



REASONABLE PROGRESS FOUR-FACTOR  
ANALYSIS  
GRAYMONT WESTERN US INC.> Cricket Mountain, UT



Prepared By:

Anna Henolson – Managing Consultant  
Sam Najmolhoda – Associate Consultant  
John Goetze – Associate Consultant

**TRINITY CONSULTANTS**  
20819 72<sup>nd</sup> Avenue South  
Suite 610  
Kent, WA 98032  
(253) 867-5600

April 2020

Project 204801.0003

Trinity   
Consultants

*Environmental solutions delivered uncommonly well*

## TABLE OF CONTENTS

1. EXECUTIVE SUMMARY	1-1
2. INTRODUCTION AND BACKGROUND	2-1
3. SOURCE DESCRIPTION	3-1
4. EXISTING EMISSIONS	4-1
5. NO <sub>x</sub> FOUR FACTOR EVALUATION	5-1
5.1. STEP 1: Identification of Available Retrofit NO <sub>x</sub> Control Technologies	5-1
5.1.1. Combustion Controls	5-2
5.1.1.1. Reduce Peak Flame Zone Temperature	5-2
5.1.1.2. Low NO <sub>x</sub> Burners	5-2
5.1.1.3. Preheater Kiln Design/ Proper Combustion Practices	5-2
5.1.2. Post Combustion Controls	5-2
5.1.2.1. Selective Catalytic Reduction	5-2
5.1.2.2. Selective Non-Catalytic Reduction	5-3
5.2. STEP 2: Eliminate Technically Infeasible NO <sub>x</sub> Control Technologies	5-4
5.2.1. Combustion Controls	5-4
5.2.1.1. Reduce Peak Flame Zone Temperature	5-4
5.2.1.2. Low NO <sub>x</sub> Burners	5-4
5.2.1.3. Preheater Kiln Design/Proper Combustion Practices	5-4
5.2.2. Post Combustion Controls	5-5
5.2.2.1. Selective Catalytic Reduction	5-5
5.2.2.2. Selective Non-Catalytic Reduction	5-6
5.3. STEP 3: Rank of Technically Feasible NO <sub>x</sub> Control Options by Effectiveness	5-9
5.4. STEP 4: Evaluation of Impacts for Feasible NO <sub>x</sub> Controls	5-10
5.4.1. Cost of Compliance	5-10
5.4.2. Timing for Compliance	5-11
5.4.3. Energy Impacts and Non-Air Quality Impacts	5-11
5.4.4. Remaining Useful Life	5-11
5.5. NO <sub>x</sub> Conclusion	5-11
6. CONCLUSION	6-1
APPENDIX A : RBLC SEARCH RESULTS	A-1
APPENDIX B : NO <sub>x</sub> CONTROL COST CALCULATIONS	B-1

## LIST OF FIGURES

---

Figure 5-1. Preheater – Cross Section	5-6
Figure 5-2. Preheater Stone Chamber Temperature Variation with Time and Location	5-7

## LIST OF TABLES

---

Table 1-1. Potential Control Technologies	1-2
Table 3-1. Kiln Production Rates	3-1
Table 4-1. Baseline NO <sub>x</sub> Emission Rates	4-1
Table 5-1. Available NO <sub>x</sub> Control Technologies for Cricket Mountain Kilns 1-5	5-1
Table 5-2. Ranking of NO <sub>x</sub> Control Technologies by Effectiveness	5-10
Table 5-3. SNCR Cost Calculation Summary	5-11

## 1. EXECUTIVE SUMMARY

---

This report documents the results of a four-factor control analysis of the five lime kilns at the Graymont Western US Inc. (Graymont) Cricket Mountain lime plant, which is located near Delta, Utah. All five kilns are rotary, preheater type kilns that can produce approximately 600 – 1400 tons per day of lime, each. This report is provided in response to the Utah Department of Environmental Quality (DEQ) request made verbally to Graymont in December 2019.

Graymont was not identified as an eligible facility for the best available retrofit technology (BART) program during the first round of regional haze as it was built after August 7, 1977. DEQ has identified the Cricket Mountain plant as an eligible source for the regional haze program reasonable progress analysis based on a screening process that takes into account both the quantity of emissions from the facility and the proximity to the Class I areas protected by the regional haze program.

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

The purpose of this report is to provide information to DEQ regarding potential NO<sub>x</sub> emission reduction options for the Graymont Cricket Mountain lime kilns. Based on the Regional Haze Rule, associated EPA guidance, and DEQ's request, Graymont understands that DEQ will only move forward with requiring emission reductions from the Graymont Cricket Mountain kilns if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost effective controls among all options available to DEQ. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

The report identifies several potential control technologies for the Graymont lime kilns, as summarized in Table 1-1 below.

**Table 1-1. Potential Control Technologies**

<b>Pollutant</b>	<b>Emission Reduction Measure</b>	<b>Technically Feasible?</b>	<b>Cost Effective?</b>	<b>Appropriate for Emissions Reduction?</b>	<b>Notes</b>
NO <sub>x</sub>	Reduce Peak Flame Zone Temperature	No	N/A	No	Kiln must achieve sufficient peak flame temperature for proper calcination of limestone.
	Low NO <sub>x</sub> Burners (LNB)	Yes	Yes	Yes	Already installed and operating.
	Proper Kiln Operation	Yes	Yes	Yes	Proper kiln operation is technically feasible and currently employed at this facility.
	Preheater Kiln Design	Yes	Yes	Yes	The kilns currently feature a preheater.
	Selective Catalytic Reduction (SCR)	No	N/A	No	SCR is largely unproven on lime kilns, as there is no documented instance of this technology in the industry.
	Selective Non-Catalytic Reduction (SNCR)	No	No	No	There is only one RBLC entry for a lime kiln installing SNCR, and the details of its installation remain private. Even if feasible, SNCR is also not cost effective for Cricket Mountain.

It is also worth noting that these five lime kilns were all permitted under EPA’s PSD program and were determined to meet BACT at the time those permits were issued and the sources constructed. Furthermore, the NO<sub>x</sub> controls that the Cricket Mountain kilns currently utilize are consistent with recent BACT determinations for new rotary preheater lime kilns.<sup>1</sup> Graymont expects that control programs under the current regional haze efforts will not go beyond BACT.

This report outlines Graymont’s evaluation of possible options for reducing the emissions of NO<sub>x</sub> at its Cricket Mountain facility near Delta, Utah. There are currently no technically feasible and cost effective reduction options available beyond current best practices for the Graymont facility. Therefore, the baseline emissions provided in this analysis are expected to be the same as those of the “control scenario” for the Graymont Cricket Mountain facility.

---

<sup>1</sup> See Appendix A, the RBLC Search Results, for a list of recent BACT determinations.

## 2. INTRODUCTION AND BACKGROUND

---

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

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. In establishing a reasonable progress goal for a Class I area, the state must (40 CFR 51.308(d)(i)):

- (A) consider the costs of compliance, the time necessary for compliance, the energy and non-air quality environmental impacts of compliance, and the remaining useful life of any potentially affected sources, and include a demonstration showing how these factors were taken into consideration in selecting the goal.*
- (B) Analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064. To calculate this rate of progress, the State must compare baseline visibility conditions to natural visibility conditions in the mandatory Federal Class I area and determine the uniform rate of visibility improvement (measured in deciviews) that would need to be maintained during each implementation period in order to attain natural visibility conditions by 2064. In establishing the reasonable progress goal, the State must consider the uniform rate of improvement in visibility and the emission reduction.*

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

DEQ requested Graymont’s assistance in developing a four-factor analysis of potential emission reduction options for NO<sub>x</sub> at the Cricket Mountain facility. Graymont understands that the information provided in a four-factor review of control options will be used by EPA in their evaluation of reasonable progress goals for Utah. The purpose of this report is to provide information to DEQ regarding potential NO<sub>x</sub> emission reduction options for the Graymont Cricket Mountain lime kilns. Based on the Regional Haze Rule, associated EPA guidance, and DEQ’s request, Graymont understands that DEQ will only move forward with requiring emission reductions from the Graymont Cricket Mountain lime kilns if the emission reductions can be demonstrated to be needed to show reasonable progress and provide the most cost effective controls among all options available to DEQ. In other words, control options are only relevant for the Regional Haze Rule if they result in a reduction in the existing visibility impairment in a Class I area needed to meet reasonable progress goals.

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

- Factor 1. Costs of compliance
- Factor 2. Time necessary for compliance
- Factor 3. Energy and non-air quality environmental impacts of compliance

#### Factor 4. Remaining useful life of the kilns

Factors 1 and 3 of the four factors that are listed above are considered by conducting a step-wise review of emission reduction options in a top-down fashion similar to the top-down approach that is included in the EPA RHR guidelines<sup>2</sup> for conducting a review of Best Available Retrofit Technology (BART) for a unit<sup>3</sup>. These steps are as follows:

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

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

A review of the four factors for NO<sub>x</sub> can be found in Sections 5 this report. Section 4 of this report includes information on the Graymont Cricket Mountain kilns' existing/baseline emissions.

---

<sup>2</sup> The BART provisions were published as amendments to the EPA's RHR in 40 CFR Part 51, Section 308 on July 5, 2005.

<sup>3</sup>References to BART and BART requirements in this Analysis should not be construed as an indication that BART is applicable to the Graymont Cricket Mountain facility.



### 3. SOURCE DESCRIPTION

---

The Graymont Western US, Inc. Cricket Mountain Plant is located in Millard County, Utah, approximately 30 miles southwest of Delta. The nearest Class I area to the plant is the Capitol Reef National Park. It is approximately 81 miles (131 kilometers) southeast of the Cricket Mountain plant.

The facility operates five horizontal rotary preheater lime kilns. The five kilns are nearly identical in design and operations, although the production rates for each kiln vary.

**Table 3-1. Kiln Production Rates**

<b>Kiln</b>	<b>Nominal Lime Production (tons/day)</b>
1	600
2	600
3	840
4	1,266
5	1,400

All five kilns use coal as a primary fuel source. Typical annual fuel usage rates for the five kilns combined are approximately 180,000 tons per year of coal (based on 2014 operation and 11,400 Btu/lb). Fuels typically used for kiln startup include diesel and propane. Natural gas is not available at the plant.

Further details of the fuel throughputs and emission rates are provided in Section 4.

## 4. EXISTING EMISSIONS

---

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

Baseline annual emissions for NO<sub>x</sub> are calculated based on stack test data and annual production rates and are consistent with annual emission inventory reports. For the purposes of this regional haze four-factor analysis, the baseline emissions for the Graymont Cricket Mountain kilns are the average NO<sub>x</sub> emissions for the years 2014-2018, which are summarized in Table 4-1 below.

**Table 4-1. Baseline NO<sub>x</sub> Emission Rates**

<b>Kiln</b>	<b>NO<sub>x</sub> Baseline Emission Rate <sup>a</sup> (ton/yr)</b>
1	85.5
2	60.3
3	50.0
4	107.1
5	336.1
Total	639.0

<sup>a</sup> Baseline emissions are the average NO<sub>x</sub> emissions for years 2014-2018, based on stack test data and annual production rates.

## 5. NO<sub>x</sub> FOUR FACTOR EVALUATION

---

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

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

Cost (Factor 1) and energy / non-air quality impacts (Factor 3) are key factors determined in Step 4 of the step-wise review. However, timing for compliance (Factor 2) and remaining useful life (Factor 4) are also discussed in Step 4 to fully address all four factors as part of the discussion of impacts. Factor 4 is primarily addressed in the context of the costing of emission reduction options and whether any capitalization of expenses would be impacted by a limited equipment life.

The baseline NO<sub>x</sub> emission rates that are used in the NO<sub>x</sub> four-factor analysis are summarized in Table 4-1. The basis of the emission rates is provided in Section 4 of this report. The kilns currently utilize low-NO<sub>x</sub> burners (LNB), as described in Section 5.1.1.2, below.

### 5.1. STEP 1: IDENTIFICATION OF AVAILABLE RETROFIT NO<sub>x</sub> CONTROL TECHNOLOGIES

NO<sub>x</sub> is produced during fuel combustion when nitrogen contained in the fuel and combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms “thermal” NO<sub>x</sub> and “fuel” NO<sub>x</sub> when describing NO<sub>x</sub> emissions from the combustion of fuel. Thermal NO<sub>x</sub> emissions are produced when elemental nitrogen in the combustion air is oxidized in a high temperature zone. Fuel NO<sub>x</sub> emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

Most of the NO<sub>x</sub> formed within a rotary lime kiln is classified as thermal NO<sub>x</sub>. Virtually all of the thermal NO<sub>x</sub> is formed in the region of the flame at the highest temperatures, approximately 3,000 to 3,600 degrees Fahrenheit (°F). A small portion of NO<sub>x</sub> is formed from nitrogen in the fuel that is liberated and reacts with the oxygen in the combustion air.

Step 1 of the top-down control review is to identify available retrofit control options for NO<sub>x</sub>. The available NO<sub>x</sub> retrofit control technologies for the Cricket Mountain kilns are summarized in Table 5-1.

**Table 5-1. Available NO<sub>x</sub> Control Technologies for Cricket Mountain Kilns 1-5**

<b>NO<sub>x</sub> Control Technologies</b>	
Combustion Controls	Reduce Peak Flame Zone Temperature Low NO <sub>x</sub> Burners (LNB) Proper Kiln Operation Preheater Kiln Design
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

NO<sub>x</sub> emissions controls, as listed in Table 5-1, can be categorized as combustion or post-combustion controls. Combustion controls reduce the peak flame temperature and excess air in the kiln burner, which minimizes NO<sub>x</sub> formation. Post-combustion controls such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) convert NO<sub>x</sub> in the flue gas to molecular nitrogen and water.

### 5.1.1. Combustion Controls

#### 5.1.1.1. Reduce Peak Flame Zone Temperature

These are methods of reducing the temperature of combustion products in order to inhibit the formation of thermal NO<sub>x</sub>. They include (1) using fuel rich mixtures to limit the amount of oxygen available; (2) using fuel lean mixtures to limit amount of energy input; (3) injecting cooled, oxygen depleted flue gas into the combustion air; and (4) injecting water or steam.

#### 5.1.1.2. Low NO<sub>x</sub> Burners

LNBS reduce the amount of NO<sub>x</sub> initially formed in the flame. The principle of all LNBS is the same: 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 reduce thermal NO<sub>x</sub> formation by lowering flame temperatures. Control of air turbulence and speed is often controlled via mixing air fans. Some of the burner designs produce a low pressure zone at the burner center by injecting fuel at high velocities along the burner edges. Such a low pressure zone tends to recirculate hot combustion gas which is retrieved through an internal reverse flow zone around the extension of the burner centerline. The recirculated combustion gas is deficient in oxygen, thus producing the effect of flue gas recirculation. Reducing the oxygen content of the primary air creates a fuel-rich combustion zone that then generates a reducing atmosphere for combustion. Due to fuel-rich conditions and lack of available oxygen, formation of thermal NO<sub>x</sub> and fuel NO<sub>x</sub> are minimized<sup>4</sup>.

#### 5.1.1.3. Preheater Kiln Design/ Proper Combustion Practices

The use of staged combustion and preheating alone can lead to effective reduction of NO<sub>x</sub> emissions. By allowing for initial combustion in a fuel-rich, oxygen-depleted zone, necessary temperatures can be achieved without concern for the oxidation of nitrogen. This initial combustion is then followed by a secondary combustion zone that burns at a lower temperature, allowing for the addition of additional combustion air without significant formation of NO<sub>x</sub>.<sup>5</sup>

### 5.1.2. Post Combustion Controls

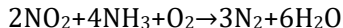
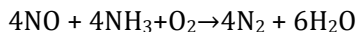
#### 5.1.2.1. Selective Catalytic Reduction

Selective catalytic reduction (SCR) is an exhaust gas treatment process in which ammonia (NH<sub>3</sub>) is injected into the exhaust gas upstream of a catalyst bed. On the catalyst surface, NH<sub>3</sub> and nitric oxide (NO) or nitrogen dioxide (NO<sub>2</sub>) react to form diatomic nitrogen and water. The overall chemical reactions can be expressed as follows:

---

<sup>4</sup> USEPA, Office of Air Quality Planning and Standards. Alternative Control Technologies Document – NO<sub>x</sub> Emissions from Cement Manufacturing. EPA-453/R-94-004, Page 5-5 to 5-8.

<sup>5</sup> Ibid, Page 58.

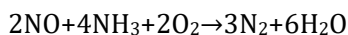


When operated within the optimum temperature range of 480°F to 800°F, the reaction can result in removal efficiencies between 70 and 90 percent.<sup>6</sup> The rate of NO<sub>x</sub> removal increases with temperature up to a maximum removal rate at a temperature between 700°F and 750°F. As the temperature increases above the optimum temperature, the NO<sub>x</sub> removal efficiency begins to decrease. As of this report, there are no known instances of SCRs installed on lime kilns.

#### 5.1.2.2. Selective Non-Catalytic Reduction

In SNCR systems, a reagent is injected into the flue gas within an appropriate temperature window. The NO<sub>x</sub> and reagent (ammonia or urea) react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three to four times as much reagent as SCR systems to achieve similar NO<sub>x</sub> reductions.

Like SCR, SNCR uses ammonia or a solution of urea to reduce NO<sub>x</sub> through a similar chemical reaction.



SNCR residence time can vary between 0.001 seconds and 10 seconds.<sup>7</sup> However, increasing the residence time available for mass transfer and chemical reactions at the proper temperature generally increases the NO<sub>x</sub> removal. There is a slight gain in performance for residence times greater than 0.5 seconds. The EPA Control Cost Manual indicates that SNCR requires a higher temperature range than SCR of between approximately 1,550°F and 1,950°F,<sup>8</sup> due to the lack of a catalyst to lower the activation energies of the reactions; however, the control efficiencies achieved by SNCR vary across that range of temperatures. That said, the effectiveness of SNCR on lime kilns is largely unproven. Lime kilns present unique technical challenges not experienced by cement kilns. While mid-kiln injection is often the most effective method of implementing SNCR on cement kilns, injection at that location is not feasible for a lime kiln. Lime kilns experience lower NO<sub>x</sub> concentrations at a given point in the kiln, have shorter residence times, and face issues in the stability of temperature profiles when compared to cement kilns. At higher temperatures, NO<sub>x</sub> reduction is less effective.<sup>9</sup> In addition, a greater residence time is required when operating at lower temperatures.

In cement kilns SNCR can be applied as a tailpipe technology or in a certain combustion zone of kilns to facilitate SNCR in a non-tailpipe mode (mid-kiln SNCR). However, there are important differences between and lime kiln and cement kiln that cause technical barriers to mid-kiln firing. The lime industry has a

---

<sup>6</sup> Air Pollution Control Cost Manual, Section 4, Chapter 2, Selective Catalytic Reduction, NO<sub>x</sub> Controls, EPA/452/B-02-001, Page 2-9 and 2-10.

<sup>7</sup> Air Pollution Control Cost Manual, Section 4, Chapter 1, Selective Non-Catalytic Reduction, NO<sub>x</sub> Controls, EPA/452/B-02-001, Page 1-8

<sup>8</sup> Ibid, Page 1-6

<sup>9</sup> USEPA, Office of Air Quality Planning and Standards. Alternative Control Technologies Document – NO<sub>x</sub> Emissions from Cement Manufacturing. EPA-453/R-94-004, Section 5.2.2, Page 5-21.

severely limited track record in determining the feasibility or control level that could be attained if mid-kiln SNCR were attempted on the Cricket Mountain kilns. The aforementioned technical barriers to SNCR implementation have limited the technology's use in the industry, with temperature, residence time, and lower NO<sub>x</sub> concentrations distinguishing lime production from the cement production process. The RACT/BACT/LAER Clearinghouse (RBLC) database includes only one instance of a lime kiln that was permitted with SNCR as control for NO<sub>x</sub> emissions.<sup>10</sup> The permit documents indicate that after conducting a trial with the SNCR, a lower limit would be established that takes into account the control of NO<sub>x</sub> emissions achieved by the SNCR (unless it is demonstrated to not provide effective control or result in unacceptable consequences). Updated permit files have not included a reduced permit limit, and there is no publicly available evidence of the trial results. Based on the record, the SNCR installation and reduction for this RBLC search result has not been demonstrated. Additionally, for the only other instances of known SNCR installations on different lime kilns (which do not appear in RBLC results), very limited information is available on the details of these kilns necessary for Graymont to evaluate whether the application of SNCR in that instance could be implemented at Cricket Mountain. Even though SNCR has not been demonstrated as a successful control option for NO<sub>x</sub> emissions from lime kilns, indicating the technology may not meet the criteria to be considered available, Graymont conservatively evaluates the technical feasibility further.

## 5.2. STEP 2: ELIMINATE TECHNICALLY INFEASIBLE NO<sub>x</sub> CONTROL TECHNOLOGIES

Step 2 of the top-down control review is to eliminate technically infeasible NO<sub>x</sub> control technologies that were identified in Step 1.

### 5.2.1. Combustion Controls

#### 5.2.1.1. Reduce Peak Flame Zone Temperature

In a lime kiln, product quality is co-dependent on temperature and atmospheric conditions within the system. Although low temperatures inhibit NO<sub>x</sub> formation, they also inhibit the calcination of limestone. For this reason, methods to reduce the peak flame zone temperature in a lime kiln burner are technically infeasible.

#### 5.2.1.2. Low NO<sub>x</sub> Burners

The facility currently operates low-NO<sub>x</sub> burners in the lime kilns. Coal is delivered to the burners using a direct fired system. However, to limit NO<sub>x</sub>, only enough primary air is used to sweep coal out of the mill. This is similar to using an indirect fired system, which also limits primary air to the burners while delivering fuels.

Baseline emissions are based on the operation of these low NO<sub>x</sub> burners. All alternative methods of NO<sub>x</sub> control in this analysis will assume that the kilns continue to operate these burners.

#### 5.2.1.3. Preheater Kiln Design/Proper Combustion Practices

Proper combustion practices and preheater kiln design are considered technically feasible for Graymont and will be considered further.

---

<sup>10</sup> RBLC Search results are provided in Appendix A, see the entry for the Mississippi Lime Company.

## 5.2.2. Post Combustion Controls

### 5.2.2.1. Selective Catalytic Reduction

Efficient operation of the SCR process requires fairly constant exhaust temperatures (usually  $\pm 200^\circ\text{F}$ ).<sup>11</sup> Fluctuation in exhaust gas temperatures reduces removal efficiency. If the temperature is too low, ammonia slip occurs. Ammonia slip is caused by low reaction rates and results in both higher  $\text{NO}_x$  emissions and appreciable ammonia emissions. If the temperature is too high, oxidation of the  $\text{NH}_3$  to  $\text{NO}$  can occur. Also, at higher removal efficiencies (beyond 80 percent), an excess of  $\text{NH}_3$  is necessary, thereby resulting in some ammonia slip. Other emissions possibly affected by SCR include increased PM emissions (as ammonia salts result from the reduction of  $\text{NO}_x$  and are emitted in a detached plume) and increased  $\text{SO}_3$  emissions (from oxidation of  $\text{SO}_2$  on the catalyst).

To reduce fouling the catalyst bed with the PM in the exhaust stream, an SCR unit can be located downstream of the particulate matter control device (PMCD). However, due to the low exhaust gas temperature exiting the PMCD (approximately  $350^\circ\text{F}$ ), a heat exchanger system would be required to reheat the exhaust stream to the desired reaction temperature range of between  $480^\circ\text{F}$  to  $800^\circ\text{F}$ . The source of heat for the heat exchanger would be the combustion of fuel<sup>12</sup>, with combustion products that would enter the process gas stream and generate additional  $\text{NO}_x$ . Therefore, in addition to storage and handling equipment for the ammonia, the required equipment for the SCR system will include a catalytic reactor, heat exchanger and potentially additional  $\text{NO}_x$  control equipment for the emissions associated with the heat exchanger fuel combustion.

High dust and semi-dust SCR technologies are still highly experimental. A high dust SCR would be installed prior to the dust collectors, where the kiln exhaust temperature is closer to the optimal operating range for an SCR. It requires a larger volume of catalyst than a tail pipe unit, and a mechanism for periodic cleaning of catalyst. A high dust SCR also uses more energy than a tail pipe system due to catalyst cleaning and pressure losses.

A semi-dust system is similar to a high dust system. However, the SCR is placed downstream of an ESP or cyclone.

The main concern with high dust or semi-dust SCR is the potential for dust buildup on the catalyst, which can be influenced by site specific raw material characteristics present in the facility's quarry, such as trace contaminants that may produce a stickier particulate than is experienced at sites where the technology is being demonstrated. This buildup could reduce the effectiveness of the SCR technology, and make cleaning of the catalyst difficult, resulting in kiln downtime and significant costs.<sup>13</sup>

No lime kiln in the United States is using any of these SCR technologies. For the technical issues noted above, tail pipe, high dust and semi-dust SCR's are considered technically infeasible at this time.

---

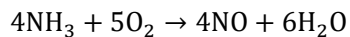
<sup>11</sup> Ibid, Page 2-11

<sup>12</sup> The fuel would likely be propane or diesel. There is no natural gas at the facility, and coal would require an additional dust collector.

<sup>13</sup> Preamble to NSPS subpart F, 75 FR 54970.

### 5.2.2.2. Selective Non-Catalytic Reduction

At temperatures above 2,100°F, NO<sub>x</sub> generation starts to occur as shown in the reaction below:

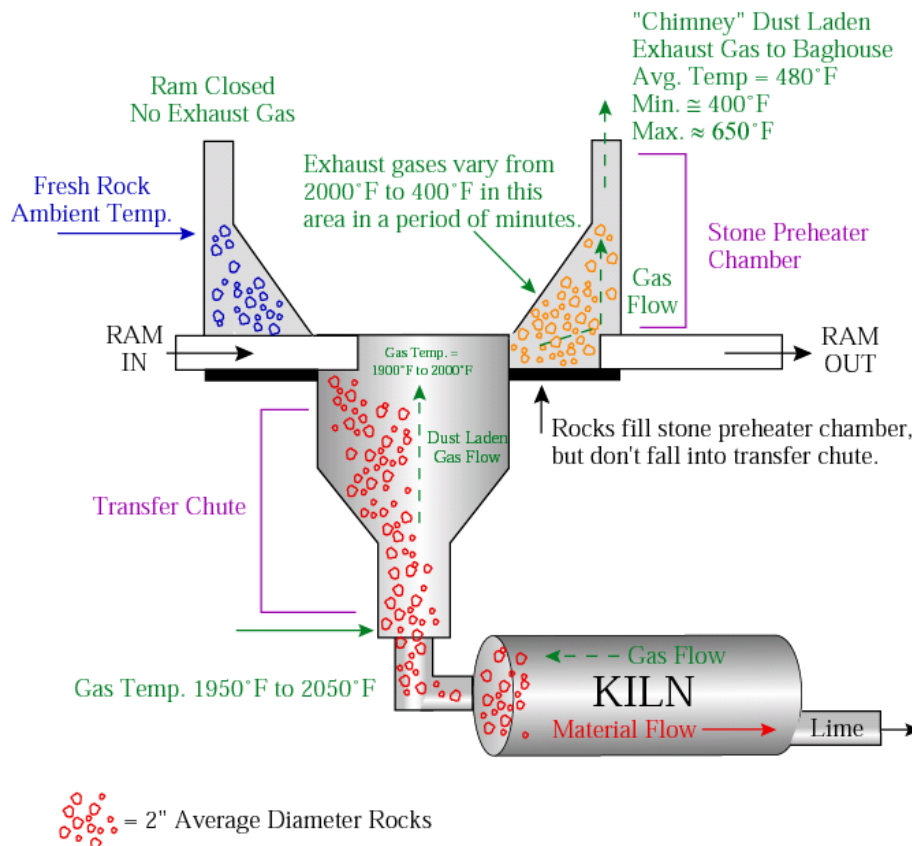


This reaction causes ammonia to oxidize and form NO instead of removing NO. When temperatures exceed 2200°F, NO formation dominates. This would likely be the case if ammonia were directly injected into the kiln tube. At temperatures below the required range, appreciable quantities of un-reacted ammonia will be released to the atmosphere via ammonia slip.

Based on the temperature profile, there are three locations in a rotary preheater lime kiln system where the ammonia /urea injection could theoretically occur: the stone/preheater chamber, the transfer chute, or after the PMCD. A fourth location that will be considered in this analysis is the kiln tube. In order for SNCR to be technically feasible, at least one of these locations must meet the following criteria: placement of injector to ensure adequate mixing of the ammonia or urea with the combustion gases, residence time of the ammonia with the combustion gases, and temperature profile for ammonia injection.

Figure 5-1 provides a schematic of a preheater/kiln system including typical process temperatures in the system.

**Figure 5-1. Preheater – Cross Section**



\*Figure represents a typical lime kiln preheater, and is not specific to the kilns at the Graymont Cricket Mountain facility

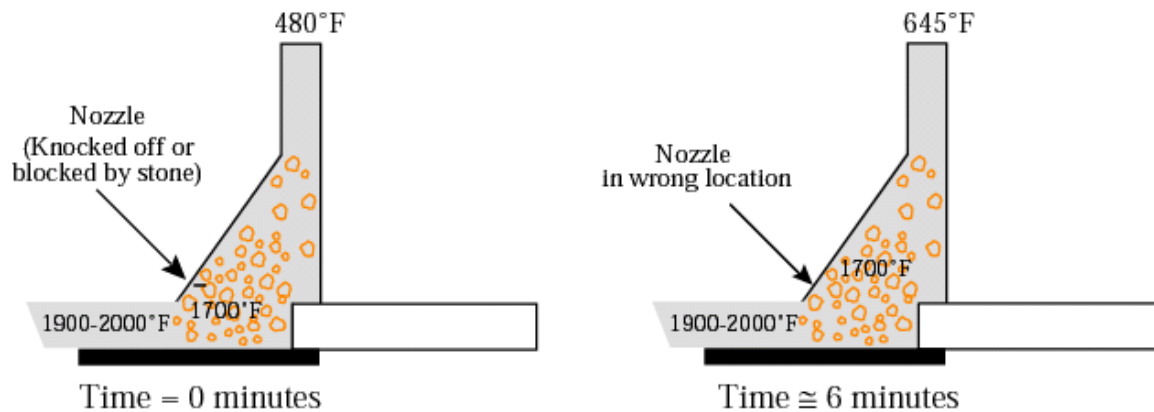


### *SNCR Ammonia/Urea Injection Location - Stone Chamber/Preheater*

The required temperature range for the reaction may occur within the preheater. However, the location of the temperature zone varies with time and location as explained below.

In each Graymont Cricket Mountain preheater, mechanical rams operate in sequence, transferring limestone, one ram at a time, from the stone chambers into the transfer chute. When a ram is in the “in” position, very little exhaust gas flows through the stone and out the duct. When the ram pulls out, the cold stone drops down and fills the stone heating chamber. The angle of repose of the stone and the configuration of the duct and chamber are such that stone does not continue to fall into the transfer chute. Hot gases, at approximately 1,950°F, then pass through the stone chamber filled with cold stone. The first gas to pass through the chamber exits the chimney at approximately 400°F. As the cold stone heats up, the exit gas temperature increases and reaches a high of approximately 600°F. The ram then strokes and pushes the heated stone into the transfer chute and starts the cycle again. The temperature profile in the stone chamber varies as shown in Figure 5-2.

**Figure 5-2. Preheater Stone Chamber Temperature Variation with Time and Location**



\*Figure represents a typical lime kiln preheater, and is not specific to the kilns at the Graymont Cricket Mountain facility

Besides the fact that the optimal temperature zone varies in location, the fact that the stone chamber is filled with stone makes using nozzles for injecting the ammonia/urea infeasible. For example, if a nozzle protruded from the wall of the stone chamber, the moving packed bed of rock would either knock it off or wear it off in a very short time. If the nozzle were inset into the wall of the chamber, the moving packed bed of stone would block the spray, and the ammonia or the urea mixture would simply coat a few of the stones, rather than mixing evenly throughout the gas stream. Similarly, if the nozzle were positioned at the roof of the preheater, the ammonia or urea would not be distributed throughout the gas stream. The preheater is approximately 75 percent full of stone, so ammonia or urea sprayed from the top of the preheater would have minimal residence time for distribution through the combustion gases before it would be blocked from distribution by the stone. Regardless of the choice of location for the nozzle, the ammonia or urea would not be effectively distributed through the large surface area of the preheater. These problems make application of SNCR in the stone chamber technically infeasible<sup>14</sup>.

<sup>14</sup> Report Concerning BACT for SO<sub>2</sub> and NO<sub>x</sub> for Proposed Lime Kiln,” prepared for Air Pollution Control Division, Clark County Health District, Las Vegas, Utah, April 1995.

#### *SNCR Ammonia/Urea Injection Location – Transfer Chute*

As shown in Figure 5-1, the temperature in the transfer chute is approximately 1,950°F for typical kilns. These temperatures are in the upper bound for the NO<sub>x</sub> reduction reaction. Temperatures this high reportedly resulted in approximately 30 percent NO<sub>x</sub> reduction in clean (non dust-laden) exhaust streams. Lime kilns do not have clean exhaust streams at this location. Rather, the back end of the transfer chute is an extremely dusty environment, and therefore the exhaust stream is dust-laden. The one SNCR installation in the lime industry has achieved control efficiencies of around 50% with the injection nozzles installed in the bottom of the preheater, at the preheater cone<sup>15</sup>. While this technology is certainly promising, this one example of SNCR installation on a rotary lime kiln does not necessarily transfer to other lime kilns. Effectiveness of SNCR is highly site-dependent, with a variety of factors having the potential to heavily influence the quantities of NO<sub>x</sub> controlled. Given the significant range (35-58%) of control efficiencies found for cement kilns, a control efficiency considerably lower than the average for cement of 40% is expected given ideal temperature scenarios (many kilns in the cement industry that utilize SNCR do so in the combustion zone in the calciner, where temperatures are lower than in the kiln). Lime kilns experience significant technical barriers to successful SNCR implementation not shared by the cement industry. When compared to the cement process, lower NO<sub>x</sub> concentrations, shorter residence times, and temperatures more frequently outside the optimal range for SNCR application yield lower control efficiencies for lime kilns. Therefore, a control efficiency of no more than 20% is anticipated for the Cricket Mountain kilns.

Locating an ammonia or urea injector nozzle in the chute to ensure mixing of the ammonia with the combustion gases would pose similar problems as the problems with the stone chamber location. Stones pour into the chute from the stone chamber, and in order to stabilize a nozzle for injection, the nozzle would need to be positioned out of the direct path of the flow of the stones. Further, the stone pieces that pour into the transfer chute from the chamber take up a large portion of the volume in the chute. Adequate mixing of the ammonia or urea with the combustion gases would be inhibited by the rock. The ammonia or urea would most likely end up on the stones, rather than mixing evenly throughout the gas stream.

The low percent NO<sub>x</sub> reduction combined with the uncertainty of the nozzle placement and mixing requirement eliminate the transfer chute as a technically feasible option for Cricket Mountain Kilns 1 through 5.

#### *SNCR Ammonia/Urea Injection Location - Inside Rotary Kiln*

Ammonia/urea could be injected through a door or port in the kiln shell. Similar to the transfer chute, stone is traveling down the rotary kiln. Consequently, the nozzle would need to be positioned out of the direct path of the flow of the stones. Theoretically, the temperature inside a rotary lime kiln, which is above 2,200 F, would promote the formation of NO from injected ammonia.

Graymont is aware that there have been trials at competing lime facilities with mid-kiln ammonia injection and transfer chute ammonia/urea injection for NO<sub>x</sub> reduction. However, the technology costs and technical details have not become publicly available, so Graymont cannot evaluate if the technology can be successfully applied specifically to the kilns at the Cricket Mountain facility.

Since a mid-kiln ammonia injection and transfer chute ammonia/urea injection systems would require extended trials to determine if the technology can effectively control NO<sub>x</sub> on the Graymont lime kilns, Graymont must conclude that this type of SNCR is not “available” with respect to the Cricket Mountain plant

---

<sup>15</sup> EPA Control Cost Manual, SNCR Cost chapter. 7<sup>th</sup> Edition, 2016. Page 1-7.  
<https://www3.epa.gov/ttn/ecas/docs/SNCRCostManualchapter7thEdition2016.pdf>

because it is not commercially available. Since it is not commercially available, no vendor performance guarantees can be made to its success. Therefore, this technology cannot be considered technically feasible.

The technology is not commercially available, as defined in 40 CFR Subpart 51, Appendix Y which states that:

*Two key concepts are important in determining whether a technology could be applied: “availability” and “applicability.” As explained in more detail below, a technology is considered “available” if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is “applicable” if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.*

Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:

*The typical stages for bringing a control technology concept to reality as a commercial product are:*

- *Concept stage;*
- *Research and patenting;*
- *Bench scale or laboratory testing;*
- *Pilot scale testing;*
- *Licensing and commercial demonstration; and*
- *Commercial sales.*

*A control technique is considered available, within the context presented above, if it has reached the stage of licensing and commercial availability. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as “available” for purposes of BART review.*

*Commercial availability by itself, however, is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or “applicable” to the source type under consideration.*

Though the technology is not considered technically feasible for Graymont’s Cricket Mountain facility for the reasons outlined above, cost calculations for the implementation of SNCR are included for completeness assuming a 20% control efficiency for NO<sub>x</sub>.

### **5.3. STEP 3: RANK OF TECHNICALLY FEASIBLE NO<sub>x</sub> CONTROL OPTIONS BY EFFECTIVENESS**

Step 3 of the top-down control review is to rank the technically feasible options to effectiveness. Table 5-2 presents potential NO<sub>x</sub> control technologies for the kilns and their associated control efficiencies.

**Table 5-2. Ranking of NO<sub>x</sub> Control Technologies by Effectiveness**

<b>Pollutant</b>	<b>Control Technology</b>	<b>Potential Control Efficiency (%)</b>
NO <sub>x</sub>	SNCR Low NO <sub>x</sub> Burner	20* Base case

\* 20% control efficiency is used for cost evaluation based on evaluation of feasibility of SNCR at another Graymont facility.

## 5.4. STEP 4: EVALUATION OF IMPACTS FOR FEASIBLE NO<sub>x</sub> CONTROLS

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

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

### 5.4.1. Cost of Compliance

In order to assess the cost of compliance for the installation of SNCR, the EPA Control Cost Manual is used. Capital costs for the installation of the SNCR assumed a 20-year life span for depreciation, as well as the current bank prime rate of 4.75% for interest calculations. The total capital investment includes the capital cost for the SNCR itself, the cost of the air pre-heater required (per the EPA Control Cost Manual, the air pre-heater will require modifications for coal-fired units when SO<sub>2</sub> control is necessary. This value is conservatively assumed for all coal-fired units evaluated for SNCR installation<sup>16</sup>), and the balance of the plant. Annual costs include both direct costs such as maintenance, reagent, electricity, water, fuel, and waste disposal cost and indirect costs for administrative charges and the amortized capital costs as a capital recovery value. A retrofit factor of 1.5 is used to account for the technical barriers described in section 5.2.2.1, including the existence of only one RBLC reference for an SNCR retrofit on a lime kiln, the difficulty of identifying an injection point that allows for ammonia to enter the gas stream within an optimal temperature window, the low residence times of lime kilns relative to cement kilns, and the relatively low inlet NO<sub>x</sub> concentrations that limit the effectiveness of the control technology. The total costs and cost effectiveness of control are summarized in Table 5-3, below.

---

<sup>16</sup> EPA Control Cost Manual, SNCR Cost chapter. 7<sup>th</sup> Edition, 2016. Page 1-44.  
<https://www3.epa.gov/ttn/ecas/docs/SNCRCostManualchapter7thEdition2016.pdf>

**Table 5-3. SNCR Cost Calculation Summary**

<b>Kiln</b>	<b>Total Capital Investment</b>	<b>Total Annual Cost</b>	<b>NO<sub>x</sub> Emissions Removed<sup>a</sup> (tpy)</b>	<b>Cost Effectiveness (\$/ton removed)</b>
1	\$5,425,232	\$519,152	15.5	\$33,571
2	\$5,817,345	\$552,963	10.9	\$50,720
3	\$6,482,717	\$616,847	9.0	\$68,276
4	\$7,927,545	\$755,901	19.4	\$39,025
5	\$7,547,629	\$741,500	60.8	\$12,199
<b>Total Project</b>	\$33,200,469	\$3,186,363	115.6	\$27,575

<sup>a</sup> Baseline NO<sub>x</sub> emissions are the average emissions from each kiln for the years 2014-2018.

#### 5.4.2. Timing for Compliance

Graymont believes that reasonable progress compliant controls are already in place. However, if DEQ determines SNCR is necessary to achieve reasonable progress, it is anticipated that this change could be implemented during the second planning period of regional haze (approximately ten years following EPA’s reasonable progress determination).

#### 5.4.3. Energy Impacts and Non-Air Quality Impacts

As previously stated, the cost of energy and water required for successful operation of the SNCR are included in the calculations, which can be found in detail in Appendix B. The installation is expected to decrease the efficiency of the overall facility, particularly as significant energy and water use is needed beyond current plan operation requirements.

#### 5.4.4. Remaining Useful Life

Graymont has assumed this control equipment will last for the entirety of the 20-year amortization period, which is reflected in the cost calculations.

### 5.5. NO<sub>x</sub> CONCLUSION

The facility currently uses low NO<sub>x</sub> burners in its five kilns to minimize NO<sub>x</sub> emissions. The use of low NO<sub>x</sub> burners is a commonly applied technology in current BACT determinations for new rotary preheater lime kilns today. The application of SCR has never been attempted on a lime kiln. SNCR has only one RBLC entry documenting implementation on a lime kiln. The use of these controls does not represent a cost effective control technology given the limited expected improvements to NO<sub>x</sub> emission rates, high uncertainty of successful implementation, high capital investment, and high cost per ton NO<sub>x</sub> removed.

## 6. CONCLUSION

---

This report outlines Graymont's evaluation of possible options for reducing the emissions of NO<sub>x</sub> at its Cricket Mountain facility near Delta, Utah. There are currently no technically feasible and cost effective reduction options available for the Graymont facility beyond current best practices. Therefore, the emissions for the 2028 on-the-books/on-the-way modeling scenario are expected to be the same as those used in the "control scenario" for the Graymont Cricket Mountain facility.

## APPENDIX A : RBLC SEARCH RESULTS

---

Table A-1. RBL Search Results

RBL ID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVERAGE TIME CONDITION	EMISSION LIMIT 2	EMISSION LIMIT 2 UNIT	EMISSION LIMIT 2 AVERAGE TIME CONDITION
IL-0117	MISSISSIPPI LIME COMPANY	MISSISSIPPI LIME COMPANY	IL	9/29/2015	Two Rotary Kilns	Coal; petroleum coke	50	tons lime/hour, each	Nitrogen Oxides (NOx)	Low excess air to minimize formation of NOx and selective non-catalytic reduction (SNCR) technology.	3.5	LBS/TON LIME PRODUCE	30-DAY ROLLING AVERAGE	2.61	LBS/TON LIME PRODUCE	12-MONTH ROLLING AVERAGE
TX-0726	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	2/22/2010	Rotary Kiln 2	natural gas, coal, and petroleum coke	504	tons per day	Nitrogen Oxides (NOx)		5	LB/TON OF LIME PROD		0		
TX-0726	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	2/22/2010	Rotary Kiln 3	natural gas, coal, and petroleum coke	850	tons per day	Nitrogen Oxides (NOx)		2.6	LB/TON OF LIME PROD		0		
WI-0250	GRAYMONT (WI) LLC	GRAYMONT (WI) LLC	WI	2/6/2009	P50 (S50). PREHEATER EQUIPPED, ROTARY LIME KILN	COAL	54	T/H STONE	Nitrogen Oxides (NOx)	GOOD COMBUSTION CONTROL, OPTIMIZATION	1.83	LB/T	24 HOUR AVG.	0.7	LB/MMBTU	MONTHLY AVG.
IL-0117	MISSISSIPPI LIME COMPANY	MISSISSIPPI LIME COMPANY	IL	9/29/2015	Two Rotary Kilns	Coal; petroleum coke	50	tons lime/hour, each	Sulfur Dioxide (SO2)	Natural absorptive capacity of lime kiln dust.	0.5	LBS/TON LIME	30-DAY ROLLING AVERAGE	0		
TX-0726	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	2/22/2010	Rotary Kiln 2	natural gas, coal, and petroleum coke	504	tons per day	Sulfur Dioxide (SO2)	Limiting the fuel sulfur input, in addition to the dry scrubbing inherent in these systems.	0			0		
TX-0726	ROTARY LIME KILN AND ASSOCIATED EQUIPMENT	CHEMICAL LIME, LTD	TX	2/22/2010	Rotary Kiln 3	natural gas, coal, and petroleum coke	850	tons per day	Sulfur Dioxide (SO2)	Limiting the fuel sulfur input, in addition to the dry scrubbing inherent in these systems.	0			0		
TX-0820	CLIFTON LIME PLANT	LHOIST NORTH AMERICA OF TEXAS, LTD.	TX	4/28/2017	lime kiln	coal	219000	t/yr	Sulfur Dioxide (SO2)	fuel sulfur limits	12.8	LB/TON LIME		0		
WI-0250	GRAYMONT (WI) LLC	GRAYMONT (WI) LLC	WI	2/6/2009	P50 (S50). PREHEATER EQUIPPED, ROTARY LIME KILN	COAL	54	T/H STONE	Sulfur Dioxide (SO2)	FUEL SULFUR LIMIT, INHERENT PROCESS COLLECTION OF SULFUR OXIDES.	0.62	LB/T	24 HOUR AVERAGE	2	PERCENT S	FUEL SULFUR LIMIT



APPENDIX B : NO<sub>x</sub> CONTROL COST CALCULATIONS

---

**Table B-1. Summary of SNCR Costs - Graymont Cricket Mountain**

<b>Kiln</b>	<b>Total Capital Investment</b>	<b>Annual Cost</b>	<b>Tons NO<sub>x</sub> In</b>	<b>Tons NO<sub>x</sub> Reduced</b>	<b>Cost Effectiveness (\$/ton reduced)</b>
1	\$5,425,232	\$519,152	85.5	15.5	\$33,571
2	\$5,817,345	\$552,963	60.3	10.9	\$50,720
3	\$6,482,717	\$616,847	50.0	9.0	\$68,276
4	\$7,927,545	\$755,901	107.1	19.4	\$39,025
5	\$7,547,629	\$741,500	336.1	60.8	\$12,199
Total	\$33,200,469	\$3,186,363	639	115.6	\$27,575

## Cost Estimate

Graymont Cricket Mountain Kiln 1

### Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ( $SNCR_{cost}$ ) =	\$1,439,111 in 2018 dollars
Air Pre-Heater Costs ( $APH_{cost}$ )* =	\$1,006,120 in 2018 dollars
Balance of Plant Costs ( $BOP_{cost}$ ) =	\$1,728,025 in 2018 dollars
<b>Total Capital Investment (TCI) =</b>	<b>\$5,425,232 in 2018 dollars</b>

\* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

### SNCR Capital Costs ( $SNCR_{cost}$ )

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ( $SNCR_{cost}$ ) =	\$1,439,111 in 2018 dollars
--	-----------------------------

### Air Pre-Heater Costs ( $APH_{cost}$ )\*

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs ( $APH_{cost}$ ) =	\$1,006,120 in 2018 dollars
---	-----------------------------

\* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

### Balance of Plant Costs ( $BOP_{cost}$ )

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs ( $BOP_{cost}$ ) =	\$1,728,025 in 2018 dollars
---	-----------------------------

## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$90,287 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$428,865 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$519,152 in 2018 dollars

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$81,378 in 2018 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$7,509 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$382 in 2018 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$57 in 2018 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$883 in 2018 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$79 in 2018 dollars
Direct Annual Cost =		\$90,287 in 2018 dollars

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$2,441 in 2018 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$426,423 in 2018 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$428,865 in 2018 dollars

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$519,152 per year in 2018 dollars
NOx Removed =	15 tons/year
Cost Effectiveness =	\$33,571.44 per ton of NOx removed in 2018 dollars

## Cost Estimate

Graymont Cricket Mountain Kiln 2

### Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ( $SNCR_{cost}$ ) =	\$1,513,946 in 2018 dollars
Air Pre-Heater Costs ( $APH_{cost}$ )* =	\$1,105,444 in 2018 dollars
Balance of Plant Costs ( $BOP_{cost}$ ) =	\$1,855,490 in 2018 dollars
<b>Total Capital Investment (TCI) =</b>	<b>\$5,817,345 in 2018 dollars</b>

\* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

### SNCR Capital Costs ( $SNCR_{cost}$ )

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ( $SNCR_{cost}$ ) =	\$1,513,946 in 2018 dollars
--	-----------------------------

### Air Pre-Heater Costs ( $APH_{cost}$ )\*

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs ( $APH_{cost}$ ) =	\$1,105,444 in 2018 dollars
---	-----------------------------

\* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

### Balance of Plant Costs ( $BOP_{cost}$ )

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs ( $BOP_{cost}$ ) =	\$1,855,490 in 2018 dollars
---	-----------------------------

## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$93,102 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$459,861 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$552,963 in 2018 dollars

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$87,260 in 2018 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$4,924 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$250 in 2018 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$37 in 2018 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$579 in 2018 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$51 in 2018 dollars
Direct Annual Cost =		\$93,102 in 2018 dollars

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$2,618 in 2018 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$457,243 in 2018 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$459,861 in 2018 dollars

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$552,963 per year in 2018 dollars
NOx Removed =	11 tons/year
Cost Effectiveness =	\$50,720.13 per ton of NOx removed in 2018 dollars

## Cost Estimate

Graymont Cricket Mountain Kiln 3

### Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ( $SNCR_{cost}$ ) =	\$1,693,923 in 2018 dollars
Air Pre-Heater Costs ( $APH_{cost}$ )* =	\$1,361,865 in 2018 dollars
Balance of Plant Costs ( $BOP_{cost}$ ) =	\$1,930,918 in 2018 dollars
<b>Total Capital Investment (TCI) =</b>	<b>\$6,482,717 in 2018 dollars</b>

\* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

### SNCR Capital Costs ( $SNCR_{cost}$ )

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ( $SNCR_{cost}$ ) =	\$1,693,923 in 2018 dollars
--	-----------------------------

### Air Pre-Heater Costs ( $APH_{cost}$ )\*

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs ( $APH_{cost}$ ) =	\$1,361,865 in 2018 dollars
---	-----------------------------

\* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

### Balance of Plant Costs ( $BOP_{cost}$ )

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs ( $BOP_{cost}$ ) =	\$1,930,918 in 2018 dollars
---	-----------------------------

## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =		\$104,388 in 2018 dollars
Indirect Annual Costs (IDAC) =		\$512,459 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC		\$616,847 in 2018 dollars

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	0.015 x TCI =	\$97,241 in 2018 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$6,025 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$306 in 2018 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$45 in 2018 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$708 in 2018 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$63 in 2018 dollars
Direct Annual Cost =		\$104,388 in 2018 dollars

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	0.03 x Annual Maintenance Cost =	\$2,917 in 2018 dollars
Capital Recovery Costs (CR)=	CRF x TCI =	\$509,542 in 2018 dollars
Indirect Annual Cost (IDAC) =	AC + CR =	\$512,459 in 2018 dollars

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =		\$616,847 per year in 2018 dollars
NOx Removed =		9 tons/year
Cost Effectiveness =		\$68,275.81 per ton of NOx removed in 2018 dollars



## Cost Estimate

Graymont Cricket Mountain Kiln 4

### Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ( $SNCR_{cost}$ ) =	\$1,935,617 in 2018 dollars
Air Pre-Heater Costs ( $APH_{cost}$ )* =	\$1,744,658 in 2018 dollars
Balance of Plant Costs ( $BOP_{cost}$ ) =	\$2,417,838 in 2018 dollars
<b>Total Capital Investment (TCI) =</b>	<b>\$7,927,545 in 2018 dollars</b>

\* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

### SNCR Capital Costs ( $SNCR_{cost}$ )

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ( $SNCR_{cost}$ ) =	\$1,935,617 in 2018 dollars
--	-----------------------------

### Air Pre-Heater Costs ( $APH_{cost}$ )\*

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs ( $APH_{cost}$ ) =	\$1,744,658 in 2018 dollars
---	-----------------------------

\* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

### Balance of Plant Costs ( $BOP_{cost}$ )

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs ( $BOP_{cost}$ ) =	\$2,417,838 in 2018 dollars
---	-----------------------------

## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$129,229 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$626,672 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$755,901 in 2018 dollars

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCI} =$	\$118,913 in 2018 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$8,695 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$442 in 2018 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$65 in 2018 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$1,022 in 2018 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$91 in 2018 dollars
Direct Annual Cost =		\$129,229 in 2018 dollars

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$3,567 in 2018 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCI} =$	\$623,105 in 2018 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$626,672 in 2018 dollars

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$755,901 per year in 2018 dollars
NOx Removed =	19 tons/year
Cost Effectiveness =	\$39,025.35 per ton of NOx removed in 2018 dollars

## Cost Estimate

Graymont Cricket Mountain Kiln 5

### Total Capital Investment (TCI)

For Coal-Fired Boilers:

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

For Fuel Oil and Natural Gas-Fired Boilers:

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

Capital costs for the SNCR ( $SNCR_{cost}$ ) =	\$1,858,982 in 2018 dollars
Air Pre-Heater Costs ( $APH_{cost}$ )* =	\$1,618,558 in 2018 dollars
Balance of Plant Costs ( $BOP_{cost}$ ) =	\$2,328,328 in 2018 dollars
<b>Total Capital Investment (TCI) =</b>	<b>\$7,547,629 in 2018 dollars</b>

\* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

### SNCR Capital Costs ( $SNCR_{cost}$ )

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

SNCR Capital Costs ( $SNCR_{cost}$ ) =	\$1,858,982 in 2018 dollars
--	-----------------------------

### Air Pre-Heater Costs ( $APH_{cost}$ )\*

For Coal-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

Air Pre-Heater Costs ( $APH_{cost}$ ) =	\$1,618,558 in 2018 dollars
---	-----------------------------

\* This factor applies because the boiler burns bituminous coal and emits equal to or greater than 0.3lb/MMBtu of sulfur dioxide.

### Balance of Plant Costs ( $BOP_{cost}$ )

For Coal-Fired Utility Boilers:

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

For Fuel Oil and Natural Gas-Fired Utility Boilers:

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

For Coal-Fired Industrial Boilers:

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

For Fuel Oil and Natural Gas-Fired Industrial Boilers:

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

Balance of Plant Costs ( $BOP_{cost}$ ) =	\$2,328,328 in 2018 dollars
---	-----------------------------

## Annual Costs

### Total Annual Cost (TAC)

$$\text{TAC} = \text{Direct Annual Costs} + \text{Indirect Annual Costs}$$

Direct Annual Costs (DAC) =	\$144,860 in 2018 dollars
Indirect Annual Costs (IDAC) =	\$596,640 in 2018 dollars
Total annual costs (TAC) = DAC + IDAC	\$741,500 in 2018 dollars

### Direct Annual Costs (DAC)

$$\text{DAC} = (\text{Annual Maintenance Cost}) + (\text{Annual Reagent Cost}) + (\text{Annual Electricity Cost}) + (\text{Annual Water Cost}) + (\text{Annual Fuel Cost}) + (\text{Annual Ash Cost})$$

Annual Maintenance Cost =	$0.015 \times \text{TCl} =$	\$113,214 in 2018 dollars
Annual Reagent Cost =	$q_{\text{sol}} \times \text{Cost}_{\text{reag}} \times t_{\text{op}} =$	\$26,674 in 2018 dollars
Annual Electricity Cost =	$P \times \text{Cost}_{\text{elect}} \times t_{\text{op}} =$	\$1,357 in 2018 dollars
Annual Water Cost =	$q_{\text{water}} \times \text{Cost}_{\text{water}} \times t_{\text{op}} =$	\$201 in 2018 dollars
Additional Fuel Cost =	$\Delta \text{Fuel} \times \text{Cost}_{\text{fuel}} \times t_{\text{op}} =$	\$3,135 in 2018 dollars
Additional Ash Cost =	$\Delta \text{Ash} \times \text{Cost}_{\text{ash}} \times t_{\text{op}} \times (1/2000) =$	\$279 in 2018 dollars
Direct Annual Cost =		\$144,860 in 2018 dollars

### Indirect Annual Cost (IDAC)

$$\text{IDAC} = \text{Administrative Charges} + \text{Capital Recovery Costs}$$

Administrative Charges (AC) =	$0.03 \times \text{Annual Maintenance Cost} =$	\$3,396 in 2018 dollars
Capital Recovery Costs (CR)=	$\text{CRF} \times \text{TCl} =$	\$593,244 in 2018 dollars
Indirect Annual Cost (IDAC) =	$\text{AC} + \text{CR} =$	\$596,640 in 2018 dollars

## Cost Effectiveness

$$\text{Cost Effectiveness} = \text{Total Annual Cost} / \text{NOx Removed/year}$$

Total Annual Cost (TAC) =	\$741,500 per year in 2018 dollars
NOx Removed =	61 tons/year
Cost Effectiveness =	\$12,199.11 per ton of NOx removed in 2018 dollars