROPOSAL

RFQ. APX KB1902 Rev. 0
K3 BURNER/BMS PROJECT - EQUIPMENT INSTALLATION

Please return the following pages with your proposal. Supplementary information detailing the proposal may be supplied as required on additional attachment/pages. The Full Proposal will be e-mailed to:

Lhoist North America

Attn: Ben Boutaleb

Ben.Boutaleb@lhoist.com

ITEM	QTY	RFQ. APX KB1902 Rev. 0 K3 BURNER/BMS PROJECT - EQUIPMENT INSTALLATION DESCRIPTION	UNIT COST (US Dollars	TOTAL COST (US Dollars)	LEAD TIME (Wks)
		MATERIAL SUPPLY			
1	**Various**	Solids Fuel Piping materials **16" and 18" piping, fittings and supports.**	10600.00	10600	1-2 week
2	**Various**	Miscellaneous supplies and consumables to include. **Welding needs, miscellaneous nuts/bolts, lubricants, paint, office needs, water, portable toilets, lighting, fans, pumps, hoists, anchors, ladders**	24150.00	24150	1 week
3	**Various**	Miscellaneous Safety Supplies to Include: **Personal Protection Equipment, extinguishers, harness, lanyards, ventilation fans.**	1950	1950	N/A
		SUBTOTAL MATERIAL SUPPLY FIRM PRICE FOR (Items 1-3)	36,700.00		

		EQUIPMENT RENTAL MATERIAL SUPPLY			
1	**Various**	Miscellaneous Small Tools and Equipment to include. **Welding machines, fork truck, hand tools, generators.**	54850	54850	N/A
2	**Various**	**Crane Requirements.**	33150	33150	1 Week
		SUBTOTAL EQUIPMENT SUPPLY FIRM PRICE FOR (Items 1-2)	88000		

		CONSTRUCTION / INSTALLATION			
1	Various	Demolition of existing burner, support structure, ignitor system and solids fuel piping as required.	21800	21800	1 week
2	Various	Installation of Hood Mounted support Chassis, burner and solids fuel transition piece (supplied by others).	10770	10770	3 days
3	Various	Installation of solids fuel piping and supports (supplied by contractor).	44750	44750	2 weeks
4	1	Placement, anchor and tie in skid mounted valve addition	5500	5500	2 days
5	1	Regen Blower and related accessories.	5500	5500	2 days
6	1	Miscellaneous gas piping and ductwork.	43150	43150	2 week
7	1	Repair of siding where necessary.	2750	2750	1 day
8	1	Construction/Supervision Included	28650	28650	175
9	1	Startup Costs Included	12000	12000	200
		SUBTOTAL CONSTRUCTION FIRM PRICE FOR (Items 1-9)		174,870	

SUMMARY OF COSTS	
SUBTOTAL MATERIAL FIRM PRICE FOR (Items 1-3	36,700
SUBTOTAL EQUIPMENT FIRM PRICE FOR (Items 1-2)	88,000
SUBTOTAL CONSTRUCTION FIRM PRICE FOR (Items 1-9)	174870
TOTAL PROPOSAL FIRM PRICE	299,570.00

1.1. COMPLIANCE WITH GENERAL TERMS AND CONDITIONS:

The Bidder agrees that, if awarded an Order, he will accept the General Terms and Conditions attached to this RFQ and in the subsequent Agreement. Special Conditions, as defined and determined by the Buyer, may also be incorporated into a subsequent Agreement. Any exceptions taken by Bidder will be reviewed in the Bid Evaluation and may be cause for rejection of Bidder's Proposal.

If the Bidder takes exceptions, differences shall be itemized. No other General Terms or Conditions shall be binding upon the Buyer unless accepted by the Buyer and included in the Agreement.

☒ No exceptions taken

☐ Exceptions noted below

Note: State exceptions on a separate attachment.

1.2. COMPLIANCE WITH DATA SHEETS:

The Bidder has reviewed and understands the specifications contained in this RFQ and has verified his capability and willingness to furnish these items to conform to the requirements if awarded an Agreement in accordance with terms of this RFQ. If the Bidder's Proposal differs from these specifications and General Terms and Conditions in any way, the differences must be itemized.

☒ No exceptions taken

☐ Exceptions noted below

Note: State exceptions on a separate attachment.

1.3. BIDDER INFORMATION:

Bidder shall provide the following information about its organization that if successful will receive Orders for this requirement:

Prime Bidder Name: Ken Duren & Mike Honsinger

Proposal/Quote Number: 175900

Mailing Address: 7360 Eastgate Rd., Suite 100, Hendeson, NV 89011

Telephone No: 7026322988 Facsimile No: 7025587780

Email Address: ken.duren@twimail.com; mike.honsinger@twimail.com Dun & Bradstreet No: 112737127

1.4. DECLARATION OF BIDDER:

The undersigned Bidder certifies that it has examined and is familiar with the RFQ and its attachments, that it has confirmed all figures shown and understands that the Buyer will not be responsible for any errors or omissions made by the Bidder in preparing the Bid.

The Bidder's offer and the Bidder's equipment and/or materials are in strict conformance with the Buyer's requirements, and General Terms and Conditions as set forth in the RFQ. If there is any variance from the Buyer's requirements, the Bidder has itemized all variances elsewhere in this document or in attachment hereto.

This Offer is binding for acceptance within Ninety (90) days from the date below, or any additional period mutually agreed between the Buyer and the Bidder. The conditions of performance of any Award will be in accordance with the Agreement issued by the Buyer.

The undersigned is an Officer of the Bidder or an Authorized Representative of the Bidder, with the authority to make binding on Bidder, any quotations or contractual commitment as a result of the Bidder's Proposal.

Date: April 4, 2019 Company Name: TOTAL-WESTERN, INC.

Name of Bidder: Ken Duren Mike Honsinger

Signature:

Lhoist North America

12101 Las Vegas Blvd. North

Las Vegas, NV. 89036

CONTRACTOR SAFETY INFORMATION REQUEST

NAME OF COMPANY: Total-Western, Inc.

CONTACT PHONE NUMBER(S): 7026322988

ADDRESS: 7360 Eastgate Rd., Suite 100

CITY, STATE & ZIP: Henderson, NV 89011

MSHA Contractor ID: M203

Contractors: This contract has been identified as "High Safety Risk". As such, LNA requests some basic safety performance information. This information will be reviewed carefully as part of the bid evaluation. Please complete item 1 and submit with your bid proposal.

1. Provide the following information for the last three years that your company has been in operation. Include data for the years your company may have operated under a different name.

Year:	2015	2016	2017
Total Recordable Injury Rate (TRIR)*			
EMR**	.57	.52	.57
<u>OSHA sites</u> – *Any Serious, Willful, or Repeat Violations* <u>MSHA sites</u> – *Any Citations or Orders written as a result of unwarrantable failure or knowing/willful acts, as defined in Section 104(d) or 104(e)****	0	0	0

*TRIR – Reportable Incidents/200,000 work hours

** EMR - Workers' Compensation Experience Modification Rate

***Citations - Note the federal standard and what degree of severity it was written as; citations not written as described above do not need to be communicated to LNA.

12101 Las Vegas Blvd. North

Las Vegas, NV. 89036

Please note that after contract award, but prior to starting work on Lhoist property, you are required to provide the following documents to LNA. These items will be reviewed at the project Kick-off Meeting:

- □ Safety Training Plan – Provide required MSHA (Part 46 and/or Part 48A/B) training plan.
- □ Employee Training Documentation (see *EH&S Training* for required documented training).
- □ Written Safety Program (contractor company policies and procedures) if requested.

I certify that the above information is true and accurate, and we will comply with the Lhoist requirements as noted above.

Printed Name: Mike Honsinger

Signature: MJ Honsinger

Title: Business Development

Date: 4/4/19

Total-American
Total-Western Spectra

Corporate Safety Data Information

Through 12/31/2018

Experience Modification Rate (EMR)	2014	2015	2016	2017	2018
EMR	0.69	0.57	0.52	0.57	0.66

OSHA Statistics	2014	2015	2016	2017	2018
Lost Time Incident Rate	0.1	0.0	0.0	0.0	0.0
Recordable Incident Rate	0.2	0.3	0.4	0.4	0.3
DART Rate	0.19	0.00	0.37	0.22	0.10

OSHA 300 Log	2014	2015	2016	2017	2018
Number of fatalities	0	0	0	0	0
Cases involving lost or restricted workdays	1	0	3	2	1
Cases involving lost workdays	1	0	0	0	0
Number of lost workdays	10	0	0	0	0
Number of restricted workdays	22	0	87	14	15
Number of medical only cases	1	3	1	2	2
Total number of recordable cases	3	3	4	4	3
First Aid Cases	38	22	14	34	30

Total Employee Hours Worked	2014	2015	2016	2017	2018
	2,158,007	1,893,257	1,608,466	1,828,907	1,931,234
Average Number of Employees	810	680	714	935	972

Safety Information

- Total Recordable Incident Rate (TRIR) – 2018 – 0.3
- Experience Modification Rate (EMR) – 2018 – 0.66
- ISNetworld – Incident Investigation and Reporting – 100%
  Injury / Illness Recordkeeping – 100%
  IIPP Policy is Available
- Avetta – 100% Compliant

LHOIST NELSON - COLONIAL CHEMICAL UREA QUOTE

COLONIAL
CHEMICAL
COMPANY
A UNIT OF THE ESS GROUP, INC.

December 31, 2019

Beth White
Spot Buyer – West and Texas Regions
Lhoist North America
Nelson Location
Mile Post 112, US HWY 66,
Peach Springs, Arizona, 86434

[redacted]

Thank you for your business.

Regards,

David DiMeo
Colonial Chemical Company
484-534-9190

LHOIST NELSON - SNCR SYSTEM BID COMPARISON

LHOIST APEX - KILN 4 SULFUR BALANCE

[redacted]

BART FIVE FACTOR ANALYSIS

Lhoist North America > Nelson Lime Plant

Prepared By:

TRINITY CONSULTANTS
9777 Ridge Drive, Suite 380
Lenexa, Kansas 66216
(913) 894-4500

In Conjunction with:

LHOIST NORTH AMERICA OF ARIZONA, INC.
P.O. Box 370
Peach Springs, Arizona 86434
(928) 769-2271

August 2013

Project 131701.0061

Lhoist

Trinity Consultants

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1. EXECUTIVE SUMMARY

This report documents the determination of the Best Available Retrofit Technology (BART) for the two kilns (Kiln 1 and Kiln 2) at the Lhoist North America of Arizona, Inc. (LNA) Nelson Lime Plant located near Peach Springs, Arizona. The kilns currently do not have add-on control for nitrogen oxides (NO_x) or sulfur dioxide (SO_2), but both kilns have baghouses for control of particulate matter (PM).

Based on the criteria detailed in the Environmental Protection Agency's (EPA's) 2005 BART Rule, Kiln 1 and Kiln 2 have been identified by LNA as being BART-eligible. EPA disapproved LNA's and Arizona's "not subject to BART" demonstration in a final rule dated July 30, 2013 (Federal Register / Vol. 78, No. 146 / Tuesday, July 30, 2013). Accordingly, LNA submits the following BART demonstration to EPA in preparation for the Federal Implementation Plan process referenced in the final rule disapproving the not subject to BART demonstration.

Trinity used the EPA's BART guidelines in Title 40 of the Code of Federal Regulations (40 CFR) Part 51[1] to determine BART for the lime kilns. Trinity conducted a five-step analysis to determine BART for SO_2 and NO_x that included the following:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and documenting the results; and
5. Evaluating visibility impacts.

The BART analysis concluded that the operation of selective noncatalytic reduction (SNCR) constitutes BART for NO_x for both Kiln 1 and Kiln 2. The proposed BART emission limit for NO_x for Kiln 1 is 3.65 lbs NO_x/ton lime on a rolling 30-day average, as demonstrated through the use of a Continuous Emissions Monitoring System (CEMS), and the proposed BART emission limit for NO_x for Kiln 2 is 2.13 lbs NO_x/ ton lime on a rolling 30-day average, as demonstrated through the use of a CEMS. The proposed NO_x emission limits reflect a 50% reduction from the NO_x baseline emission levels.

The BART analysis concluded that the use of a lower sulfur fuel blend constitutes BART for SO_2. Neither wet nor semi-dry scrubbing are feasible due to limited water availability in comparison to the water demands of the technologies. Consideration was given to using Dry Sorbent Injection (DSI), but the cost of the annual sorbent usage is very high and results in a cost effectiveness for DSI based on the use of either sodium bicarbonate or Sorbacal® SPS that is over \$5,000/ton SO_2 and over \$50 million/Δdv. The proposed BART emission limit for SO_2 for Kiln 1 is 9.32 lbs SO_2/ton lime on a rolling 30-day average, as demonstrated through the use of a CEMS, and the proposed BART emission limit for SO_2 for Kiln 2 is 9.73 lbs SO_2/ton lime on a rolling 30-day average, as demonstrated through the use of a CEMS. The proposed SO_2 emission limits reflect a 23.3% reduction from the SO_2 baseline emission levels.

The BART analysis concluded that the existing baghouses constitute BART for particulate matter (PM) because they are the most effective available control. The proposed BART limit for PM is the current Maximum Achievable Control Technology (MACT) limit established in 40 CFR Part 63 of 0.12 lb/ton stone feed.

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[1] The BART guidelines were published as amendments to the EPA's Regional Haze Rule (RHR) in 40 CFR Part 51, Section 308 on July 6, 2005 and are codified in Appendix Y. The Guidelines are binding solely for power plants of 750 MW installed capacity, *see* 42 U.S.C. § 7491(b)(2), but are useful guidance for applying BART to all plants, *see* BART Guidelines, § I.F.1.

2. INTRODUCTION AND BACKGROUND

On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to improve visibility 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 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that a source is reasonably anticipated to contribute to visibility impairment if the 98th percentile visibility impacts from the source are greater than 0.5 delta deciviews (Δdv) when compared against a natural background. Air quality modeling is the tool that is used to determine a source's visibility impacts.

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

"...an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by...[a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonable be anticipated to result from the use of such technology."

Specifically, the BART rule states that a BART determination should address the following five statutory factors:

1. Existing controls,
2. Cost of controls,
3. Energy and non-air quality environmental impacts,
4. Remaining useful life of the source, and
5. Degree of visibility improvement as a result of controls

Further, the BART rule indicates that the five basic steps in a BART analysis can be summarized as follows:

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

A BART determination should be made for each visibility affecting pollutant (VAP) by following the five steps listed above for each VAP.

The Nelson lime kilns meet the three BART-eligibility criteria described above. Further, EPA has ruled that both Kiln 1 and Kiln 2 are subject to BART (Federal Register / Vol. 78, No. 146 / Tuesday, July 30, 2013).[2] Details of the baseline emissions used to conduct the analysis presented herein can be found in Section 4. The VAPs emitted by the kilns include NO_x, SO_2, and PM of various forms (filterable coarse particulate matter [PM_c], filterable fine particulate matter [PM_f], elemental carbon [EC], inorganic condensable particulate matter [IOR CPM] as sulfates [SO_4], and organic condensable particulate matter [OR CPM] also referred to as secondary organic aerosols [SOA]). The BART determinations for SO_2, NO_x, and PM can be found in Sections 5, 6, and 7 of this report, respectively.

[2] LNA and the Arizona Department of Environmental Quality had initially concluded the total dv impact was less than 0.5 dv. In its final rule, EPA disapproved the three year 98th percentile approach and concluded that the Nelson Plant's impact is greater than 0.5 dv. For purposes of this analysis, LNA is following the EPA approach, although LNA reserves the right to challenge EPA's approach.

3. MODELING METHODOLOGIES AND PROCEDURES

This section summarizes the dispersion modeling methodologies and procedures applied in the BART analysis. All dispersion modeling has been conducted using the CALPUFF modeling system, consisting of the CALPUFF dispersion model, the CALMET meteorological data processor, and the CALPOST post-processing program. The specific program versions that were relied upon in the analysis match the program versions relied upon by EPA's contractor, the University of North Carolina at Chapel Hill and ICF International (UNC/ICF), in the BART analyses that they prepared for select sources, including the Nelson Plant.

CALPUFF is a multi-layer, multi-species, non-steady-state puff dispersion model, which can simulate the effects of time and space varying meteorological conditions on pollutant transport, transformation, and removal. CALPUFF uses three-dimensional meteorological fields developed by the CALMET model. In addition to meteorological data, several other input files are used by the CALPUFF model to specify source and receptor parameters. The selection and control of CALPUFF options are determined by user-specific inputs contained in the control file. This file contains all of the necessary information to define a model run (e.g., starting date, run length, grid specifications, technical options, output options). CALPOST processes concentration, deposition, and visibility impacts based on pollutant specific concentrations predicted by CALPUFF.

3.1. CALMET

The CALMET data sets relied upon in the analysis are the CALMET data sets that were provided by Mr. Scott Bohning of EPA Region 9 to Mr. Jonathon Hill of Trinity Consultants. The data sets were prepared by ENSR Corporation, the contractor responsible for the BART analysis of the Salt River Project (SRP) – Navajo Generating Station. The data sets cover 2001, 2002, and 2003. No changes were made to the data sets as part of conducting the BART analysis. These are the same data sets that were relied upon in the UNC/ICF BART analyses.

3.2. CALPUFF

The CALPUFF data and parameter settings relied upon in the analysis are the same data and parameter settings that were relied upon in the UNC/ICF BART analyses.

The Kiln 1 and Kiln 2 emission rates input to the CALPUFF model are discussed elsewhere in this report. Table 3-1 provides a summary of the stack parameters other than emission rates that were relied upon in the BART analysis. The temperatures and flow rates summarized in Table 3-1 are the average temperatures and flow rates determined from data collected during emissions testing on the kilns conducted in March 2013, as further described in Section 4 of this report.

Table 3-1. Summary of Kiln 1 and Kiln 2 Stack Parameters

Kiln	Stack Height (ft)	Stack Height (m)	Stack Diameter (ft)	Stack Diameter (m)	Exhaust Temp (F)	Exhaust Temp (K)	Exhaust Velocity (ft/s)	Exhaust Velocity (m/s)
Kiln 1	140	42.67	10	3.05	405	480.37	30.33	9.25
Kiln 2	141	42.98	10	3.05	434	496.48	35.12	10.71

Prior to processing the CALPUFF output data in CALPOST, the data were processed using POSTUTIL. POSTUTIL was used to adjust the concentrations output by CALPUFF to repartition the HNO_3 between the gas and particle phases. The POSTUTIL settings relied upon in the analysis are the same settings that were relied upon in the UNC/ICF BART analyses.

3.3. CALPOST

The CALPOST visibility processing completed for the BART analysis is based on the October 2010 guidance from the Federal Land Managers Air Quality Related Values Workgroup (FLAG).[3]

Visibility impairment is quantified using the light extinction coefficient (b_{ext}), which is expressed in terms of the haze index expressed in deciviews (dv). The haze index (*HI*) is calculated as follows:

$$HI(\mathrm{dv}) = 10\ln\left(\frac{b_{ext}}{10}\right)$$

The impact of a source is determined by comparing the *HI* attributable to a source relative to estimated natural background conditions. The change in the haze index, in deciviews, also referred to as "delta dv," or Δdv, based on the source and background light extinction is based on the following equation:

$$\Delta \mathrm{dv} = 10 * \ln\left[\frac{\mathrm{b}_{\mathrm{ext,\ background}} + \mathrm{b}_{\mathrm{ext,\ source}}}{\mathrm{b}_{\mathrm{ext,\ background}}}\right]$$

The Interagency Monitoring of Protected Visual Environments (IMPROVE) workgroup adopted an equation for predicting light extinction as part of the 2010 FLAG guidance (often referred to as the new IMPROVE equation). The new IMPROVE equation is as follows:

$$b_{ext} = \begin{array}{l} 2.2 f_S(RH)[\mathrm{NH_4(SO_4)_2}]_{\mathrm{Small}} + 4.8 f_L(RH)[\mathrm{NH_4(SO_4)_2}]_{\mathrm{Large}} + \\ 2.4 f_S(RH)[\mathrm{NH_4NO_3}]_{\mathrm{Small}} + 5.1 f_L(RH)[\mathrm{NH_4NO_3}]_{\mathrm{Large}} + \\ 2.8[\mathrm{OC}]_{\mathrm{Small}} + 6.1[\mathrm{OC}]_{\mathrm{Large}} + 10[\mathrm{EC}] + 1[\mathrm{PMF}] + 0.6[\mathrm{PMC}] + \\ 1.4 f_{SS}(RH)[\mathrm{Sea\ Salt}] + b_{\mathrm{Site-specific\ Rayleigh\ Scattering}} + 0.33[\mathrm{NO_2}] \end{array}$$

Visibility impairment predictions relied upon in this BART analysis used the equation shown above. The use of this equation is referred to as "Method 8" in the CALPOST control file. The use of Method 8 requires that one of five different "modes" be selected. The modes specify the approach for addressing the growth of hygroscopic particles due to moisture in the atmosphere. "Mode 5" has been used in this BART analysis.

CALPOST Method 8, Mode 5 requires the following:

- Annual average concentrations reflecting natural background for various particles and for sea salt
- Monthly Relative Humidity (RH) adjustment factors for large and small ammonium sulfates and nitrates and for sea salts
- Rayleigh scattering parameter corrected for site-specific elevation

Data for all of the variables associated with Method 8, Mode 5 were obtained from the 2010 FLAG guidance.

[3] The 2010 FLAG guidance makes technical revisions to the previous guidance issued in December 2000.

4. BASELINE EMISSIONS AND VISIBILITY IMPAIRMENT

This section summarizes the baseline emissions rates and the baseline visibility impairment.

4.1. NO_X AND SO_2 BASELINE EMISSION RATES

In the EPA's 2005 Regional Haze Rule BART Guidelines, EPA described baseline emissions as follows:

> *"The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period. When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice."*

Note that the baseline description provided above only addresses annual baseline emissions that are used to establish a benchmark for determining the tons reduced in the annual cost effectiveness analysis. Baseline emission rates are actually needed in several steps of the BART analysis. Baseline emission rates representing the maximum actual 24-hour emissions are needed to establish the baseline visibility impairment from which the visibility improvement can be evaluated in Step 5 of the BART analysis. Annual baseline emission rates are also needed as part of evaluating the annual tons reduced in the cost effectiveness analyses conducted in Step 4 of the BART analysis. Finally, baseline emission rates in lb/ton lime can be relevant for establishing limits and for comparing existing emission levels to controlled emission levels that can be achieved based on the application of certain control devices.

LNA's approach to establishing baseline emissions was to first establish baseline emission factors in lb/ton lime that represent realistic estimates of anticipated emissions and then to multiply the emission factors by the appropriate baseline production rates to get daily and annual emissions.

In preparation for conducting a five factor BART analysis, LNA reviewed the BART rule to understand the significance of the baseline emissions in the analysis. Since baseline emissions can serve as the basis for enforceable limits, LNA recognized the need to get a better understanding of the existing NO_x and SO_2 emissions for the two kilns based on current kiln operations. Consequently, LNA conducted SO_2 and NO_x Continuous Emission Monitoring System (CEMS) testing of both kilns from March 18th to March 23rd of 2013, representing 119 hours of data, then again from May 13th to May 18th of 2013, representing 108 hours of data, and then again from June 17th to June 22nd, representing 120 hours of data[4].

The average daily emission factors resulting from the 2013 CEMS testing are shown in Table 4-1 below.

[4] Of the 120 hours where SO_2 was measured on both kilns in June, some of the hours reflect hours where sorbent was injected into the kilns, as described in more detail in Appendix B.

Table 4-1. Summary of Daily Average Emission Factors from March, May and June 2013 CEMS Testing

Date	Kiln 1		Kiln 2	
	NO_x (lb/ton lime)	SO_2 (lb/ton lime)	NO_x (lb/ton lime)	SO_2 (lb/ton lime)
3/18/2013	5.35	6.70	3.60	8.50
3/19/2013	6.69	7.75	3.30	9.03
3/20/2013	5.69	6.96	3.22	8.74
3/21/2013	5.66	5.82	3.59	8.23
3/22/2013	5.48	6.07	3.50	6.98
3/23/2013	5.01	5.47	3.26	5.63
5/13/2013	6.27	9.33	3.43	10.54
5/14/2013	6.23	9.44	3.21	11.18
5/15/2013	5.92	9.78	2.84	11.29
5/16/2013	5.60	9.68	2.80	9.27
5/17/2013	6.16	6.75	3.08	7.87
5/18/2013	5.96	7.92	3.01	8.45
6/17/2013	6.72	8.62	3.83	8.57
6/18/2013	6.74	8.56	4.27	9.71
6/19/2013	6.47	9.37	4.11	9.81
6/20/2013	6.02	10.39	4.35	9.13
6/21/2013	6.64	10.31	5.42	8.72
6/22/2013	6.84	7.97	4.94	9.02
Max from Above	6.84	10.39	5.42	11.29

The 2013 emissions testing was conducted under conditions that LNA believes are representative of current conditions. The NO_x and SO_2 emission rates were highly variable, as shown by the data in Table 4-1. Since the duration of the testing was limited to less than 350 hours, it is extremely likely that the duration of the testing was not sufficient to capture the full range of the anticipated emissions variability. Since the definition of baseline emissions requires LNA to develop a realistic depiction of anticipated emissions, it is necessary to consider anticipated emissions variability in estimating baseline emissions. Consequently, LNA performed a statistical analysis of the 2013 CEMS data to develop emission factors that are representative of anticipated emissions.

Table 4-2 provides a summary of the statistical analysis conducted on the March, May, and June 2013 NO_x and SO_2 CEMS data sets.

Table 4-2. Summary of Hourly Emission Factors from March, May, and June 2013 CEMS Testing

	Kiln 1		Kiln 2	
	NO_x (lb/ton lime)	SO_2 (lb/ton lime)	NO_x (lb/ton lime)	SO_2 (lb/ton lime)
Summary of March, May and June Testing:				
Hourly Max	8.35	19.44	6.97	15.01
Hourly Avg	6.10	8.17	3.66	9.03
Hourly Std Dev	0.74	1.99	0.77	1.83
Avg + 1 Std Dev	6.84	10.16	4.43	10.86
Avg + 2 Std Dev	7.59	12.15	5.21	12.69
Summary of March Testing:				
Hourly Max	7.63	8.81	4.38	11.56
Hourly Avg	5.76	6.60	3.41	8.12
Hourly Std Dev	0.63	1.21	0.33	1.41
Avg + 1 Std Dev	6.39	7.81	3.74	9.54
Avg + 2 Std Dev	7.02	9.02	4.07	10.95
Summary of May Testing:				
Hourly Max	7.59	11.78	3.81	15.01
Hourly Avg	6.03	8.83	3.03	9.86
Hourly Std Dev	0.57	1.50	0.39	2.15
Avg + 1 Std Dev	6.60	10.33	3.42	12.01
Avg + 2 Std Dev	7.17	11.82	3.81	14.16
Summary of June Testing:				
Hourly Max	8.35	19.44	6.97	13.23
Hourly Avg	6.52	9.29	4.45	9.16
Hourly Std Dev	0.79	2.02	0.65	1.30
Avg + 1 Std Dev	7.31	11.31	5.10	10.47
Avg + 2 Std Dev	8.10	13.33	5.75	11.77

LNA considers the hourly average emission factors plus two standard deviations based on the March, May, and June 2013 testing, which is approximately equal to the 95% confidence interval, to represent anticipated emission levels based on the statistical analysis summarized in Table 4-2. With the exception of NO_x on Kiln 2, the emission factors calculated using this approach are higher than the maximum daily emission factors shown in Table 4-1. Thus, this approach accounts for the potential emissions variability going forward. While the hourly average emission factor plus two standard deviations for NO_x on Kiln 2 based on the March, May, and June 2013 testing of 5.21 lb/ton lime is not higher than the daily emission factor of 5.42 lb/ton lime shown in Table 4-2, LNA is proposing that any BART limit would be applicable on a 30-day rolling basis, and thus LNA believes 5.21 lb/ton lime represents an appropriate emission factor for purposes of this BART analysis.

Maximum Actual 24-Hour Emissions Rates:

The baseline maximum actual 24-hour emission rates were calculated by multiplying the hourly emission factors based on two standard deviations listed in Table 4-2 above by the highest daily production rate that occurred during the CEMS testing. The baseline daily emission rates and associated production levels are shown in Table 4-3.

Table 4-3. Summary of Daily NO_x and SO_2 Baseline Emissions

Parameter	Kiln 1	Kiln 2
NO_x Factor (lb/ton lime)*	7.59	5.21
SO_2 Factor (lb/ton lime)*	12.15	12.69
Max Daily Lime Production (tpd)**	866	1246
Baseline Daily NO_x Emissions (lb/day)	6,571	6,490
Baseline Daily SO_2 Emissions (lb/day)	10,526	15,808

* Factors from March, May and June 2013 CEMS testing.
** Maximum daily rates representing maximum rates that occurred during the March 2013 CEMS testing.

Annual Emission Rates:

The baseline annual emission rates were calculated by multiplying the hourly emission factors based on two standard deviations by the highest annual production rate that has occurred for each kiln from 2001 to 2012. The baseline annual emission rates and associated production levels are shown in Table 4-34.

Table 4-4. Summary of Annual NO_x and SO_2 Baseline Emissions

Parameter	Kiln 1	Kiln 2
NO_x Factor (lb/ton lime)*	7.59	5.21
SO_2 Factor (lb/ton lime)*	12.15	12.69
Annual Lime Production (tpy)**	258,508 (2010)	378,296 (2012)
Baseline Annual NO_x Emissions (tpy)	981	985
Baseline Annual SO_2 Emissions (tpy)	1,571	2,400

* Factors from March, May and June 2013 CEMS testing.
** The annual lime production represents the highest annual production rate for each kiln from2001 to 2012.

4.2. PM_{10} BASELINE EMISSION RATES

The PM baseline emission rates were calculated based on the National Park Service (NPS) "speciation workbook" for *Coal-fired Rotary Lime Kiln with Fabric Filter.* Filterable PM emission rates were input to the spreadsheet to get the total speciated PM emissions for each kiln. The filterable PM emission rates were calculated by multiplying kiln-specific PM filterable emission factors by the same daily and annual production rates that were relied upon to calculate NO_x and SO_2 baseline emissions. PM filterable emission factors were derived from stack testing conducted in 2009, 2010, and 2011. Specifically, emission factors were calculated based on the average PM emissions factors determined from testing conducted in 2009, 2010, and 2011 plus two standard deviations. The data relied upon to determine the filterable PM baseline emission rates are summarized in Table 4-5.

Table 4-5. Summary of Baseline PM Emissions Based on 2009, 2010, and 2011 Stack Tests

	Kiln 1 PM Filterable (lb/ton lime)	Kiln 2 PM Filterable (lb/ton lime)
2011 Tested 1-Hour Emission Factors	0.006	0.014
	0.003	0.011
	0.004	0.016
2010 Tested 1-Hour Emission Factors	0.011	0.017
	0.013	0.029
	0.010	0.019
2009 Tested 1-Hour Emission Factors	0.080	0.037
	0.039	0.017
	0.033	0.018
2008 Tested 1-Hour Emission Factors	0.021	0.030
	0.019	0.010
	0.018	0.043
2007 Tested 1-Hour Emission Factors	0.004	0.080
	0.006	0.063
	0.008	0.065
2006 Tested 1-Hour Emission Factors	0.059	0.084
	0.027	0.042
	0.023	0.042
2006-2011 Average	0.021	0.035
2006-2011 Std Dev	0.021	0.023
2006-2011 Avg + 2 Std Dev	0.063	0.082
Daily Production (tpd)	866	1,246
Annual Production (tpy)	258,508	378,296
Daily Emission Rate (lb/day)	54.17	102.55
Annual Emission Rate (tpy)	8.08	15.57

The daily filterable PM emission rates shown in Table 4-5 were used to estimate the total speciated PM emissions. The NPS workbook shows the following baseline distribution for the PM species:

- Total PM = Filterable PM/80.3%
- Coarse PM (PM_C) = 41% of Total PM
- Fine soil (modeled as PM_F) = 38% of Total PM
- Fine elemental carbon (modeled as EC) = 1% of Total PM

- Organic condensable PM (modeled as SOA) = 0% of Total PM
- Inorganic condensable PM (modeled as SO_4) = 20% of Total PM

The speciated PM emission rates shown in Table 4-6 are based on the filterable emission rates shown in Table 4-5 and the NPS workbook analysis. The emission rates shown in Table 4-6 represent the hourly equivalents of the daily emission rates.

Table 4-6. Summary of Speciated PM_{10} Emission Rates

	Total PM (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
Kiln 1	2.81	0.54	1.15	1.07	0.01	0.04
Kiln 2	5.32	1.03	2.18	2.02	0.03	0.08

4.3. BASELINE VISIBILITY IMPAIRMENT

Modeling was conducted following the methods summarized in Section 3 to estimate the baseline visibility impairment attributable to the Nelson lime kilns. The results of the baseline modeling are summarized in Table 4-7.

Table 4-7. Summary of Baseline Visibility Impairment Attributable to Kiln 1 and Kiln 2

Year	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	98th Percentile SO4 Δdv	98th Percentile NO3 Δdv	98th Percentile PM* Δdv	98th Percentile NO2 Δdv
Bryce Canyon NP							
2001	0.472	0.121	0	0.038	0.080	0.000	0.002
2002	0.291	0.131	0	0.040	0.088	0.000	0.003
2003	0.446	0.182	0	0.178	0.004	0.001	0.000
Grand Canyon NP							
2001	1.604	0.849	28	0.415	0.425	0.003	0.007
2002	2.684	0.996	36	0.248	0.627	0.010	0.112
2003	2.068	1.586	47	0.598	0.831	0.016	0.141
Joshua Tree NP							
2001	0.462	0.201	0	0.118	0.080	0.001	0.002
2002	0.330	0.174	0	0.170	0.004	0.000	0.000
2003	0.266	0.130	0	0.128	0.001	0.001	0.000
Mazatzal Wilderness							
2001	0.685	0.088	1	0.080	0.006	0.001	0.002
2002	0.292	0.140	0	0.096	0.042	0.001	0.001
2003	0.808	0.128	1	0.101	0.026	0.000	0.000
Pine Mountain Wilderness							
2001	1.001	0.088	1	0.065	0.022	0.001	0.001
2002	0.329	0.150	0	0.108	0.040	0.001	0.001
2003	0.867	0.122	2	0.064	0.057	0.000	0.000
Sierra Ancha Wilderness							
2001	0.328	0.063	0	0.033	0.029	0.000	0.001
2002	0.196	0.101	0	0.045	0.055	0.000	0.000
2003	0.278	0.102	0	0.102	0.000	0.000	0.000
Superstition Wilderness							
2001	0.241	0.071	0	0.071	0.000	0.000	0.000
2002	0.233	0.117	0	0.081	0.035	0.001	0.001
2003	0.180	0.105	0	0.102	0.002	0.001	0.000
Sycamore Canyon Wilderness							
2001	0.322	0.178	0	0.116	0.041	0.003	0.018
2002	0.470	0.202	0	0.117	0.082	0.001	0.003
2003	0.513	0.271	1	0.203	0.064	0.001	0.003
Zion NP							
2001	0.977	0.220	2	0.078	0.136	0.001	0.005
2002	0.569	0.156	1	0.041	0.108	0.001	0.006
2003	0.843	0.256	2	0.132	0.122	0.001	0.001

*The PM impacts represent the sum of the non-sulfate and non-nitrate PM species.

5. NO_X BART EVALUATION

Nitrogen oxides are produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. Thermal NO_x emissions are produced when elemental nitrogen in the combustion air is admitted to a high temperature zone and oxidized. Fuel NO_x emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel. It is also possible for nitrogenous compounds present in the raw material feed to be become oxidized to form additional NO_X. Due to the high flame temperature in the burning zone of the rotary kiln, most of the NO_x formed within a rotary lime kiln is thermal NO_x.

The baseline NO_x emission factors for Kilns 1 and 2 that were determined from the results of the 2013 CEMS testing, as detailed in Section 4 of this report, are shown in Table 5-1.

Table 5-1. Baseline NO_x Emission Factors

Unit	NO_X Emission Factor (lb/ton lime)
Kiln 1	7.59
Kiln 2	5.21

5.1. IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES

Step 1 of the BART determination is the identification of all available retrofit NO_x control technologies. The available retrofit NO_x technologies for Kilns 1 and 2 are summarized in Table 5-2.

Table 5-2. Available NO_X Control Technologies

NO_X Control Technologies
Low NO_X Burner (LNB)
Mixing Air Technology (MAT)
Selective Non-Catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)

5.2. ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible NO_x control technologies that were identified in Step 1.

5.2.1. Low NO_X Burner (LNB)

The main principle of the LNB is stepwise or staged combustion and localized exhaust gas recirculation (i.e., at the flame). LNBs are designed to reduce flame turbulence, delay fuel/air mixing, and establish fuel-rich zones for initial combustion. The longer, less intense flames resulting from the staged combustion lower flame temperatures and reduce thermal NO_x formation. However, the use of LNBs in lime kilns is not a widely used control technology, and past use of LNBs at the Nelson Plant was not successful.

In 2001, LNA experimented with the installation of bluff body LNBs on the Nelson lime kilns with the hope of achieving a shorter, more stabilized flame through a faster ignition in reducing conditions. This accelerated combustion under reducing conditions was intended to reduce NO_x formation. Unfortunately, the specific bluff body burners used in the Nelson kilns wore out in approximately six months, impacted production, caused brick damage, and resulted in unscheduled shutdowns of the kilns. Consequently, LNA discounts the use of bluff body LNBs and does not have reason to believe changing burners will reduce NO_x emissions by any specific percentage. Overall, LNA believes LNBs are not proven technology for shorter, preheater rotary kilns like those at the Nelson Plant.

LNA conducted a search of the EPA's RACT/BACT/LAER Clearinghouse (RBLC) for lime kiln permits issued since 2003 to determine if LNBs had been permitted as BACT in the lime industry. A summary table of the search results from the RBLC is provided in Appendix A. As shown in the RBLC summary table, none of the recent permitting actions have determined LNBs to be BACT, except the permitting action shown for the Western Lime Corporation. While the RBLC database indicates LNB was determined to be BACT for a Western Lime kiln, the LNB used by Western Lime in practice consists of a straight pipe with a bluff body. As stated above, LNA has experimented with bluff body LNBs on the Nelson kilns and was not successful.

There are several recent permitting actions that are not included in the RBLC. This includes a 2009 Prevention of Significant Deterioration (PSD) permit issued to Vulcan Construction Materials (VCM) for the restarting of a lime plant located in Manteno, Illinois and a 2009 PSD permit issued to Mississippi Lime Company (MLCo) for a new lime plant to be located in Prairie du Rocher, Illinois. Both of these permits contained BACT determinations for NO_x for the kilns. The BACT determinations for NO_x for both permits included the "use of preheaters or other similar heat recovery devices for improved fuel efficiency" and "low excess air". Neither of the permits required the use of LNBs.[5]

The fact that the most recent permits issued for lime kilns have not determined the use of LNBs to be BACT for NO_x means that LNBs also do not constitute BART. LNA has no data to suggest that NO_x reductions are achievable from changing to burners classified as LNBs. EPA has indicated that a 14 percent reduction in NO_X emissions may be anticipated in switching from a direct-fired standard burner to an indirect-fired LNB in a portland cement kiln (NO_x Control Technologies for the Cement Industry, EC/R Incorporated, Chapel Hill, NC, USA, U.S. EPA Contract No. 68-D98-025, U.S. EPA RTP, September 19, 2000). EPA has determined, however, that "the [emission reduction] contribution of the low- NO_x burner itself and of the firing system conversion [from direct to indirect] cannot be isolated from the limited data available." Further, portland cement kilns are different than lime kilns and it would not be appropriate to make the generalization that an anticipated reduction in a portland cement kiln is directly transferable to a lime kiln due to the different temperatures and operating conditions, which would be expected to impact NO_x generation rates.

Overall, as there is significant uncertainly with respect to the ability of a burner retrofit to reduce NO_x emissions, LNA considers LNBs to be technically infeasible.

5.2.2. Mixing Air Technology (MAT)

MAT is the practice of injecting a high pressure air stream into the middle of a kiln to help mix the air flowing through the kiln. MAT has been marketed in the portland cement industry as a solution for NO_x reduction in kilns that have stratified flow through the kiln, where the level of stratified flow is primarily dependent on the

[5] PSD permits issued to VCM and MLCo were appealed and in 2011, the permits were remanded back to the Illinois EPA. There has been no action on either of the permits since 2011. While the permits were appealed, it is important to note that the controls required by the NO_x BACT determination, including the use of preheater towers and low excess air to minimize NO_x, were not appealed.

burner design. The goal of using mixing air in portland cement kilns is to improve combustion efficiency. Improved combustion efficiency reduces NO_x emissions. Lime kilns can also have stratified flow, thus lime kilns may also be able to achieve NO_x reductions by using MAT.

Lime kilns are typically operated with a reducing atmosphere to enhance sulfur removal from the lime product. Thus, in addition to breaking up the stratified flow that may exist in a lime kiln, the injection of high velocity air into the middle of a kiln can create an oxidizing environment for the upper half of the kiln that may be effective at reducing NO_x emissions.[6] An oxidizing environment would have a negative impact on the lime quality from Kiln 2, as this kiln was originally designed to run in a reducing environment so it could manufacture lime product for the steel industry.

While the theory behind MAT suggests that the technology is effective at reducing NO_x emissions, the technology is so highly dependent on kiln-specific burners and operating conditions that it is impossible to assign a level of effectiveness for this technology to a specific kiln without testing and optimizing the technology on the specific kiln. LNA has no information to suggest that NO_x reductions can be achieved on the Nelson kilns based on the use of MAT. MAT has not been determined to be BART for any lime kiln. Further, MAT has not been determined to be BACT in any permit for a lime kiln issued in the last ten years, as evidenced by a search of the EPA's RBLC database for lime kilns and a review of recently issued permits. Thus, LNA considers MAT to be technically infeasible.

5.2.3. Selective Non-Catalytic Reduction (SNCR)

In SNCR systems, a reagent (ammonia or urea) is injected into the flue gas in an appropriate temperature window. The NO_x and reagent react to form nitrogen and water. A typical SNCR system consists of reagent storage, reagent-injection equipment, and associated control instrumentation. SNCR is a technically feasible option for reducing NO_x emissions from the Nelson kilns.

5.2.4. Selective Catalytic Reduction (SCR)

SCR refers to the process in which NO_x is reduced by a reagent (ammonia or urea) over a heterogeneous catalyst in the presence of oxygen to form nitrogen and water. The process is termed selective because the ammonia or urea preferentially reacts with NO_x rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. A typical SCR system consists of a reactor, a catalyst, an ammonia or urea storage and injection system, and associated control instrumentation. A common problem encountered with SCR systems in process industries, such as lime, is "poisoning" of the catalyst by trace metals or clogging/coating of the catalyst by dust. Once poisoned or covered, the catalyst can no longer perform its function and the SCR system is compromised. Given the operating temperature range for Kiln 1 and Kiln 2 at the Nelson Plant, the SCR catalyst would need to be located prior to the kiln baghouses. In this heavily dust laden environment, poisoning or covering of the catalyst is almost certain to occur in a short time period. While SCRs are common in some industries, there are no SCR systems currently operating on lime kilns. Thus, LNA considers SCR to be technically infeasible.

5.3. RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Table 5-3 summarizes the effectiveness of the technically feasible controls for NO_x, which in this case only includes SNCR.

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[6]Cadence Technical Bulletin: http://www.cadencerecycling.com/Resources/TechnicalBulletin%20Lime%20Kiln.pdf

Table 5-3. Effectiveness of Feasible NO_X Control Technologies

	Kiln	Baseline Emission Rate (lb/ton lime)	Baseline Emission Rate (lb/day)	Baseline Emission Rate (tpy)	Control Efficiency (%)	Controlled Emission Rate (lb/ton lime)	Controlled Emission Rate (lb/day)	Controlled Emission Rate (tpy)
SNCR	Kiln 1	7.59	6,571	981	50%	3.80	3,286	491
	Kiln 2	5.21	6,490	985	50%	2.61	3,245	493

As shown in Table 5-3, the effectiveness of SNCR for NO_x reduction is estimated to be 50%. LNA has not conducted any detailed design work for an SNCR system for the Nelson Plant kilns, but LNA anticipates that a 50% reduction is achievable based on LNA's experience with operating a urea-injection system at another LNA lime plant.

5.4. EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step four of the BART analysis is the impact analysis. The BART determination guidelines list four factors to be considered in the impact analysis:

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

5.4.1. Cost of Compliance

Table 5-4 provides a summary of the estimated cost for SNCR. The costs shown in Table 5-4 are based on LNA's experience with a urea injection system at another LNA lime plant.

Table 5-4. Estimated Cost for SNCR

Capital Costs	**Kiln 1**	**Kiln 2**	**Notes**
Total Capital Investment (TCI)	$450,000	$450,000	Based on LNA's experience with the purchase and installation of a urea injection system at another LNA Plant
Capital Recovery Factor (CRF)[1]	0.09	0.09	
Annual Costs			
Direct Annual Costs			
Urea usage (tons per year)	395	397	Based on LNA's experience with urea injection at another LNA Plant (1 lb urea reduces 1.24 lbs NOx)
Urea cost ($ per ton)	$826	$826	Based on LNA's experience with urea injection at another LNA Plant
Urea cost ($ per year)	$326,510	$327,995	
Operating labor ($ per year)	$37,500	$37,500	Based on LNA's experience with urea injection at another LNA Plant
Power usage (kW)	1.13	1.15	Based on LNA's experience with urea injection at another LNA Plant
Power usage (kW per year)	16320	16550	Based on LNA's experience with urea injection at another LNA Plant
Power cost ($ per kilowatt)	$0.06	$0.06	Based on power costs at the Nelson facility
Power cost ($ per year)	$979	$993	
Maintenance materials ($ per year)	$55,000	$55,000	Based on LNA's experience with urea injection at another LNA Plant
Total Direct Annual Costs	$419,989	$421,488	
Indirect Annual Costs (IC)			
Capital recovery	$42,477	$42,477	CRF* TCI
Total Indirect Annual Costs	$42,477	$42,477	
Total Annual Costs	$462,466	$463,965	
Baseline Emission Rate	981	985	
Control Efficiency	50%	50%	
Tons Reduced	490	493	
Control Cost in Dollars per Ton Reduced	**$943**	**$942**	

1: CRF = [I x(1+i)^a]/[(1+i)^a - 1], where I = interest rate (7%), a = equipment life (20 yrs)

5.4.2. Energy Impacts

As shown in Table 5-4, SNCR systems require electricity to operate the blowers and pumps. The generation of the electricity needed to operate an SNCR system will most likely involve fuel combustion. The combustion of fuel will generate emissions. Overall, while the generation of the required electricity will result in emissions, the emissions should be low compared to the reduction in NO_x that would be gained by operating an SNCR system.

5.4.3. Non-Air Quality Impacts

The operation of SNCR systems on Kiln 1 and Kiln 2 would require that either urea or ammonia be stored on site. The storage of the chemicals does not result in a direct non-air quality impact. However, the potential for the urea or ammonia that would be stored to leak or otherwise be released from the storage vessels means there is the potential for both air and non-air quality related impacts. The storage of these chemicals is regulated by other EPA programs, and the risks associated with the storage do not significantly impact the BART determination.

5.4.4. Remaining Useful Life

The remaining useful life of the kilns does not impact the annualized costs of SNCR because the useful life is anticipated to be at least as long as the capital cost recovery period, which is 20 years.

5.5. EVALUATION OF VISIBILITY IMPACT OF FEASIBLE NO_X CONTROLS

A final impact analysis was conducted to assess the visibility improvement associated with SNCR. Section 4 of this report documents the existing visibility impairment attributable to the kilns. In order to assess the visibility improvement associated with SNCR, the NO_x emission rates associated with SNCR were modeled using CALPUFF. The controlled NO_x emission rates for Kiln 1 and Kiln 2 associated with SNCR are summarized in Table 5-3. The controlled NO_x daily emission rates were used in the modeling. The emission rates for the other pollutants were the same as in the baseline modeling.

The visibility improvement associated with SNCR is summarized in Table 5-5. The greatest improvement in visibility impairment is predicted to occur in the Grand Canyon NP. Specifically, the application of SNCR is predicted to result in an improvement of 0.455 Δdv from the baseline 98th percentile impairment in the Grand Canyon NP of 1.586 Δdv, which is an improvement of 29%. This level of improvement in visibility impairment translates to cost of just over $2 million per Δdv of improvement (based on a total annual cost for Kiln 1 and Kiln 2 of $926,431 as shown in Table 5-4 above).

Table 5-5. Visibility Improvement Predicted for SNCR

	Baseline			SNCR			Improvement from Baseline		
Year	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv
Bryce Canyon NP									
2001	0.472	0.121	0	0.340	0.082	0	0.132	0.039	0
2002	0.291	0.131	0	0.205	0.092	0	0.086	0.039	0
2003	0.446	0.182	0	0.341	0.150	0	0.105	0.032	0
Grand Canyon NP									
2001	1.604	0.849	28	1.019	0.573	14	0.585	0.276	14
2002	2.684	0.996	36	2.005	0.654	20	0.679	0.342	16
2003	2.068	1.586	47	1.540	1.131	32	0.528	0.455	15
Joshua Tree NP									
2001	0.462	0.201	0	0.389	0.192	0	0.073	0.009	0
2002	0.330	0.174	0	0.260	0.167	0	0.070	0.007	0
2003	0.266	0.130	0	0.237	0.128	0	0.029	0.002	0
Mazatzal Wilderness									
2001	0.685	0.088	1	0.515	0.085	1	0.170	0.003	0
2002	0.292	0.140	0	0.252	0.118	0	0.040	0.022	0
2003	0.808	0.128	1	0.651	0.120	1	0.157	0.008	0
Pine Mountain Wilderness									
2001	1.001	0.088	1	0.728	0.080	1	0.273	0.008	0
2002	0.329	0.150	0	0.274	0.113	0	0.055	0.037	0
2003	0.867	0.122	2	0.689	0.110	1	0.178	0.012	1
Sierra Ancha Wilderness									
2001	0.328	0.063	0	0.259	0.061	0	0.069	0.002	0
2002	0.196	0.101	0	0.154	0.074	0	0.042	0.027	0
2003	0.278	0.102	0	0.248	0.094	0	0.030	0.008	0
Superstition Wilderness									
2001	0.241	0.071	0	0.192	0.071	0	0.049	0.000	0
2002	0.233	0.117	0	0.187	0.105	0	0.046	0.012	0
2003	0.180	0.105	0	0.164	0.104	0	0.016	0.001	0
Sycamore Canyon Wilderness									
2001	0.322	0.178	0	0.249	0.149	0	0.073	0.029	0
2002	0.470	0.202	0	0.338	0.171	0	0.132	0.031	0
2003	0.513	0.271	1	0.356	0.232	0	0.157	0.039	1
Zion NP									
2001	0.977	0.220	2	0.715	0.150	1	0.262	0.070	1
2002	0.569	0.156	1	0.375	0.108	0	0.194	0.048	1
2003	0.843	0.256	2	0.645	0.194	1	0.198	0.062	1

5.6. PROPOSED BART CONTROL AND EMISSION LEVELS

Based on the five step analysis outlined by EPA, SNCR has been identified as the sole technically feasible add-on control technology. Cost, energy and environmental impacts were assessed for this technology and the visibility improvements were evaluated against existing conditions. Overall, LNA believes that the cost of SNCR per ton of NO_x reduced is reasonable. Further, LNA believes that the level of improvement to visibility impairment, while not as tangible a variable as cost, is also reasonable. Neither non-air quality nor energy impacts associated with SNCR are considered significant and thus do not present a basis for eliminating SNCR in favor of retaining the existing emission rates as BART. Therefore, LNA proposes that SNCR is BART for NO_x for Kiln 1 and Kiln 2. LNA proposes to comply with a BART emission limit for Kiln 1 of 3.80 lb/ton lime on a 30-day rolling basis, as demonstrated through the use of a CEMS, and LNA proposes to comply with a BART emission limit for Kiln 2 of 2.61 lb/ton lime on a 30-day rolling basis, as demonstrated through the use of a CEMS. The proposed BART emission levels reflect a 50% reduction in the baseline NO_x emission levels.

LNA requests that the BART determination allow use of SNCR with urea or ammonia or other reactants or add-on technologies that will achieve the BART emission rate, subject to compliance with preconstruction review requirements. This provides LNA the opportunity to use the most cost effective mix of SNCR reagents to achieve the BART limit.

6. SO_2 BART EVALUATION

Sulfur dioxide is generated during fuel combustion in a lime kiln, as the sulfur in the fuel is oxidized in the combustion air. Sulfur in the limestone can also contribute to a kiln's SO_2 emissions.

The baseline SO_2 emission factors for Kilns 1 and 2 that were determined from the results of the 2013 CEMS testing, as detailed in Section 4 of this report, are shown in Table 5-1.

Table 6-1. Baseline SO_2 Emission Factors

Unit	SO_2 Emission Factor (lb/ton lime)
Kiln 1	12.15
Kiln 2	12.69

6.1. IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES

Step 1 of the BART determination is the identification of all available retrofit SO_2 control technologies. The available retrofit SO_2 control technologies are summarized in Table 6-2.

Table 6-2. Available SO_2 Control Technologies

SO_2 Control Technologies
Semi-Dry Scrubbing
Wet Scrubbing
Dry Sorbent Injection
Lower Sulfur Fuel

6.2. ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

6.2.1. Semi-Dry Scrubbing

A semi-dry scrubbing system consists of a scrubber tower followed by a particulate matter control device. Flue gas enters the scrubber tower and is sprayed with an atomized hydrated lime slurry. The lime absorbs the SO_2 in the exhaust and turns the SO_2 into solid calcium/sulfur compounds. The particulate matter control device removes the solids from the exhaust stream.

Water is required to make the hydrated lime slurry needed for semi-dry scrubbing. As the Nelson Plant is in an area with limited water supply, LNA contacted a supplier of SO_2 scrubbing systems to understand the water requirements associated with a semi-dry system capable of achieving a 90% reduction in SO_2 emissions on the Nelson kilns. The supplier estimated that Kiln 1 and Kiln 2 would require 50 gallons per minute (gpm) and 67 gpm of water, respectively, for a total of 117 gpm.

The Nelson Plant currently operates two groundwater wells at over 800 feet deep. The Primary Well that supplies the drinking and fire protection water for the plant yields approximately 46 gpm. The Canyon Well that supplies water for the quarry, crushing and screening plant, and hydrator yields approximately 60 gpm. In total, the available water supply to the plant is 106 gpm. According to a 1998 hydrologic report, the water demand of the Nelson Plant is approximately 80 gpm. This demand has not increased significantly since 1998 and thus likely represents a good estimate of the current water demand at the facility. When the current water demand of 80 gpm is accounted for, only 26 gpm of water would be available for a scrubbing system. Based on the water demands that LNA has been provided for a semi-dry scrubbing (117 gpm), LNA has concluded that there is not currently sufficient water available for this type of system. Additionally, the 1998 hydrologic report referenced above indicates that the prospects for developing additional even low-yield wells on the Nelson property are poor.

Due to the fact that the water necessary for a semi-dry scrubbing system at the Nelson Plant is currently unavailable and ability to reasonably access additional water is not probable, this technology will not be considered further in the BART control review for SO_2.

6.2.2. Wet Scrubbing

In a typical wet 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 (typically) 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. Most wet scrubber systems use forced oxidation to assure that only calcium sulfate sludge is produced.

LNA does not have specific information on the water requirements for wet scrubbers for the kilns but such scrubbers certainly require more water than semi-dry scrubbing systems. Since there is not enough water available for semi-dry scrubbing systems for the kilns, there is also not enough water available for wet scrubbing. Due to the fact that sufficient water is not available for a wet scrubbing system, wet scrubbing technology will not be considered further.

6.2.3. Dry Sorbent Injection

Dry sorbent injection (DSI) involves injecting dry sorbent directly into the flue gas or exhaust stream. The sorbent reacts with SO_2 in the exhaust to form solid particles that are then removed by a particulate matter control device downstream of the sorbent injection. The effectiveness of DSI is dependent on the type or sorbent, amount of sorbent used, the temperature of the exhaust gas at the time of contact with the sorbent, and the residence time of the sorbent in the exhaust. LNA believes DSI is technically feasible for the Nelson kilns.

6.2.4. Lower Sulfur Fuel Blend

The use of a fuel blend that is lower in sulfur than the fuel blend currently used is a possible method for reducing SO_2 emissions from lime kilns. SO_2 emissions would generally be expected to drop in proportion to the reduction in the fuel sulfur level.

LNA currently uses a blend of 27% coal and 73% petroleum coke, on a mass basis, as the fuel for the kilns. Since coke has about 4 to 5 times more sulfur than coal, it is possible to decrease the sulfur in the fuel blend by increasing the coal portion. However, an increase in coal in the fuel blend will also increase the ash content of the fuel blend. Ash in the fuel can cause disruptive operational issues in the form of buildup of ash rings in the kilns. A fuel blend with an ash content of about 6.5% or less must be used in order to avoid these operational challenges. Natural gas is not currently available at the Nelson Plant, so it will not be considered in this analysis.

6.3. RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. The effectiveness of the technically feasible controls for SO_2, which in this case includes DSI and a lower sulfur fuel blend, are summarized in Table 6-3. Additional discussion on the effectiveness of both DSI and a lower sulfur fuel blend is provided below.

Table 6-3. Effectiveness of Feasible SO_2 Control Technologies

SO_2 Control Technology	Kiln	Baseline Emission Rate (lb/ton lime)	Baseline Emission Rate (lb/day)	Baseline Emission Rate (tpy)	Control Efficiency (%)	Controlled Emission Rate (lb/ton lime)	Controlled Emission Rate (lb/day)	Controlled Emission Rate (tpy)
Dry Sorbent Injection	Kiln 1	12.15	10,526	1,571	40%	7.29	6,316	943
	Kiln 2	12.69	15,808	2,400	40%	7.61	9,485	1440
Lower Sulfur Fuel Blend	Kiln 1	12.15	10,526	1,571	23.3%	9.32	8,073	1,205
	Kiln 2	12.69	15,808	2,400	23.3%	9.73	12,125	1,841

6.3.1. Effectiveness of Lower Sulfur Fuel Blend

As stated in Section 6.2.4 of this report, the ash content of the fuel burned in the kilns cannot exceed 6.5% without posing operational challenges due to the buildup of ash rings in the kiln. On average, the ash content of coal is about 5 to 6 times higher than the ash content of coke. For this report, LNA conducted an analysis to determine the maximum amount of coal that can be included in the fuel blend as a replacement for coke without exceeding approximately 6.5% ash for the blend. LNA then determined the reduction in sulfur associated with burning a fuel blend with approximately 6.5% ash.

From 2007 to 2012, the ash content of the coal averaged 9.72% and the ash content of the coke averaged 0.98%. [7] While the average ash content of the coal from 2007 to 2012 was less than 10%, it is common for LNA to receive back to back coal shipments over several weeks with an ash content well above 10%. For example, the highest monthly average ash content of the coal from 2007 to 2012 was 15.73% (May 2009) with 26 months having averages over 10%. Thus, in order to characterize future fuel blends, average ash values for the coal of greater then 10% must be considered.

In order to determine the ash content of the coal to be used in estimating the maximum amount of coal that can be included in a coal/coke blend without exceeding 6.5% ash, LNA conducted a statistical analysis on the monthly average ash contents of the coal. Taking the average of the 2007 to 2012 monthly averages plus one standard deviation, the ash content of the coal is 11.35%. Conducting the same statistical analysis on the ash content of the coke results in an ash content for coke of 1.62%. Based on these ash contents, the maximum amount of coal that can be burned (by weight) without exceeding an ash content for the fuel blend of 6.5% is

[7] The ash values were estimated by taking an average of the average monthly ash and sulfur levels from 2007 to 2012.

50%. [8] Therefore, assuming a drop in fuel sulfur is directly proportional to a reduction in SO_2 emissions, an increase in coal usage up to 50% of the total fuel mass is estimated to result in a 23.3% reduction in SO_2.[9]

6.3.2. Effectiveness of DSI

It is challenging to estimate the effectiveness of DSI for the Nelson lime kilns. There are a number of variables that impact the effectiveness of DSI, several of which are site specific. These variables include, but are not limited to, the following:

- Temperature of exhaust stream where sorbent is injected
- Moisture content of the exhaust stream
- Competing acid gases, which include CO_2, HCl, SO_3
- Characteristics of sorbent used (e.g., particle surface area)
- Amount of sorbent used
- Sorbent injection location
- Residence time for sorbent/SO_2 interaction
- CO_2 and CO levels in the kiln system

Overall, the variables that impact the effectiveness of DSI make it difficult to estimate the level of effectiveness that can be expected for DSI for the Nelson kilns. Nevertheless, for purposes of this BART analysis, LNA has estimated the control effectiveness of DSI to be 40%. This control effectiveness is based on a combination of the following:

- Limited testing that LNA conducted on the Nelson lime kilns in June 2013 using both standard hydrated lime manufactured at the plant as well as Sorbacal® SPS
- Vendor data for a DSI system using sodium bicarbonate (SBC).
- LNA testing of Sorbacal® SP on a cement kiln in North America (effective reduction 70% -LNA anticipates similar results would have occurred with use of Sorbacal® SPS)
- Data from Tables 5 and 6 of the October 2012 UNC/ICF BART Five Factor Analysis for the Nelson Lime Plant (DSI with SBC = 75%)

<u>LNA Testing at Nelson Plant</u>
LNA conducted some extremely limited trial runs of DSI on both of the Nelson lime kilns in June of 2013 to evaluate the impact of DSI on the SO_2 emission rates, as described in Appendix B of this report. The trials runs tested the use of both standard hydrated lime manufactured at the Nelson Plant as well as Sorbacal® SPS brought in from the LNA St. Genevieve Plant in Missouri. The trial runs suggested that Sorbacal® SPS is more effective than the standard hydrated lime and that the effectiveness of Sorbacal® SPS appears to be dependent on the amount of sorbent used, injection location and residence time of the sorbent in the ductwork. Certainly kiln process variables may also influence the effectiveness of DSI but the testing period was too short to identify these variables. Overall, the test data suggest that a 40% SO_2 reduction is likely achievable based on the use of Sorbacal® SPS at a 9:1 mass ratio of sorbent to SO_2 reduction.

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[8] A blend of 50% coal with 11.35% ash and 50% coke with 1.62% ash has an ash content of 6.5% (50% *11.35%* + 50% * 1.62% = 6.5%)

[9] For baseline, a blend of 27% coal with 1.15% sulfur and 73% coke with 5.64% sulfur has a sulfur content of 4.43%. For the future, a blend of 50% coal with 1.15% sulfur and 50% coke with 5.64% sulfur has a sulfur content of 3.40%. The difference in sulfur is 1.13%, which is a 23.3% reduction from baseline.

Vendor Data for DSI Systems

LNA obtained two quotes for the equipment associated with a DSI system. One quote was from Dustex Corporation and the other from Noltech Systems. The quote from Noltech was based on the use of Sorbacal® SP, but the quote did not specify a usage rate or a level of SO_2 reduction. The quote from Dustex was based on the use of SBC. The Dustex quote contained limited information on the expected level of SO_2 reduction, and it contained no information on the usage rate of SBC. More specifically, in the introductory paragraph of the Dustex quote, where the DSI system is described in general terms, Dustex includes the statement "*A typical SBC system can remove up to 60% SO_2*". Based on this statement, LNA followed up with Dustex to ask for additional information related to the 60% reduction. In a series of emails Dustex: (1) claimed a 50% removal is achievable but did not provide any experience with lime plants to support this claim; and (2) stated they assume 5 lbs of SBC per pound of SO_2 in order to get up to 60% removal efficiency.

While Dustex has provided the above information, based on the fact that Dustex has never installed a DSI system on a lime kiln, LNA considers these usage and removal data as broad estimates only.

LNA Testing of Sorbacal® SPS on a Cement Kiln in North America

Injection trials within the cement industry in Europe have led to the commercial use of Sorbacal® SP/SPS for the reduction of SO_2. Based on the success in Europe, in 2011 LNA conducted DSI testing on a four stage preheater/precalciner kiln at a North American cement plant using Sorbacal® SP. The study showed that injection of Sorbacal® SP at the ID fan, where the temperature is approximately 720 °F, resulted in a reduction in SO_2 of approximately 70%. LNA would expect similar results with Sorbacal® SPS and believes the Sorbacal® products (SP/SPS) are similar in performance with SBC.

2012 UNC/ICF BART Five Factor Analysis

Tables 5 and 6 of the 2012 UNC/ICF BART Five Factor Analysis indicate that DSI using SBC can achieve SO_2 reduction of 75%. The report provides no basis for this control value, but based on several comments in the report, it suggests that the value is reflective of what UNC/ICF believes may be achievable for a cement kiln using SBC. LNA has shown that a value of 70% reduction using Sorbacal® SP in a cement kiln is achievable. In addition, LNA considers SBC and Sorbacal® SP/SPS to be similar SO_2 sorbents that are capable of approximately 70% reduction in the cement industry.

While it may be possible to achieve 70% reduction in SO_2 in the cement industry based on the use of a DSI system, this level of efficiency has never been demonstrated in practice on a lime kiln and has certainly not been demonstrated on the Nelson lime kilns. One primary difference between the cement kiln that LNA tested and the Nelson lime kilns is the temperature of the exhaust gas. The exhaust gas from the preheater/precalciner cement kiln at the location of the ID fan where the Sorbacal® SP was injected was approximately 720 °F. The exhaust gas where the Sorbacal® SPS was injected during the Nelson kiln testing was between 350 and 450 °F (depending on the kiln). Significantly, given the lower temperature of the exhaust gas of Nelson kilns compared to the temperature of the exhaust gas of the tested cement kiln, and the well established relationship of temperature and DSI SO_2 removal, the same degree of effectiveness of the SO_2 removal for the Nelson kilns compared to that of a cement kiln would and should not be expected.

The UNC/ICF report states that SBC is similar to hydrated lime in SO_2 reduction and that LNA may choose to use the hydrated lime that they manufacture at the Nelson Plant in place of SBC, as it is capable of similar levels of SO_2 control. The report goes on to say that DSI using SBC provides a reasonable surrogate for estimating the control of DSI using standard hydrated lime. LNA disagrees. SBC is considered by the DSI industry to be a high performance sorbent and has a much higher surface area than the standard hydrated lime manufactured at the

Nelson Plant. Thus, SBC would be expected to perform better than the standard hydrated lime manufactured at the Nelson Plant in the same way that Sorbacal® SPS was found during the June 2013 testing at the Nelson Plant to perform significantly better than the hydrated lime manufactured at the Nelson Plant.

<u>Conclusions Regarding DSI Sorbent Control Efficiencies</u>

Based on an evaluation of all the above factors, LNA believes that Sorbacal® SPS will perform well and by extension, so too would SBC when used for SO_2 reduction for the Nelson lime kilns. Based on the limited CEMS testing at the Nelson Plant in June 2013 using Sorbacal® SPS, the SO_2 reduction effectiveness is approximately 40% . It is assumed that because SBC and Sorbacal® SPS react with SO_2 based on similar chemical principles, LNA expects SBC would have a similar SO_2 control efficiency of 40%. This contrasts to the 70% control efficiency documented with cement kilns, which is attributed to significantly higher temperatures of the cement kiln exhaust gas, and therefore higher efficiencies. Consequently, LNA has used 40% for estimating the control efficiency of both SBC and Sorbacal® SPS.

6.4. EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS

Step four of the BART analysis is the impact analysis. The BART determination guidelines list four factors to be considered in the impact analysis:

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

6.4.1. Cost of Compliance

A summary of the estimated annual cost effectiveness for DSI and switching to a lower sulfur fuel blend is provided in Table 6-4. Individual summaries of the cost effectiveness of a DSI system using Sorbacal® SPS, the cost effectiveness of a DSI system using SBC, and the cost effectiveness of using a reduced sulfur fuel blend are provided in Tables 6-5, 6-6, and 6-7, respectively.

Table 6-4. Summary of the Estimated Cost Effectiveness for SO_2 Controls

Kiln 1

Technology	Baseline Emission Rate	Control Efficiency	Controlled Emission Rate	SO_2 Reduced	Capital Investment	Annual Direct Costs	Annual Indirect Costs	Total Annual Cost	Cost Effectiveness
	(tpy)	%	(tpy)	(tpy)	($)	($/yr)	($/yr)	($/yr)	($/ton)
DSI with SBC	1,571	40	943	628	2,497,559	3,134,147	348,348	3,482,495	5,542
DSI with Sorbacal® SP	1,571	40	943	628	2,497,559	3,001,455	348,348	3,349,803	5,331
Fuel Switching (50%/50% Coke/Coal Blend)	1,571	23	1,205	366	NA	NA	NA	422,213	1,152

Kiln 2

Technology	Baseline Emission Rate	Control Efficiency	Controlled Emission Rate	SO_2 Reduced	Capital Investment	Annual Direct Costs	Annual Indirect Costs	Total Annual Cost	Cost Effectiveness
	(tpy)	%	(tpy)	(tpy)	($)	($/yr)	($/yr)	($/yr)	($/ton)
DSI with SBC	2,400	40	1,440	960	2,497,559	4,725,749	348,348	5,074,097	5,286
DSI with Sorbacal® SP	2,400	40	1,440	960	2,497,559	4,523,056	4,871,404	4,871,404	5,075
Fuel Switching (50%/50% Coke/Coal Blend)	2,400	23	1,840	560	NA	NA	NA	617,859	1,104

Table 6-5. Estimated Cost Effectiveness for DSI Using Sorbacal® SPS

Capital Costs	**Kiln 1**	**Kiln 2**	**Notes**
Equipment Cost (EC)	$1,022,500	$1,022,500	Noltech quote - May 22, 2013
Instrumentation (10% of EC)	$102,250	$102,250	CCM, Section 5.2, Chapter 1, Table 1.3
Sales taxes (3% of EC)	$30,675	$30,675	CCM, Section 5.2, Chapter 1, Table 1.3
Freight (5% of EC)	$51,125	$51,125	CCM, Section 5.2, Chapter 1, Table 1.3
Purchased Equipment Cost (PEC)	$1,206,550	$1,206,550	
Direct Installation Costs:			
Foundation & Supports (12% of PEC)	$144,786	$144,786	CCM, Section 5.2, Chapter 1, Table 1.3
Handling & Erection (40% of PEC)	$482,620	$482,620	CCM, Section 5.2, Chapter 1, Table 1.3
Electrical (1% of PEC)	Included in EC	Included in EC	CCM, Section 5.2, Chapter 1, Table 1.3
Piping (30% of PEC)	$361,965	$361,965	CCM, Section 5.2, Chapter 1, Table 1.3
Insulation for ductwork (1% of PEC)	$12,066	$12,066	CCM, Section 5.2, Chapter 1, Table 1.3
Painting (1% of PEC)	Included in EC	Included in EC	CCM, Section 5.2, Chapter 1, Table 1.3
Indirect Installation Costs:			
Engineering (10% of PEC)	Included in EC	Included in EC	CCM, Section 5.2, Chapter 1, Table 1.3
Construction and field expenses (10% of PEC)	$120,655	$120,655	CCM, Section 5.2, Chapter 1, Table 1.3
Contractor fees (10% of PEC)	$120,655	$120,655	CCM, Section 5.2, Chapter 1, Table 1.3
Performance test (1% of PEC)	$12,066	$12,066	CCM, Section 5.2, Chapter 1, Table 1.3
Contingencies (3% of PEC)	$36,197	$36,197	CCM, Section 5.2, Chapter 1, Table 1.3
Total Capital Investment (TCI)	$2,497,559	$2,497,559	
Capital Recovery Factor (CRF)[1]	0.09	0.09	
Annual Costs			
Direct Annual Costs (DC)			
Mass ratio of sorbent needed per ton of SO2 reduced	9	9	Based on DSI testing conducted with Sorbacal® SPS in June 2013 at LNA's Nelson plant
Sorbent usage (tons per year)	5,656	8,639	
Sorbent cost ($/ton)	$250	$250	Estimated price point for Sorbacal® SPS in AZ market - priced to match trona
Sorbent transportation cost ($/ton)	$260	$260	Cost to truck from St. Genevieve, MO to LNA's Nelson plant
Annual sorbent cost ($ per year)	$2,884,333	$4,405,935	
Annual cost for increased bag replacement (3 yrs vs 5 yrs)	$60,750	$60,750	LNA estimate: $450,000 per kiln for bags, cages, and labor Over 20 yr life: $450,000*4 replacements (every 5 yrs)/20 yrs = $90,000/yr Over 20 yr life: $450,000*6.7 replacements (every 3 yrs)/20 yrs = $150,750/yr
General Labor Cost ($/hr)	$25	$25	LNA Estimate
General O&M labor (dollars per year)	$8,463	$8,463	LNA Estimate: Operation: 1/2hr per day, Maintenance: 3 hrs per week
General O&M materials (dollars per year)	$12,694	$12,694	LNA Estimate: Operating materials are 1.5 times operating labor costs
Auxiliary power usage (kWh per year)	586,920	586,920	Based on NolTech Quotation (90 hp blowers = 67 kW)
Power cost (dollar per kWh)	$0.06	$0.06	Based on power costs at the Nelson facility
Annual Power cost ($)	$35,215	$35,215	
Total Direct Annual Costs	$3,001,455	$4,523,056	
Indirect Annual Costs (IC)			
Overhead (60% of labor and material costs)	$12,694	$12,694	CCM, Section 5.2, Chapter 1, Table 1.4
Administrative charges (2% of TCI)	$49,951	$49,951	CCM, Section 5.2, Chapter 1, Table 1.4
Property Tax (1% of TCI)	$24,976	$24,976	CCM, Section 5.2, Chapter 1, Table 1.4
Insurance (1% of TCI)	$24,976	$24,976	CCM, Section 5.2, Chapter 1, Table 1.4
Capital recovery (TCI * CRF)	$235,752	$235,752	CCM, Section 5.2, Chapter 1, Table 1.4
Total Indirect Annual Costs	$348,348	$348,348	
Total Annual Costs	$3,349,803	$4,871,404	
Baseline Emission Rate (tpy)	1,571	2,400	
Control Efficiency	40%	40%	Based on DSI testing conducted with Sorbacal® SPS in June 2013 at LNA's Nelson plant
Tons Reduced	628	960	
Control Cost in Dollars per Ton Reduced	**$5,331**	**$5,075**	

1. CRF = [I x(1+i)^a]/[(1+i)^a - 1], where I = interest rate (7%), a = equipment life (20 yrs)

Table 6-6. Estimated Cost Effectiveness for DSI Using SBC

Capital Costs	Kiln 1	Kiln 2	Notes
Equipment Cost (EC)	$1,022,500	$1,022,500	Noltech quote - May 22, 2013
Instrumentation (10% of EC)	$102,250	$102,250	CCM, Section 5.2, Chapter 1, Table 1.3
Sales taxes (3% of EC)	$30,675	$30,675	CCM, Section 5.2, Chapter 1, Table 1.3
Freight (5% of EC)	$51,125	$51,125	CCM, Section 5.2, Chapter 1, Table 1.3
Purchased Equipment Cost (PEC)	$1,206,550	$1,206,550	
Direct Installation Costs:			
Foundation & Supports (12% of PEC)	$144,786	$144,786	CCM, Section 5.2, Chapter 1, Table 1.3
Handling & Erection (40% of PEC)	$482,620	$482,620	CCM, Section 5.2, Chapter 1, Table 1.3
Electrical (1% of PEC)	Included in EC	Included in EC	CCM, Section 5.2, Chapter 1, Table 1.3
Piping (30% of PEC)	$361,965	$361,965	CCM, Section 5.2, Chapter 1, Table 1.3
Insulation for ductwork (1% of PEC)	$12,066	$12,066	CCM, Section 5.2, Chapter 1, Table 1.3
Painting (1% of PEC)	Included in EC	Included in EC	CCM, Section 5.2, Chapter 1, Table 1.3
Indirect Installation Costs:			
Engineering (10% of PEC)	Included in EC	Included in EC	CCM, Section 5.2, Chapter 1, Table 1.3
Construction and field expenses (10% of PEC)	$120,655	$120,655	CCM, Section 5.2, Chapter 1, Table 1.3
Contractor fees (10% of PEC)	$120,655	$120,655	CCM, Section 5.2, Chapter 1, Table 1.3
Performance test (1% of PEC)	$12,066	$12,066	CCM, Section 5.2, Chapter 1, Table 1.3
Contingencies (3% of PEC)	$36,197	$36,197	CCM, Section 5.2, Chapter 1, Table 1.3
Total Capital Investment (TCI)	$2,497,559	$2,497,559	
Capital Recovery Factor (CRF)[1]	0.09	0.09	
Annual Costs			
Direct Annual Costs (DC)			
Mass ratio of sorbent needed per ton of SO2 reduced	6.5	6.5	Based on email from Dustex to Gideon Siringi of LNA dated 04.03.13: "We usually assume 5 pounds SBC per pound of SO2..." plus a 30% safety factor
Sorbent usage (tons per year)	4,085	6,239	
Sorbent cost ($/ton)	$600	$600	http://sodaashdirect.com/buy-sodium-carbonate-online.html#sodbicarb
Sorbent transportation cost ($/ton)	$139	$139	$138.64 for transporting SBC from Green River, WY to the plant (transportation cost provided by Tom Hughes to Ed Barry in an email dated 7.10.13).
Annual sorbent cost ($ per year)	$3,017,025	$4,608,627	
Annual cost for increased bag replacement (3 yrs vs 5 yrs)	$60,750	$60,750	LNA estimate: $450,000 per kiln for bags, cages, and labor Over 20 yr life: $450,000*4 replacements (every 5 yrs)/20 yrs = $90,000 Over 20 yr life: $450,000*6.7 replacements (every 3 yrs)/20 yrs = $150,750
General Labor Cost ($/hr)	$25	$25	LNA Estimate
General O&M labor (dollars per year)	$8,463	$8,463	LNA Estimate: Operation: 1/2hr per day, Maintenance: 3 hrs per week
General O&M materials (dollars per year)	$12,694	$12,694	LNA Estimate: Operating materials are 1.5 times operating labor costs
Auxiliary power usage (kWh per year)	586,920	586,920	Based on NolTech Quotation (90 hp blowers = 67 kW)
Power cost (dollar per kWh)	$0.06	$0.06	Based on power costs at the Nelson facility
Annual Power cost ($)	$35,215	$35,215	
Total Direct Annual Costs	$3,134,147	$4,725,749	
Indirect Annual Costs (IC)			
Overhead (60% of labor and material costs)	$12,694	$12,694	CCM, Section 5.2, Chapter 1, Table 1.4
Administrative charges (2% of TCI)	$49,951	$49,951	CCM, Section 5.2, Chapter 1, Table 1.4
Property Tax (1% of TCI)	$24,976	$24,976	CCM, Section 5.2, Chapter 1, Table 1.4
Insurance (1% of TCI)	$24,976	$24,976	CCM, Section 5.2, Chapter 1, Table 1.4
Capital recovery (TCI * CRF)	$235,752	$235,752	CCM, Section 5.2, Chapter 1, Table 1.4
Total Indirect Annual Costs	$348,348	$348,348	
Total Annual Costs	$3,482,495	$5,074,097	
Baseline Emission Rate (tpy)	1,571	2,400	
Control Efficiency	40%	40%	Dustex indicated 60% for SBC in their quote to LNA for a DSI system but reduced this to 50% in an email ("*we are willing to guarantee 50% ...*"). NolTech did not include estimated levels of SO2 control in their quote for a DSI system. Since no substantive basis was provided by any vendor for a specific level of control (since DSI for SO2 control has not been demonstrated on a lime kiln), LNA defaults to the efficiency estimated for Sorbacal® SPS based on DSI testing conducted with Sorbacal® SPS in June 2013 at LNA's Nelson plant. LNA consideres Sorbacal® SPS to be similar to SBC.
Tons Reduced	628	960	
Control Cost in Dollars per Ton Reduced	**$5,542**	**$5,286**	

1: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate (7%), a = equipment life (20 yrs)

Table 6-7. Estimated Cost Effectiveness for Lower Sulfur Fuel Blend

Fuel Data	Kiln 1	Kiln 2	Units	Notes
Baseline and Future Coal Heating Value	26.4	26.4	MMBtu/ton	Heating value based on average from 2007 to 2012
Baseline and Future Coke Heating Value	29.8	29.8	MMBtu/ton	Heating value based on average from 2007 to 2012
Baseline Coal Cost	113	113	$/ton	
Future Coal Cost	119	119	$/ton	Coal costs expected to rise approximately 5%
Baseline Coke Cost	94	94	$/ton	
Future Coke Cost	94	94	$/ton	Coke prices not expected to rise
Baseline Coal Sulfur Content	1.15	1.15	%	Sulfur content based on average from 2007 to 2012 plus 1 std dev
Baseline Coke Sulfur Content	5.64	5.64	%	Sulfur content based on average from 2007 to 2012 plus 1 std dev
Future Coal Sulfur Content	1.15	1.15	%	Sulfur content based on average from 2007 to 2012 plus 1 std dev
Future Coke Sulfur Content	5.64	5.64	%	Sulfur content based on average from 2007 to 2012 plus 1 std dev
Baseline Coal Use	11,651	17,050	tons	Baseline coal used based on average from 2007 to 2012
Baseline Coke Use	31,501	46,099	tons	Baseline coke used based on average from 2007 to 2012
Baseline Fuel Cost (73% Coke/27% Coal)	$4,282,063	$6,266,295	$/yr	
Baseline Fuel Sulfur Content (73% Coke/27% Coal)	4.43	4.43	%	
Lime Production Data	**Kiln 1**	**Kiln 2**	**Units**	
Heat input required for lime	4.8	4.8	MMBtu/ton	
Annual Lime Production	258,508	378,296	tpy	Lime production based on the calendar year with the highest historical production rate (2010 production for Kiln 1 and 2012 production for Kiln 2)
Total Annual Heat Input Required	1,240,838	1,815,821	MMBtu/yr	
Fuel Switching Costs ($/yr)	**Kiln 1**	**Kiln 2**	**Units**	
Heat value of 50% coke/50% coal blend	28.1	28.1	MMBtu/ton	
Total fuel mass required for 50% coke/50% coal blend	44,207	64,691	tpy	
Amount of coal required (50%)	22,103	32,346	Tons	
Amount of coke required (50%)	22,103	32,346	Tons	
Annual cost for 50% Coke/50% Coal blend	$4,704,276	$6,884,154	$/yr	
Cost above baseline for 50% Coke/50% Coal blend	$422,213	$617,859	$/yr	
SO2 Reduction Analysis	**Kiln 1**	**Kiln 2**	**Units**	
Sulfur content of 50% Coke/50% Coal blend	3.40	3.40	%	
Sulfur reduction from switching to 50% Coke/50% Coal	23.3	23.3	%	
Baseline Emission Rate	1,571	2,400	tpy	
Tons Reduced	366	560	tpy	
Control Cost in Dollars per Ton Reduced	$1,152	$1,104	$/ton	

6.4.2. Energy Impacts

DSI systems require electricity for operation. The generation of the electricity needed to operate a DSI system will most likely involve fuel combustion. The combustion of fuel will generate emissions. There will also be emissions associated with the transport, handling, and storage of sorbent. Overall, while the use of DSI will cause emissions from select activities, the emissions should be low compared to the reduction in SO_2 that would be gained by operating a DSI system.

Using a lower sulfur fuel blend means LNA will obtain more of the energy for lime production from coal and less of the energy from coke. Since the heating value of coke is slightly higher than the heating value of coal, it is likely that LNA will burn more total mass of fuel as a result of substituting some coal for coke. While burning a lower sulfur fuel blend will likely result in a reduction in SO_2 emissions, the impact of burning a lower sulfur fuel blend on other pollutants such as NO_x and CO is unknown.

6.4.3. Non-Air Quality Impacts

The operation of DSI systems on Kiln 1 and Kiln 2 would require sorbent to be stored on site. The storage of sorbent is generally not associated with any non-air quality impacts.

There are no non-air quality impacts from using a lower sulfur fuel blend that would impact the BART determination.

6.4.4. Remaining Useful Life

The remaining useful life of the kilns does not impact the annualized costs of DSI because the useful life is anticipated to be at least as long as the capital cost recovery period, which is 20 years. There are no capital costs associated with using a lower sulfur fuel blend, thus the remaining useful life of the kilns is not a factor in the evaluation of this technology.

6.5. EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS

A final impact analysis was conducted to assess the visibility improvement associated with DSI and switching to a lower sulfur fuel blend. Section 4 of this report documents the existing visibility impairment attributable to the kilns. In order to assess the visibility improvement associated with DSI and fuel switching, the SO_2 emission rates associated with these technologies were modeled using CALPUFF. The controlled SO_2 emission rates for Kiln 1 and Kiln 2 associated with DSI and using a lower sulfur fuel blend are summarized in Table 6-3 above.

The visibility improvement associated with DSI is shown in Table 6-8. Additional details on the visibility improvement analysis are included in the spreadsheet submitted with this report. As shown in Table 6-8, the greatest improvement in visibility impairment is predicted to occur in the Grand Canyon NP. Specifically, DSI is predicted to result in a maximum improvement of 0.162 Δdv from the baseline 98th percentile impairment of 1.586 Δdv, which is an improvement of 10%. This level of improvement in visibility impairment translates to the following costs per deciview:

- DSI Using Sorbacal® SPS = $50,748,191 /Δdv (From Table 6-5: K1 annual cost = $3,349,803, K2 annual cost = $4,871,404, K1 annual cost + K2 annual cost = $8,221,207)
- DSI Using SBC = $53,146,528/Δdv (From Table 6-6: K1 annual cost = $3,482,495, K2 annual cost = $5,074,097, K1 annual cost + K2 annual cost = $8,556,591)

The visibility improvement associated with the use of a lower sulfur fuel blend is summarized in Table 5-56-9. The greatest improvement in visibility impairment is predicted to occur in the Grand Canyon NP. Specifically, the use of a lower sulfur fuel blend is predicted to result in an improvement of 0.106 Δdv from the baseline 98th percentile impairment of 1.586 Δdv, which is an improvement of 7%. This level of improvement in visibility impairment translates to cost of $9,812,000 million per Δdv of improvement (based on a total annual cost for Kiln 1 and Kiln 2 of $1,040,072, where Kiln 1 = $422,213 and Kiln 2 = $617,859, as shown in Table 6-7 above).

Table 6-8. Visibility Improvement Predicted for DSI

Bryce Canyon NP									
	Baseline			DSI			Improvement from Baseline		
Year	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv
2001	0.472	0.121	0	0.391	0.109	0	0.081	0.012	0
2002	0.291	0.131	0	0.250	0.115	0	0.041	0.016	0
2003	0.446	0.182	0	0.354	0.132	0	0.092	0.050	0
Grand Canyon NP									
	Baseline			DSI			Improvement from Baseline		
Year	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv
2001	1.604	0.849	28	1.482	0.760	23	0.122	0.089	5
2002	2.684	0.996	36	2.570	0.889	30	0.114	0.107	6
2003	2.068	1.586	47	1.972	1.424	44	0.096	0.162	3
Joshua Tree NP									
	Baseline			DSI			Improvement from Baseline		
Year	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv
2001	0.462	0.201	0	0.341	0.141	0	0.121	0.060	0
2002	0.330	0.174	0	0.257	0.118	0	0.073	0.056	0
2003	0.266	0.130	0	0.184	0.085	0	0.082	0.045	0
Mazatzal Wilderness									
	Baseline			DSI			Improvement from Baseline		
Year	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv
2001	0.685	0.088	1	0.553	0.063	1	0.132	0.025	0
2002	0.292	0.140	0	0.234	0.102	0	0.058	0.038	0
2003	0.808	0.128	1	0.619	0.089	1	0.189	0.039	0
Pine Mountain Wilderness									
	Baseline			DSI			Improvement from Baseline		
Year	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv
2001	1.001	0.088	1	0.832	0.068	1	0.169	0.020	0
2002	0.329	0.150	0	0.268	0.108	0	0.061	0.042	0
2003	0.867	0.122	2	0.674	0.095	1	0.193	0.027	1
Sierra Ancha Wilderness									
	Baseline			DSI			Improvement from Baseline		
Year	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv
2001	0.328	0.063	0	0.253	0.042	0	0.075	0.021	0
2002	0.196	0.101	0	0.153	0.071	0	0.043	0.030	0
2003	0.278	0.102	0	0.192	0.065	0	0.086	0.037	0
Superstition Wilderness									
	Baseline			DSI			Improvement from Baseline		
Year	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv
2001	0.241	0.071	0	0.185	0.047	0	0.056	0.024	0
2002	0.233	0.117	0	0.185	0.085	0	0.048	0.032	0
2003	0.180	0.105	0	0.131	0.070	0	0.049	0.035	0
Sycamore Canyon Wilderness									
	Baseline			DSI			Improvement from Baseline		
Year	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv
2001	0.322	0.178	0	0.254	0.138	0	0.068	0.040	0
2002	0.470	0.202	0	0.393	0.169	0	0.077	0.033	0
2003	0.513	0.271	1	0.447	0.199	0	0.066	0.072	1
Zion NP									
	Baseline			DSI			Improvement from Baseline		
Year	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv
2001	0.977	0.220	2	0.811	0.190	1	0.166	0.030	1
2002	0.569	0.156	1	0.502	0.135	1	0.067	0.021	0
2003	0.843	0.256	2	0.676	0.204	1	0.167	0.052	1

Table 6-9. Visibility Improvement Predicted for Using a Lower Sulfur Fuel Blend

	Baseline			Fuel Switching			Improvement from Baseline		
Year	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv	Max Δdv	98th Percentile Δdv	# of Days Over 0.5 Δdv
Bryce Canyon NP									
2001	0.472	0.121	0	0.425	0.114	0	0.047	0.007	0
2002	0.291	0.131	0	0.267	0.122	0	0.024	0.009	0
2003	0.446	0.182	0	0.392	0.145	0	0.054	0.037	0
Grand Canyon NP									
2001	1.604	0.849	28	1.533	0.787	24	0.071	0.062	4
2002	2.684	0.996	36	2.619	0.930	35	0.065	0.066	1
2003	2.068	1.586	47	2.014	1.480	45	0.054	0.106	2
Joshua Tree NP									
2001	0.462	0.201	0	0.391	0.174	0	0.071	0.027	0
2002	0.330	0.174	0	0.288	0.143	0	0.042	0.031	0
2003	0.266	0.130	0	0.218	0.103	0	0.048	0.027	0
Mazatzal Wilderness									
2001	0.685	0.088	1	0.608	0.072	1	0.077	0.016	0
2002	0.292	0.140	0	0.257	0.118	0	0.035	0.022	0
2003	0.808	0.128	1	0.699	0.102	1	0.109	0.026	0
Pine Mountain Wilderness									
2001	1.001	0.088	1	0.903	0.074	1	0.098	0.014	0
2002	0.329	0.150	0	0.293	0.126	0	0.036	0.024	0
2003	0.867	0.122	2	0.755	0.105	2	0.112	0.017	0
Sierra Ancha Wilderness									
2001	0.328	0.063	0	0.285	0.053	0	0.043	0.010	0
2002	0.196	0.101	0	0.171	0.090	0	0.025	0.011	0
2003	0.278	0.102	0	0.228	0.080	0	0.050	0.022	0
Superstition Wilderness									
2001	0.241	0.071	0	0.209	0.057	0	0.032	0.014	0
2002	0.233	0.117	0	0.205	0.099	0	0.028	0.018	0
2003	0.180	0.105	0	0.151	0.083	0	0.029	0.022	0
Sycamore Canyon Wilderness									
2001	0.322	0.178	0	0.282	0.153	0	0.040	0.025	0
2002	0.470	0.202	0	0.425	0.179	0	0.045	0.023	0
2003	0.513	0.271	1	0.471	0.225	0	0.042	0.046	1
Zion NP									
2001	0.977	0.220	2	0.881	0.203	1	0.096	0.017	1
2002	0.569	0.156	1	0.530	0.147	1	0.039	0.009	0
2003	0.843	0.256	2	0.746	0.226	1	0.097	0.030	1

6.6. PROPOSED BART CONTROL AND EMISSION LEVELS

As discussed previously, there is considerable uncertainty on the SO_2 reduction that can be expected for the Nelson lime kilns based on switching to a lower sulfur fuel blend or using a DSI system. LNA has assumed a 40% reduction attributable to DSI based on limited testing conducted in June 2013 at the Nelson Plant. The cost for a DSI system using Sorbacal® SPS is between \$5,000/ton and \$5,300/ton (See Table 6-5) and approximately \$51 million/Δdv. The cost for a DSI system using SBC is between \$5,300/ton and \$5,500/ton (See Table 6-6) and approximately \$53 million /Δdv. LNA estimated a 23.3% reduction attributable to fuel switching The cost for fuel switching is approximately \$1,100/ton (see Table 6-7) and approximately \$10 million/Δdv.

LNA believes that the cost of DSI is excessive, both on a dollar per ton basis and on a dollar per deciview improvement basis. Typically, when the cost of a more efficient technology is deemed excessive, the next most efficient technology that is not cost prohibitive would be selected as BART. This would suggest switching to a lower sulfur fuel blend would constitute BART for SO_2 for the Nelson lime kilns. LNA has determined that BART is a 23.3% reduction in SO_2 that will be achieved through the use of a lower sulfur fuel blend. Thus, LNA proposes that BART for SO_2 for Kiln 1 is 9.32 lb/ton of lime, applicable on a 30 day rolling average as demonstrated through the use of a CEMS. LNA also proposes that BART for SO_2 for Kiln 2 is 9.73 lb/ton of lime, applicable on a 30 day rolling average as demonstrated through the use of a CEMS.

Because of the uncertainties about whether fuel switching alone will be sufficient, LNA requests that it be given flexibility to use that combination of fuel switching and add on controls that achieves the proposed BART limits for Kilns 1 and 2, consistent with any applicable preconstruction permit requirements. This determination provides LNA some flexibility to adjust its operations to ensure that the BART limit is achieved.

7. PM BART EVALUATION

Particulate matter is generated from fuel combustion and other processes that occur in a lime kiln.

The baseline PM emission factors that were determined from stack testing reflecting filterable PM for Kilns 1 and 2 are shown in Table 5-1.

Table 7-1. Baseline PM Emission Factors

Unit	PM Emission Factor (lb/ton lime)
Kiln 1	0.063
Kiln 2	0.082

A comparison of Table 7-1 above with Table 5-1 and Table 6-1 of this report shows that the baseline PM emissions for the kilns are much lower than the baseline emissions of SO_2 and NO_x for the kilns. The low PM emissions correspond to low visibility impacts attributable to PM when compared to the impacts attributable to SO_2 (as sulfates) and NO_x, (as nitrates), as shown in Table 4-7 of this report.

Both kilns currently have existing baghouses for particulate matter control. A baghouse is the most efficient device for controlling particulate matter from this type of source. Since there are no particulate control devices that are more effective than the existing baghouses, LNA proposes that the existing baghouses constitute BART for the kilns. Further, LNA proposes to comply with a BART emission limit for both kilns that is equal to the PM limit for existing lime kilns that is included in the EPA's Maximum Achievable Control Technology (MACT) standard that applies to the kilns (0.12 lbs PM/ton of stone feed).[10] Since LNA is proposing to use the most effective particulate control devices on the two kilns, there is no need to evaluate other impacts in establishing these control technologies as BART.

[10] Should EPA revise the PM limit for existing sources in the MACT standard, LNA proposes to comply with the revised limit.

APPENDIX A: SUMMARY OF RBLC SEARCH RESULTS FOR NO_X

RBLCID	FACILITY_NAME	FACILITY_STATE	PERMIT_NUM	PERMIT_ISSUANCE_DATE	PROCESS_NAME	PROCCESS_TYPE	THROUGHPUT	THROUGHPUT_UNIT	POLLUTANT	CONTROL_METHOD_CODE	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT	EMISSION_LIMIT_1_AVG_TIME_CONDITION
AR-0082	ARKANSAS LIME COMPANY	AR	0045-AOP-R3	8/30/2005	LIME KILN, SN-30Q	90.019	45254	T/YR	Nitrogen Oxides (NOx)	N		3.5	LB/T	LB/TON OF LIME, 30 DAY ROLLING AVERAGE
MI-0383	WESTERN LIME CORPORATION	MI	26-04	1/30/2004	LIME KILN	90.019	186.3	MMBTU/H	Nitrogen Dioxide (NO2)	P	LOW-NOX BURNERS AND LIMIT EXCESS AIR	132.6	LB/H	
OH-0270	CARMEUSE LIME - MAPLE GROVE FACILITY	OH	03-13527	10/14/2003	ROTARY KILN (2)	90.019	650	T/D	Nitrogen Oxides (NOx)	N		1234.9	LB/H	FOR EACH KILN
OH-0321	MARTIN MARIETTA MATERIALS	OH	03-17089	11/13/2008	ROTARY LIME KILN	90.019	18000	LB/H	Nitrogen Oxides (NOx)	N		673.43	T/YR	PER ROLLING 12-MONTH PERIOD
PA-0241	GRAYMONT BELLEFONTE PLANT	PA	14-00002A	7/9/2004	# 7 LIME KILN	90.019	1050	T/D	Nitrogen Oxides (NOx)	N		709	T/YR	12 MONTH ROLLING AVG
*PA-0283	GRAYMONT PA INC/PLEASANT GAP & BELLEFONTE PLTS	PA	14-00002N	11/19/2012	KILN NO. 8	90.019	0		Nitrogen Oxides (NOx)	N		7.9	LB/HR	ROLLING 30-DAY AVERAGE
TX-0452	AUSTIN WHITE LIME COMPANY MCNEIL PLANT & QUARRY	TX	P114M3	11/19/2003	KILN NO 1 AND 2	90.019			Nitrogen Oxides (NOx)	A	THE KILNS ARE CONTROLLED WITH EITHER A CYCLONE/WET SCRUBBER COMBO	106.1	LB/H	
TX-0452	AUSTIN WHITE LIME COMPANY MCNEIL PLANT & QUARRY	TX	P114M3	11/19/2003	KILN NO 3	90.019			Nitrogen Oxides (NOx)	P	THE KILNS ARE CONTROLLED WITH EITHER A CYCLONE/BAGHOUSE COMBO	118.3	LB/H	
WI-0233	CLM - SUPERIOR	WI	05-DCF-412	8/16/2006	LIME KILN (P50)	90.019	650	T/D	Nitrogen Oxides (NOx)	P	USE OF A PREHEATER TYPE ROTARY KILN AND GOOD COMBUSTION PRACTICES / OPTIMIZATION WHICH MINIMIZE NITROGEN OXIDE EMISSIONS (WHILE MAINTAINING COMPLIANCE WITH CO LIMIT)	98.8	LB/H	3 HOUR AVG

APPENDIX B: SUMMARY OF JUNE 2013 DSI TESTING AT NELSON PLANT

LNA conducted trial runs of DSI on both of the Nelson kilns in June of 2013 to evaluate the impact of DSI on the SO_2 emission rates. The trial runs evaluated use of both standard hydrated lime manufactured at the Nelson Plant as well as Sorbacal® SPS brought in from LNA's St. Genevieve Plant in Missouri. To determine baseline conditions and injection control efficiencies during the testing, LNA operated continuous emission monitoring systems (CEMS) on both kilns to measure SO_2 emissions from the kiln stacks.

The injection of standard hydrated lime into the Kiln 2 ductwork between the preheater and baghouse (temperatures of 470°F to 480°F) over seven test periods ranging from 13 to 77 minutes covering a total of 4.5 hours, resulted in average control efficiencies of 0% to 46% under average injection rates of 500 lbs/hr to 3,700 lbs/hr. Based on the relatively high injection rate of lime required to achieve significant SO_2 reductions, no further injection tests using standard hydrated lime were performed.

Sorbacal® SPS was then injected into the Kiln 2 ductwork at the same point as the standard hydrated lime over five test periods covering 3.5 hours. The average control efficiencies measured over the five test periods were generally in the mid-40% range with average injection rates near 1,000 lbs/hr. A mid 60% average control efficiency was achieved over a 20-minute period but the average injection rate exceeded 1,800 lbs/hr. One test period covering 35 minutes, during which the kiln gas stream carbon monoxide (CO) levels were purposely increased, resulted in an average control efficiency of 48% but the average Sorbacal® SPS injection rate exceeded 2,000 lbs/hr.

Sorbacal® SPS was then injected into Kiln 2 above the preheater where temperatures ranged between 550°F and 570°F. Over two test periods covering 1 hour, the highest average control efficiency was 30% at an injection rate of nearly 1,500 lbs/hr. Consequently, this injection point was not evaluated further. The injection location was then moved back to between the preheater and baghouse. This location produced mixed results. The first test over a 27-minute time period resulted in an average control efficiency of 17% at an injection rate of over 1,000 lbs/hr. A follow up test over a 1.5-hour time period resulted in a 64% control efficiency; however, the injection rates could not be confirmed because of problems encountered with the injection feeders.

Kiln 1 was tested on the final day using Sorbacal® SPS injected into the ductwork between the preheater and baghouse. The first two test periods were conducted over 1.5 hours at low injection rates (< 500 lbs/hr) which resulted in average control efficiencies of 19% and 25%, respectively. The exact injection rates could not be confirmed due to computer problems. During the next testing period of 19 minutes, the average control efficiency was 43% at an average injection rate of over 1,100 lbs/hr.

Additional testing on Kiln #1 was conducted under stable combustion conditions with stack CO concentrations in the range of 50 to 90 parts per million. Under these low CO conditions, average injection rates of 1128, 1856, 2245 and 1794 lbs/hr were tested over durations of 37, 23, 16 and 30 minutes, respectively. Over these testing periods, the average control efficiencies were 43, 51, 71, 77 and 69%, respectively. Calculated on a 1-minute basis, the control efficiencies were highly variable, ranging from a low of 33% to a high of 84%. These results demonstrate that higher control efficiencies require extremely high injection rates.

Overall, results of the testing indicate that DSI using Sorbacal® SPS results in control efficiencies that are highly variable and dependent upon injection rates, injection location temperatures, and resident time of the sorbent in the gas stream. The results also indicate that kiln operations, especially whether the kiln is operating under high versus low CO conditions (i.e., oxygen deficient versus oxygen rich combustion conditions) affect the SO_2 emission rate and the resulting control efficiency of the sorbent. Unfortunately, operation at low CO conditions on a consistent basis, which appears to produce higher control efficiencies of the sorbent, is generally not possible, especially on Kiln 2 which was originally designed to produce lime for the steel industry where a strongly reducing (e.g., high CO) environment is needed to achieve product quality objectives. Other variables also affect CO operating levels, such as fuel quality, stone quality, ball mill levels, excess air conditions and the amount of pre-heater blockage, to name a few. In light of these limitations, 40% is likely the maximum consistently achievable value.

In conclusion, even though the testing was of a very limited duration and the results were highly variable, the test data suggest that a 40% reduction is likely achievable based on the use of Sorbacal® SPS or similarly performing sorbent. Due to normal variations in fuel sulfur input, kiln operating conditions and sorbent injection rates, a sorbent to SO_2 mass ratio of approximately 9:1 may be required to achieve SO_2 controls in the range of 20 to 40%.

APPENDIX E : NELSON SNCR CONFIGURATION