Appendix O

Holcim-Clarksville BART Analysis

June 12, 2008

BART FIVE FACTOR ANALYSIS ▪ HOLCIM (US) INC

CLARKSVILLE, MISSOURI

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1. EXECUTIVE SUMMARY

This report documents the determination of the Best Available Retrofit Technology (BART) as proposed by Holcim (US) Inc. (Holcim) for the Portland cement manufacturing plant located in Clarksville, Missouri (Clarksville plant). This analysis is for the kiln system. Currently, particulate matter emissions from the kiln are controlled by an electrostatic precipitator. The Clarksville plant has other lesser emitting BART-eligible emissions units, all of which have Particulate Matter Control Devices (PMCDs) installed. The negligible visibility impairment attributable to these sources concludes that no additional controls are necessary to satisfy the requirements of the BART rule.[1]

Holcim used the U.S. Environmental Protection Agency's (EPA's) guidelines[2] in 40 CFR Part 51 to determine BART for the kiln. Specifically, Holcim conducted a five-step analysis to determine BART for SO_2, NOX, and PM_{10} 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 document the results;
5. Evaluating visibility impacts

Based on the five-step analysis, Holcim proposes the following as BART:

Kiln:

- PM_{10} – Holcim has determined that the existing electrostatic precipitator constitutes BART. This control device is effective for controlling PM_{10} from a wet kiln.

- NO_X – Holcim has determined that BART for the Holcim Clarksville Kiln is the installation and operation of a Mid Kiln Firing (MKF) system or equivalent technologies that will achieve a 20 percent reduction in the maximum daily NO_X emission rate of 73,185 lbs that was used for visibility impact modeling.

- SO_2 – Holcim proposes that BART for the Holcim Clarksville Kiln is fuel substitution or equivalent technologies that will achieve a 23 percent reduction in the maximum daily SO_2 emission rate of 117,345 lbs that was used for visibility impact modeling.

The proposed BART control strategies will result in reductions of the visibility impacts attributable to the Clarksville plant. A summary of the visibility improvement at Class I areas based on the existing emission rates and proposed BART emission rates is provided in Table 1-1.

[1] Holcim submitted an inventory of all of the BART-eligible emission sources to the MDNR. Based on a review of this information, the MDNR concluded that the contributions from particulate matter from the non-kiln sources to visibility impairment is negligible and further analysis of these smaller particulate matter sources was not required. Meeting with the MDNR dated January 23, 2008.

[2] 40 CFR 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations

TABLE 1-1. VISIBILITY IMPAIRMENT IMPROVEMENT

	Mingo National Wildlife Refuge	Hercules Glades Wilderness Area	Upper Buffalo Wilderness Area
Existing 98% Impact (Δdv)	1.01	0.81	0.61
BART 98% Impact (Δdv)	0.79	0.64	0.48
Improvement 98% Impact (Δdv)	22%	21%	22%

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
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.

BART applicability was determined for the Clarksville plant based on an applicability analysis performed by the MDNR and a refined applicability analysis performed by Holcim. Both analyses determined that the kiln is subject to BART. The details of the applicability determination can be found in Section 3.

Subsequently, Holcim performed an analysis to determine BART for each VAP for the kiln. The VAPs emitted by the kiln include NO_x, SO_2, and particulate matter with a mass mean diameter smaller than ten microns (PM_{10}) of various forms (filterable coarse particulate matter [PM_c], filterable fine particle 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 and NO_X can be found in Sections 4 and 5 respectively.

As stated in Section 2, a BART-eligible source is subject-to-BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandated Class I area." EPA has determined that a source is reasonably anticipated to contribute to visibility impairment if the 98th percentile of the visibility impacts from the source is greater than 0.5 Δdv when compared against a natural background. The MDNR conducted air quality modeling for the kiln to predict the existing visibility impairment attributable to the Clarksville plant in the following Class I areas:

- Mingo National Wildlife Refuge
- Hercules Glade Wilderness Area
- Upper Buffalo Wilderness Area

Based on this modeling, the MDNR concluded that the Clarksville plant was subject to BART since the 98th percentile of the visibility impacts attributable to the kiln are greater than 0.5 Δdv when compared against a natural background for a Class I area.

The modeling methods and procedures that Holcim followed were consistent with the methods and procedures that were followed in the MDNR's original modeling. Table 3-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}[3]. The SO_2 and NO_x emission rates are the highest actual 24-hour emission rates based on 2003-2007 continuous emissions monitoring system (CEMS) data. The PM_{10} emission rates are based on data included in Holcim's BART survey.

TABLE 3-1. MODELED 24-HOUR EMISSIONS (AS AN HOURLY EQUIVALENT)

SO_2 (lb/hr)	NO_X (lb/hr)	Total PM_{10} (lb/hr)
4889.38	3049.38	51.82

Table 3-2 summarizes the stack parameters that were used to model the kiln.

TABLE 3-2. SUMMARY OF STACK PARAMETERS

Parameter	Value
Actual Stack height (ft)	250
Stack Diameter (ft)	21.7
Exhaust Velocity (ft/s)	34.3
Exhaust Temperature (F)	367

The results of the modeling indicate that the 98th percentile of the visibility impacts are greater than 0.5 Δdv when compared against a natural background. Since the visibility impacts are greater than 0.5 Δdv, the kiln is subject to BART. The results of the modeling are summarized in Table 3-3.

[3] The non-kiln PM_{10} emissions were included in the model as part of the kiln PM_{10} emissions.

TABLE 3-3. SUMMARY OF 98TH PERCENTILE VISIBILITY IMPACTS AND NUMBER OF DAYS WITH VISIBILITY IMPACT GREATER THAN 0.5 ΔDV

Class I Area	Visibility Impairment	
	98th % Δdv	Days > 0.5 Δdv
Mingo Wilderness	1.01	75
Hercules Glades Wilderness	0.81	40
Upper Buffalo Wilderness	0.61	33

Table 3-4 provides a breakdown of the visibility impacts listed in Table 3-3 by each VAP for the high (98th percentile) day (note that the specific percentiles vary from day to day, and location to location, the breakdown listed is an example of one event only).

TABLE 3-4. BREAKDOWN OF POLLUTANT SPECIFIC CONTRIBUTIONS TO VISIBILITY FOR THE 98TH PERCENTILE DAY.

Class I Area	Visibility Impairment Attributable to SO_4 (%)	Visibility Impairment Attributable to NO_3 (%)	Visibility Impairment Attributable to SOA (%)	Visibility Impairment Attributable to EC (%)	Visibility Impairment Attributable to PM_c (%)	Visibility Impairment Attributable to PM_f (%)	Total Visibility Impairment (Δdv)
Mingo Wilderness	98.6	1.2	0	0	0	0.2	1.01
Hercules Glades Wilderness	42.3	57.5	0	0	0	0.2	0.81
Upper Buffalo Wilderness	95.7	4.2	0	0	0	0.1	0.61

As shown in Table 3-4, the most significant contributors to the visibility impairment are sulfates (SO_4) and nitrates (NO_3). The SO_4 contribution is from the chemical conversion of SO_2 emitted by the kiln to SO_4. The NO_3 contribution is entirely from the chemical conversion of NO_X emitted from the kiln. The contribution of PM_{10} to the total visibility impairment can be estimated as the sum of the contributions from SOA, EC, PMc, and PMf. The PM_{10} contribution is much smaller (<1%) than the contribution from SO_2 and NO_X.

Sulfur, in the form of metallic sulfides (pyrite), sulfate, or organosulfur compounds, is often found in the raw materials used to manufacture cement and in the solid and liquid fuels burned in cement kilns.[4] The raw materials and fuels for the Clarksville plant are no exception. Sulfur dioxide can be generated by the oxidation of sulfur compounds in the raw materials and fuels during operation of the pyroprocess. Constituents found in fuels, raw materials, and in-process materials, such as the alkali metals (sodium and potassium), calcium carbonate, and calcium oxide react with SO_2 formed in the pyroprocess and much of the sulfur leaves the process in the principle product of the kiln system called clinker.

The kiln is the only BART source which emits SO_2, thus an SO_2 BART evaluation was performed only for the kiln. The maximum actual 24-hour kiln SO_2 emission rate that was modeled for the BART applicability determination is summarized in Table 4-1.

TABLE 4-1. EXISTING ACTUAL MAXIMUM 24-HOUR SO_2 EMISSION RATES

	SO_2 24-Hour Emission Rate ton/24-hr	SO_2 Hourly Equivalent Emission Rate lb/hr
Kiln	58.67	4889.38

4.1 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. A list of control technologies was obtained by reviewing the U.S. EPA's Clean Air Technology Center, publicly-available air permits, applications, and technical literature published by the U.S. EPA, state agencies, and Regional Planning Organizations (RPOs).

The available retrofit SO_2 control technologies are summarized in Table 4-2.

TABLE 4-2. AVAILABLE SO_2 CONTROL TECHNOLOGIES

SO_2 Control Technologies
Fuel Substitution
Raw Material Substitution
Dry Lime Injection/Scrubbing
Wet Lime Scrubbing

[4] Miller, F. MacGregor and Hawkins, Garth J., "Formation and Emission of Sulfur Dioxide from the Portland Cement Industry", *Proceedings of the Air and Waste Management Association*, June 18-22, 2000.

4.2 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.

4.2.1 FUEL SUBSTITUTION

Holcim uses a mixture of coal, petroleum coke, alternative fuels (synfuel), and oil as the primary fuels for the kiln. For example, the 2007 actual fuel usage breakdown on an energy input basis, was 3.4 percent coal, 84 percent petroleum coke, 11.8 percent synfuel, and 0.8 percent oil (the fuel usages are also on an as received basis). The sulfur content of the petroleum coke is approximately 5.72 percent and the sulfur content of the coal is approximately 3.45 percent. Oil is typically used during preheat of the kiln after a maintenance outage. Coal is also typically used during the kiln startup after an extended shutdown. Coal offers better flame control and appropriate heat distribution during heatup and ramp up of production. The main source of solid fuel for the kiln is petroleum coke.

The design of the long wet kiln system is such that some of the SO_2 resulting from fuel combustion may be emitted and the rest is absorbed in clinker or CKD. Therefore, if Holcim reduces sulfur in the fuel input to the kiln, a corresponding reduction in SO_2 emissions from the kiln would be expected. Holcim contacted fuel suppliers and found a low sulfur PRB coal, 0.7 % sulfur, and a regionally available 3.0% sulfur coal that could be used in lieu of the current coal/coke, which would result in a lower overall fuel sulfur content. A number of coal sources were rejected for high chlorine content. For example, a 1.0 percent sulfur source was found but the chlorine content was 1.3 percent (the mine has recently shut down as well), another mine had coal with sulfur in the 1.0 percent and 2.5 percent range, but with chlorine contents in the 0.3 percent range. Further, a 2.8 percent sulfur coal was identified, but it also had too high of a chlorine content, 0.12 percent, to be usable. The 3.0 percent sulfur coal is reported as having a chlorine content of 0.05 percent which is preferable (Note that the 2007 average chlorine content in the coke was 0.08 percent. A summary of the coal composition data obtained is provided in Appendix A. In addition, the plant is subject to chlorine input limitations from HWCMACT). Chlorine contents higher than current levels would very likely cause visible plumes/opacity issues as further described in Appendix B.

Determining the specific reduction in SO_2 emissions from a reduction in fuel sulfur is complicated as the reactions in the kiln system are complex. The sulfur is introduced into the system in the fuel as well as the raw materials (pyrites) and the sulfur exits the kiln system in the product (clinker), the cement kiln dust (CKD), and out the stack as SO_2. Further, although the sulfur in the clinker is small on a percentage basis, the magnitude of the clinker production is extremely large (greater than 1 million tons per year). Consequently, small changes in the amount of sulfur absorbed in the product can dramatically change the amount of SO_2 emitted. The variation in sulfur in the raw materials from the quarry, the clinker quality requirement determined by the market, and the kiln conditions can all cause significant changes in kiln operating parameters, such as kiln burning temperature, kiln excess Oxygen, etc. These changes can have a strong impact on the sulfur absorbed in the clinker and CKD and hence on SO_2 emissions. These operating conditions can also strongly change how the fuel sulfur affects SO_2 emissions. Reviewing the data yields that there is no linear correlation between fuel sulfur and SO_2

emissions. Although these parameters were continuously monitored and controlled, to calculate an SO_2 control effectiveness, based on switching to a lower sulfur fuel, a high number of assumptions must be made with a very low confidence in the accuracy. Regardless, an attempt has been made.

The assumptions, based on long term averages in 2007, which can vary significantly on an annual and short term (24-hr) basis, include that 65 percent of sulfur input in the kiln system is from fuel, 35 percent of sulfur input is from raw materials, and approximately 30-35 percent of total sulfur input is estimated to ultimately be emitted as SO_2 in the stack.

Low Sulfur PRB Coal – 0.7 percent sulfur

Based on the 2007 data, if all of the current coal and coke is replaced with a 0.7 percent low sulfur coal, the sulfur input from fuel is calculated to be reduced by approximately 85 percent. Following is a summary of the sulfur input reduction from the use of low sulfur coal. The low sulfur PRB coal has a lower heat content (26 Gj/Metric ton) and higher moisture content than the coke currently being used (33 Gj/Metric ton), so a higher volume of low sulfur PRB coal is needed than coke reduced.

Current – 2007 Average

Coke Usage:	160,915 metric tons
Low Heat Content	32.510 Gj/Mt
Sulfur Content:	5.72 %
Sulfur Input from Coke:	9,204 metric tons
Current Coal Usage:	9,432 metric tons
Low Heat Content	22.177 Gj/Mt
Sulfur Content:	3.45 %
Sulfur Input from Coal:	325 metric tons
Total Sulfur Input from Coke/Coal:	9,529 metric tons

Low Sulfur PRB Coal Replacement

Coal Usage:	208,546 metric tons
Heat Content	26.266 Gj/Mt
Sulfur Content:	0.7 %
Total Sulfur Input from Coal:	1,459 metric tons

Net reduction in sulfur input from coal:

9,529 metric tons – 1,459 metric tons = 8,070 metric tons = 8,893 tons

The SO_2 reduction calculation, based on the calculated sulfur reduction, is very complicated. The pyrite sulfur from the raw materials can volatilize at relatively low temperatures in the kiln, in an area where the sulfur comes in contact with the kiln feed that has only minimally been calcined into CaO. Consequently, less of this sulfur reacts with the CaO and thus is emitted. Again, if the sulfur reacted with the CaO, it would be absorbed into the clinker and CKD. The fuel sulfur, on the other hand, enters the kiln in

the burning zone and travels the entire length of the kiln, coming in contact with much higher concentrations of CaO, thus having a much greater chance of being absorbed. Consequently, there is no simple linear relationship between fuel sulfur and SO_2 emissions that can be used to confidently calculate an SO_2 reduction.

The fuel sulfur reduction of 8,893 tons corresponds with a 54 percent reduction of the total sulfur (fuel and raw material sulfur) input to the kiln system in 2007. As mentioned above, a large fraction of fuel sulfur would have been absorbed by the CaO in the system, and thus would not have been emitted as SO_2, while SO_2 emitted from the pyrite in the raw materials has less of a chance of being absorbed, so there is not a directly proportional reduction in SO_2 with the sulfur reduction from the fuels, nor with the total sulfur reduction. Holcim estimates that based on the year 2007 data, the actual SO_2 reduction is about 40% - 50%.

Regional Coal – 3.0 percent.
Using calculation methods similar to the low sulfur PRB coal case, a scenario that included replacing the current coal/coke with a 3.0 percent coal was evaluated. This scenario results in a sulfur input reduction of approximately 28 percent. Holcim estimates that the actual SO_2 reduction from this fuel switch would be approximately 20 - 25 percent.

These reductions are the maximum reductions in tons of SO_2 that can be expected. As mentioned previously, the actual reduction will vary significantly, especially on a short term basis. Holcim estimates that the net reduction in SO_2 for 3.0 percent sulfur coal would be 20-25 percent and for low sulfur PRB coal would be in the range of 40 percent to 50 percent.

Holcim considers this technology to be technically feasible and will consider it further.

4.2.2 RAW MATERIAL SUBSTITUTION / SELECTIVE MINING

In a long wet kiln, not only the pyritic sulfur, but total sulfur in the raw materials will have an impact on SO_2 emissions.

Part of the pyritic sulfur reacts with oxygen and forms SO_2 at the relatively lower temperature zone of the kiln. The rest of the sulfur, such as sulfates and sulfur compounds, enters the kiln at higher temperature zones, where more SO_2 is volatized. Some of this SO_2 will pass the length of the kiln without being absorbed and will thus be emitted to the stack.

Using raw materials with lower sulfur content can reduce the potential for SO_2 emissions from a wet kiln system. The limestone, shale, and other raw materials used at the Clarksville plant contain pyrites and total sulfur in varying concentrations. If zones or layers in the on-site quarry could be identified and mined selectively such that lower sulfur content materials are used, the emission rate of SO_2 could theoretically be reduced.

The Clarksville Quarry Scheduling Optimization (QSO) Model was created specifically for predicting relevant mineralogical parameters related to clinker production. Major oxides (Ca, Mg, Si, and Fe) are the primary focus of this predictive model. The sampling protocol and data analysis required for major oxide components was never intended to be adequate

for the accurate prediction of minor components, such as sulfur and sulfur compounds (See Appendix C for additional discussions on selective mining limitations based on Holcim's QSO (Quarry Scheduling Optimization) computer model).

Based on the lack of available data to predict if selective mining would be feasible, Holcim has concluded that selective mining is not considered a technically feasible SO_2 control technology for the kiln.

4.2.3 DRY LIME INJECTION/DRY LIME SCRUBBING

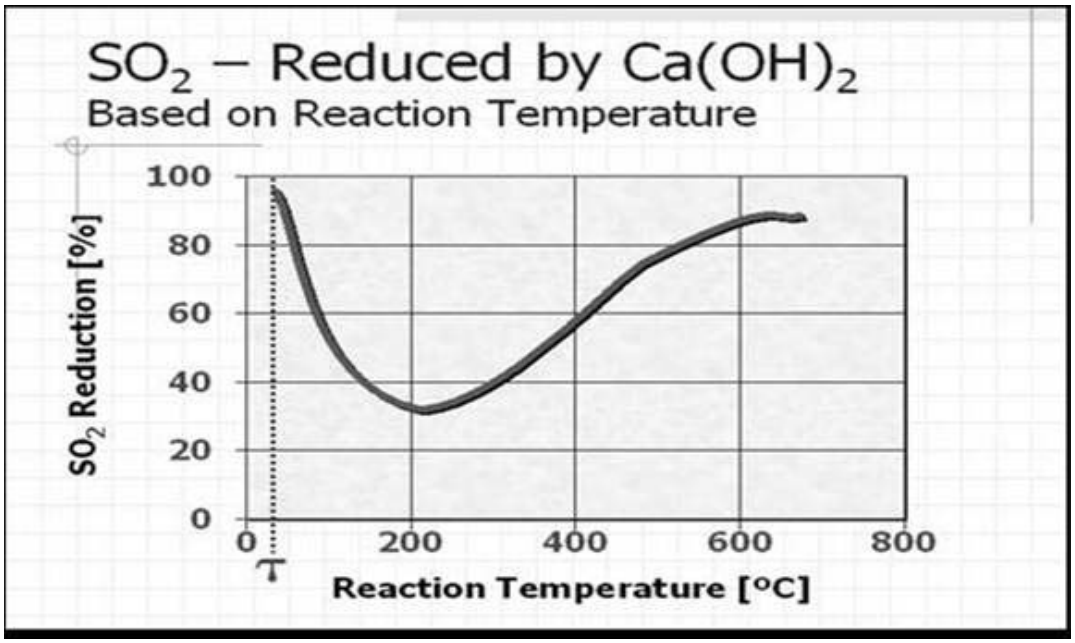
Dry Lime Injection, or Dry Lime Scrubbing (DLS), consists of injecting hydrated lime, $Ca(OH)_2$, into the flue gas. The $Ca(OH)_2$ reacts with SO_2 in the flue gas stream to create fine particles of $CaSO_3$ or $CaSO_4$. The particles are collected in the particulate matter control device (PMCD) serving the kiln.

The current PMCD was not sized/designed to handle the additional particulate matter loading that would result from this technology. Consequently, adding DLS could cause PM emissions and opacity to increase above permitted levels requiring Holcim to replace the existing PMCD (an ESP) with a new PMCD (a Baghouse).

Holcim is aware of only one other long term application of this technology on a wet kiln, which is on a smaller wet kiln in Belgium. Consequently, very little data exists to directly quantify the feasibility or benefit (emission reduction) of such a system. Regardless, Holcim is considering the technology to be technically feasible.

The effectiveness of DLS is impacted by both the temperature and the residence time/air flow rate at the location it is injected. At Clarksville, the injection point would be between the kiln outlet and the PMCD. At this location, the temperature is approximately 200 deg C (415 deg F). The temperature can not be increased at this location as the plant has limitations on the inlet temperature to the PMCD from both the Portland Cement MACT and the Hazardous Waste Combustion MACT in order to meet the Dioxin/Furan (D/F) limit. Further, lowering the temperature would lead to lower ESP efficiency and opacity problems. Figure 4-1 is a plot of SO_2 reduction versus reaction temperature from a commonly used article entitled "What is Achievable with Today's Technologies", Mark S. Terry, Krupp Polysius Corp, 2001. As indicated in the figure, at a temperature of 200 deg C (415 deg F), the reduction level is approximately 30 percent, which is the lowest reduction level over the temperature range presented.

FIGURE 4-1. SO_2 REDUCTION VERSUS REACTION TEMPERATURE FOR HYDRATED LIME



The molar ratio of lime (calcium source) to SO_2 is much higher than in a typical coal fired boiler due to a number of factors, some of which include the higher CO_2 and dust levels in the cement kiln system exhaust. The CO_2 competes with SO_2,in the reaction with the lime, and the higher dust loading reduces the even distribution of the lime in the gas. Based on a communication with the Obourg plant in Belgium, a molar ratio of between 4:1 and 6:1 has been used. The larger size of the Clarksville kiln will make it more difficult to evenly distribute the lime to the kiln gas and thus Holcim anticipates that a molar ratio of 6:1 will be required to achieve a maximum control efficiency of 20 - 30 percent.

Holcim considers this technology to be technically feasible and will consider it further.

4.2.4 WET LIME SCRUBBING

Wet lime scrubbing (WLS) is a name for a traditional tailpipe wet scrubber. This process involves passing the flue gas from the main PMCD through a sprayed aqueous suspension of $Ca(OH)_2$ or $CaCO_3$ (limestone) that is contained in an appropriate scrubbing device. In the case of the Clarksville plant, the basic underlying economics would dictate the use of ground limestone as the scrubbing reagent. Use of the cement kiln dust as a scrubbing reagent was not considered as a viable option for Clarksville due to its high chlorine content and a large amount of inerts. In WLS, the aqueous suspension of scrubbing reagent is not taken to dryness as it is in DLS. The SO_2 reacts with the scrubbing reagent to form $CaSO_3.H_20$ or gypsum that is collected and retained as aqueous sludge. The sludge is either dewatered and disposed of or used as synthetic gypsum.

The scrubbing efficiency of WLS can vary from an estimated 80 percent to 95 percent of the SO_2 in the flue gas treated by the scrubber[5]. Further, WLS is a high maintenance process with high rates of downtime expected from build up or plug up of mist-eliminators or spray nozzles and the severe wear and corrosion of components. Holcim has found that high levels of hydrocarbons (THC) in the gas stream have caused significant corrosivity and foam build-up at their Dundee plant. Further, it significantly influences the system availability and the efficiency. The THC levels at the Clarksville plant may also lead to build up and plugging, and thus an availability (uptime) of the WLS of 95 percent is assumed.

Despite these identified drawbacks, WLS is considered a technically feasible BART option.

4.3 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. Table 4-3 provides the effectiveness of each technology in the form of an annual average efficiency.

Table 4-3. Ranking of Technically Feasible Kiln SO_2 Control Technologies by Effectiveness

Control Technology	Effectiveness SO_2 Reduction (Percent Reduction – Annual Basis)
Wet Lime Scrubbing	80-95%
Fuel Substitution	20-50%
Dry Lime Scrubbing	20-30%

4.4 Evaluation of Impacts for Feasible SO_2 Controls

Step four of the BART analysis procedure is the impact analysis. The BART determination guidelines list the 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

Holcim has conducted an impact analysis for the remaining SO_2 control options.

[5] Assessment of Control Technology Options for BART-Eligible Sources Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities. Prepared by Northeast States for Coordinated Air Use Management In Partnership with The Mid-Atlantic/Northeast Visibility Union, March 2005, Page 4-21, Table IV-4. Range of Removal Efficiencies of Wet SO2 Scrubbers for Long Wet Kilns.

4.4.1 WET LIME SCRUBBING

Cost of Compliance

Holcim utilized a recent WLS vendor bid, scaled to 2012 dollars[6], as the basis for the economic analysis to determine the annualized cost for WLS. Holcim divided the annualized cost of WLS by the annual tons of SO_2 reduced to determine the cost effectiveness for WLS. The "annual tons reduced" were determined by subtracting the estimated controlled annual emissions from the existing annual emissions. The existing annual emissions should be considered both on a projected actual and a potential to emit (PTE) basis. The projected actual (PA) annual SO_2 emissions provided to the MDNR in the recent Mid Kiln Firing (MKF) permit application was 11,481 tons/year[7]. The PTE listed in the MKF permit is 13,298 tons/year. The estimated controlled annual emissions were calculated by applying an 80 percent to 95 percent control efficiency and a 95 percent control device uptime, to the projected actual annual and PTE emissions. Table 4-4 provides a summary of the cost effectiveness analysis related to WLS. The detailed cost analysis table is provided in Appendix D.

The equipment cost includes both the WLS system and a limestone preparation system. The limestone preparation system includes 2 Ball Mills used to grind the limestone received to a specific fineness.

The cost effectiveness analysis does not include the cost to construct a new exhaust stack, which may be needed to employ the WLS technology, and it does not include the possible additional cost for the equipment relocation on site due to the limited space available for the WLS system.

The control cost factors were obtained from the EPA's Control Cost Manual, 6th Edition.

Two factors that significantly increase the cost of this technology are the need to reheat the exhaust gas and the cost of sludge disposal.

<u>Exhaust Gas Reheat</u>

A common concern of utilizing a wet scrubber on a cement kiln exhaust gas is the probable formation of a detached plume resulting in opacity violations. For a typical cement kiln stack, if the exhaust gas contains NH_3, HCl, and SO_2, sub-micron aerosols of NH_4Cl and $(NH_4)2SO_4$ may form when the gas temperature is reduced after exiting the stack. A detached plume is predicted to occur when the exhaust gas is cooled to the dew point at or near the exit of the stack and prior to the dilution of the aerosol forming constituents. The wet scrubber requires the exhaust gas to be cooled to the dew point at the inlet of the scrubber. As the temperature of the exhaust gas is cooled in the scrubber, a visible plume

[6] The most recent U.S. Department of Labor, Producer Price Index Industry Data, from April 2004 – April 2008 indicates that costs have increased by the ratio of 143.2/102.9 over the last 5 year period (or 8.06 points per year). The original bid was from 2005. Consequently, the equipment cost was scaled up to 2012 (8 years) by multiplying by the following percentage (100 + (8 x 8.06)) percent = 1.645.

[7] The projected actual annual emission rate was determined as part of the construction permit application process to support the August 27, 2007 Mid Kiln Firing construction permit. Permit Number 082007-019.

condition is nearly assured. The sub-micron NH_4Cl aerosol will be formed and is difficult to remove in the scrubber. This problem has been reported for wet scrubbers used at cement plants. As the plant is subject to a 20 percent opacity limitation from both the PCMACT and HWCMACT, even a small increase in opacity could lead to an exceedance of the standard, which is not acceptable. Based on information from Holcim's Dundee, Michigan plant, Holcim anticipates that the temperature of the exhaust gas at the exit of the scrubber would be approximately 170 deg F. To keep the sub-micron particles from forming at the exit of the stack, reheating the exhaust gas, after the scrubber, is required. A thorough evaluation of the stack gas constituents was conducted by Holcim and it was determined that to prevent an unacceptable increase in opacity from occurring, the stack gas would need to be reheated (if a scrubber is installed) to at least the current gas temperature after the ESP of approximately 380 deg F (see Appendix B for the detailed analysis). This re-heating would most likely be achieved using natural gas combustion. The natural gas combustion would lead to a 97 ton/year increase in NO_x emissions that would negatively impact visibility gains from the SO_2 reduction.

Sludge Disposal

The sludge generated from the WLS system may require disposal. Therefore, Holcim has determined the cost of disposal based on a bid from Area Disposal Services, Inc. for the disposal fee ($36/ton), as well as the cost for trailer rental ($120/month) and transportation ($220/load). In addition, Holcim also looked at the corresponding cost of building an onsite landfill for disposal, but based on information provided by MDNR, the time and resources required to obtain a permit, and the additional liability associated with an onsite landfill, Holcim decided not to pursue that option.

WLS may also lead to an increase in PM emissions because some particles of limestone or $CaSO_3$ will be entrained in the flue gas and subsequently be emitted from the scrubber. WLS is also known to increase emissions of sulfuric acid mist.[8]

TABLE 4-4. COST ANALYSIS SUMMARY FOR WET LIME SCRUBBING

Control Case	Control Effectiveness (%)	Annual Cost ($/yr)	Existing Annual Emissions (tons/yr)	Pollutant* Removed (tons/yr)	Cost** Effectiveness ($/ton)	Cost*** Impact ($/ton clinker)
WLS – PA	80%	$24,385,436	11,481	8,726	$2,826	$20
WLS – PA	95%	$24,925,003	11,481	10,362	$2,428	$21
WLS – PTE	80%	$24,840,863	13,298	10,106	$2,482	$20
WLS – PTE	95%	$25,465,823	13,298	12,001	$2,139	$21

*Assumes 95% uptime.

**Includes 97 tons of NOx generated.

***Based on a maximum historical actual clinker production rate of 1,215,708 tons/year.

[8] *Innovations in Portland Cement* Manufacturing, Portland Cement Association, 2004, pg. 660 & 669

The significant increases in cost per ton of clinker produced from using WLS, as shown in Table 4-4, would likely eliminate any profit margin currently realized by the plant. Thus, it would not be economically feasible to operate the plant with WLS.

Energy Impacts
A wet scrubber requires an additional fan of considerable horsepower to move the flue gas through the scrubber. The exhaust gas reheat requirement will utilize approximately 1,000,000 MMcf/year of natural gas, which will itself lead to an increase in NOx emissions of 97 tons/yr.

Non Air-Quality Impacts
Without reheating, a frequent steam plume and/or detached plume can be expected at the discharge of the wet scrubber that would result in visual impairment in the area.

The WLS technology could generate over 50,000 tons per year of waste (sludge) that will require disposal in a landfill.

Remaining Useful Life
The remaining useful life of the kiln does not impact the annualized cost of WLS because the useful life is anticipated to be at least as long as the capital cost recovery period, which is 15 years.

4.4.2 FUEL SUBSTITUTION

Cost of Compliance

Low sulfur PRB coal
The increased cost of using low sulfur PRB coal (0.7 percent sulfur) includes the relative increase in fuel cost as well as the cost of a new coal mill system. Low sulfur PRB coal is harder than the current coal/coke utilized and has a lower heat content; consequently, a higher volume of coal grinding will be needed than the current mill can achieve. The increased grinding requirement would also have an additional energy requirement. A bid for a new coal mill, classifier, and mill motors, was obtained from GEBR. Pfeiffer USA Inc. and was scaled to 2012 dollars[9],

Regional 3.0 percent sulfur coal
The increased cost of using a regional 3.0 percent sulfur coal includes the relative increase in fuel cost as well as the cost of a new primary air fan and associated equipment. The 3.0 percent sulfur coal has a lower heat content than coke; consequently, a higher volume of coal will be needed that will require a larger primary air fan. Holcim is proposing to

[9] The most recent U.S. Department of Labor, Producer Price Index Industry Data, from April 2004 – April 2008 indicates that costs have increased by the ratio of 143.2/102.9 over the last 5 year period (or 8.06 points per year). The original bid was from 2007. Consequently, the equipment cost was scaled up to 2012 (5 years) by multiplying by the ratio of 143.2/102.9.

change the coal mill primary air fan and associated equipment. Reducing the capital cost does not have a significant impact on the outcome of the cost analysis. That is, eliminating the capitol cost completely only reduces the cost from $1,286/ton SO2 to $1,039/ton SO_2. Consequently, Holcim has chosen to not spend additional time and effort documenting these costs.

Table 4-5 provides a summary of the cost effectiveness analysis related to Fuel Substitution. The detailed cost analysis table is provided in Appendix D.

The cost effectiveness analysis does not include the cost to construct any new storage or handling facilities for the low sulfur PRB coal that may be required.

The control cost factors were obtained from the EPA's Control Cost Manual, 6th Edition.

TABLE 4-5. COST ANALYSIS SUMMARY FOR FUEL SUBSTITUTION

Control Case	Control Effectiveness (%)	Annual Cost ($/yr)	Existing Annual Emissions (tons/yr)	Pollutant Removed (tons/yr)	Cost Effectiveness ($/ton)	Cost* Impact ($/ton clinker)
Fuel Sub – PA	23%	$3,933,016	11,481	2,641	$1,489	$3
Fuel Sub – PA	40%	$27,218,156	11,481	4,592	$5,927	$22
Fuel Sub – PA	50%	$27,218,156	11,481	5,741	$4,741	$22
Fuel Sub – PTE	23%	$3,933,016	13,298	3,059	$1,286	$3
Fuel Sub – PTE	40%	$27,218,156	13,298	5,319	$5,117	$22
Fuel Sub – PTE	50%	$27,218,156	13,298	6,649	$4,094	$22

*Based on a maximum historical actual clinker production rate of 1,215,708 tons/year

The 3.0 percent sulfur coal option (used 23 percent control as the average) is cost effective and will be considered further.

The low sulfur PRB coal option (40 to 50 percent control) is not cost effective and results in significant increases in cost per ton of clinker produced that would likely eliminate any profit margin currently realized by the plant. Thus, it would not be economically feasible to operate the plant with the low sulfur PRB coal scenario.

In addition, for this analysis Holcim did consider the blending of solid fuel but considered it also to not be cost effective. In order to properly blend solid fuels for a precise distribution to control sulfur and chlorine inputs and not disrupt production due to fuel quality swings, an additional solid fuel equipment handling system would have to be installed. At a minimum, for each additional solid fuel used a system consisting of feed chutes, transfer conveyors, a storage silo, and a weigh belt would be required. It was conservatively estimated that the cost would be similar to the cost of a new mill and thus increase the cost well above the 3.0% sulfur coal option.

Energy Impacts
The low sulfur PRB coal will require additional energy for grinding. The actual increase is difficult to estimate. The regional coal option also relies that a reliable source of tire derived fuel (TDF) and Hazardous Waste Derived Fuel (HWDF) is available to supplement 23% of the thermal requirements for clinker production

Non Air-Quality Impacts
None.

Remaining Useful Life
The remaining useful life of the kiln does not impact the annualized cost because the useful life is anticipated to be at least as long as the capital cost recovery period, which is 15 years.

4.4.3 DRY LIME SCRUBBING

Cost of Compliance
The increased cost of DLS includes the cost of hydrated lime as well as the injection system and replacing the existing ESP with a new baghouse. As the DLS injection system would likely be a custom application, Holcim's engineering department has estimated that the DLS injection system equipment cost would be approximately $1,000,000. Holcim obtained a bid for retrofitting the existing ESP with a Baghouse from GE Energy. A detailed analysis has not yet been completed to determine if the retrofit will be capable of handling the additional dust loading from the DLS system.

The quantity of hydrated lime required is calculated below on a PA and PTE basis as follows:

<u>Hydrated Lime Requirement.</u>

PA Basis:

The projected actual annual emission level of SO_2 is 11,481 tons

A molar ratio of 6:1, $Ca(OH)_2$ to SO_2, is required. The $Ca(OH)_2$ required is calculated by multiplying by the ratio of molecular weights:

6 x 11,481 tons SO_2 x (74 ton $Ca(OH)_2$/ 64 SO_2) = 79,649 tons $Ca(OH)_2$

The estimated purity of the hydrated lime is 96.8 percent $Ca(OH)_2$. Consequently, the amount required is scaled as follows:

79,649 tons $Ca(OH)_2$ / 0.968 = 82,282 tons hydrated lime

PTE Basis:

The PTE annual emission level of SO_2 is 13,298 tons

A molar ratio of 6:1, $Ca(OH)_2$ to SO_2, is required. The $Ca(OH)_2$ required is calculated by multiplying by the ratio of molecular weights:

6 x 13,298 tons SO_2 x (74 ton $Ca(OH)_2$/ 64 SO_2) = 92,255 tons $Ca(OH)_2$

The estimated purity of the hydrated lime is 96.8 percent $Ca(OH)_2$. Consequently, the amount required is scaled as follows:

92,255 tons $Ca(OH)_2$ / 0.968 = 95,304 tons hydrated lime

Table 4-6 provides a summary of the cost effectiveness analysis related to DLS. The detailed cost analysis table is provided in Appendix D. The control cost factors were obtained from the EPA's Control Cost Manual, 6th Edition.

TABLE 4-6. COST ANALYSIS SUMMARY FOR DRY LIME SCRUBBING

Control Case	Control Effectiveness (%)	Annual Cost ($/yr)	Existing Annual Emissions (tons/yr)	Pollutant Removed (tons/yr)	Cost Effectiveness ($/ton)	Cost* Impact ($/ton clinker)
DLS – PA	20%	$14,725,124	11,481	2,181	$6,750	$12
DLS – PA	30%	$14,725,124	11,481	3,272	$4,500	$12
DLS – PTE	20%	$16,756,579	13,298	2,527	$6,632	$14
DLS – PTE	30%	$16,756,579	13,298	3,790	$4,421	$14

*Based on a maximum historical actual clinker production rate of 1,215,708 tons/year

The significant increases in cost per ton of clinker produced from using DLS, as shown in Table 4-6, would likely eliminate any profit margin currently realized by the plant. Thus, it would not be economically feasible to operate the plant with DLS.

Energy Impacts
Additional electricity is needed for the pump used to inject the lime into the kiln gas.

Non Air-Quality Impacts
Utilizing DLS could also increase the amount of CKD sent to the landfill.

Remaining Useful Life
The remaining useful life of the kiln does not impact the annualized cost because the useful life is anticipated to be at least as long as the capital cost recovery period, which is 15 years.

4.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS

A final impact analysis was conducted to assess the visibility improvement for the existing emission rate when compared to the emission rate of WLS, Fuel Substitution, and DLS. The existing emission rates, and emission rates associated with controls, were modeled using CALPUFF. The existing emission rate is the same rate that was modeled for the BART applicability analysis. The SO_2

emission rate associated with WLS, Fuel Substitution, and DLS is the existing emission rates less the average anticipated control of 87.5 percent, 45 percent and 23 percent, and 25 percent respectively. The emission rates are summarized in Table 4-7.

TABLE 4-7. SUMMARY OF EMISSION RATES MODELED IN SO_2 CONTROL VISIBILITY IMPACT ANALYSIS

Emission Rate Scenario	Emission Rate		
	SO_2 (lb/hr)	NO_X (lb/hr)	PM_{10} (lb/hr)
WLS – 87.5%	611	3,049	51.82
Fuel Substitution – 45%	2,689	3,049	51.82
Fuel Substitution – 23%	3,765	3,049	51.82
DLS – 25%	3,667	3,049	51.82
Base case – Max 24-hr avg.	4,889	3,049	51.82

Comparisons of the existing visibility impacts and the visibility impacts based on WLS, Fuel Substitution, and DLS are provided in Table 4-8. The visibility improvement associated with the controls are also shown in Table 4-8; this value was calculated as the difference between the existing visibility impairment and the visibility impairment for the controlled emission rates as measured by the 98th percentile modeled visibility impact.

TABLE 4-8. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS

	Mingo National Wildlife Refuge	Hercules Glades Wilderness Area	Upper Buffalo Wilderness Area
Existing 98% Impact (Δdv)	1.01	0.81	0.61
WLS 98% Impact (Δdv)	0.48	0.31	0.21
WLS Improvement 98% Impact (Δdv)	0.53	0.50	0.40
(45% Control) Fuel Subs. 98% Impact (Δdv)	0.70	0.58	0.37
Fuel Subs Improvement 98% Impact (Δdv)	0.31	0.23	0.24
(23% Control) Fuel Subs. 98% Impact (Δdv)	0.87	0.72	0.48
Fuel Subs Improvement 98% Impact (Δdv)	0.14	0.09	0.13
DLS 98% Impact (Δdv)	0.87	0.70	0.48
DLS Improvement 98% Impact (Δdv)	0.14	0.11	0.13

4.6 PROPOSED BART FOR SO_2

Holcim reviewed each control option's availability, as well as its cost of compliance, energy impacts, and non-air quality impacts, as well as the remaining useful life of the kiln. Table 4-9 summarizes the cost effectiveness for the controls based on the tons of SO_2 reduced and the visibility improvement in deciviews.

TABLE 4-9. SUMMARY OF COST EFFECTIVENESS OF SO_2 CONTROL OPTIONS

Control Option*	Existing Emissions (tons/yr)	Reduced Annual Emissions (tons/yr)	Annual Cost ($/yr)	Cost** Effectiveness ($/ton)	Cost Impact ($/ton clinker)
WLS–PA–80%	11,481	8,726	$24,385,436	$2,826	$20
Fuel Sub–PA-40%	11,481	4,592	$27,218,156	$5,927	$22
Fuel Sub–PA–23%	11,481	2,641	$3,933,016	$1,489	$3
DLS – PA - 20%	11,481	2,181	$14,725,124	$6,750	$12

*The worst case scenario from a cost effectiveness perspective is provided.

**Includes 97 tons of NOx generated for WLS

Control Type **WLS–PA–80%** Class I Area	Base 98th Percentile Impact (DV)	Controlled 98th Percentile Impact (DV)	98th Percentile Improvement (DV)	98th Percentile Improvement (%)	Cost Effectiveness ($/DV)
Mingo	1.01	0.48	0.53	52.5	$46,010,256
Hercules	0.81	0.31	0.50	61.7	$48,770,872
Buffalo	0.61	0.21	0.40	65.6	$60,963,590
Control Type **Fuel Subs. – 40%** Class I Area	Base 98th Percentile Impact (DV)	Controlled 98th Percentile Impact (DV)	98th Percentile Improvement (DV)	98th Percentile Improvement (%)	Cost Effectiveness ($/DV)
Mingo	1.01	0.70	0.31	30.7	$87,800,502
Hercules	0.81	0.58	0.23	28.4	$118,339,807
Buffalo	0.61	0.37	0.24	39.3	$113,408,982
Control Type **Fuel Subs. - 23%** Class I Area	Base 98th Percentile Impact (DV)	Controlled 98th Percentile Impact (DV)	98th Percentile Improvement (DV)	98th Percentile Improvement (%)	Cost Effectiveness ($/DV)
Mingo	1.01	0.87	0.14	13.9	$28,092,971
Hercules	0.81	0.72	0.09	11.1	$43,700,177
Buffalo	0.61	0.48	0.13	21.3	$30,253,969
Control Type **DLS-20%** Class I Area	Base 98th Percentile Impact (DV)	Controlled 98th Percentile Impact (DV)	98th Percentile Improvement (DV)	98th Percentile Improvement (%)	Cost Effectiveness ($/DV)
Mingo	1.01	0.87	0.14	13.9	$105,179,459
Hercules	0.81	0.70	0.11	13.6	$133,864,766
Buffalo	0.61	0.48	0.13	21.3	$113,270,187

Based on the five step analysis outlined by EPA, this analysis demonstrates that the cost of compliance associated with WLS, Fuel Substitution with low sulfur PRB coal, and DLS is extremely high on a $/ton of SO_2 removed basis, and especially on a $/DV of improvement basis, and is not economically feasible, especially if the cost per ton of clinker produced is taken into account. Fuel Substitution with a regional 3.0 percent sulfur coal, resulting in a 23 percent reduction in SO_2 emissions, is economically feasible and is being proposed as BART.

Holcim proposes that BART for SO_2 for the Holcim Clarksville Kiln is fuel substitution or equivalent technologies that will achieve a 23 percent reduction in the maximum daily SO_2 emission rate of 117,345 lbs.

To comply with this determination, Holcim is proposing an enforceable limit of 23% reduction in the maximum daily SO_2 emission rate of 117,345 lbs used for modeling visibility impairment. As documented throughout this report, fluctuations in daily kiln operations and inputs, and the uncertainty in predicting the daily absorption of sulfur in the clinker, Holcim proposes that the enforcement of the reduction be based on a 30 day rolling average.

In Portland cement kilns, the NO_x that is generated is primarily classified into one of two categories, i.e., thermal NO_x or fuel NO_x[10]. Thermal NO_x occurs as a result of the high-temperature oxidation of molecular nitrogen present in the combustion air. Fuel NO_x is created by the oxidation of nitrogenous compounds present in the fuel. It is also possible for nitrogenous compounds to be present in the raw material feed and become oxidized to form additional NO_x referred to as feed NO_x.

Due to the high flame temperature in the burning zone of the rotary kiln (3400° F), NO_x emissions from the kiln tend to be mainly comprised of thermal NO_x. Although NO_x emissions from cement kilns include both nitrogen oxide (NO) and nitrogen dioxide (NO_2), typically, less than 10% of the total NO_x in the flue gas is NO_2.[11]

The kiln is the only BART source which emits NO_x, thus a NO_x BART evaluation was performed only for the kiln. The maximum actual 24-hour kiln NO_x emission rate that was modeled for the BART applicability determination is summarized in Table 4-1. The NO_x 24-hour maximum actual emission rate was determined from analyzer data for November 24, 2007.

TABLE 5-1. EXISTING ACTUAL MAXIMUM 24-HOUR NO_X EMISSION RATES

	NO_x 24-Hour Emission Rate ton/24-hr	NO_x Hourly Equivalent Emission Rate lb/hr
Kiln	36.59 (73,185 lbs)	3,049

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. A list of control technologies was obtained by reviewing the U.S. EPA's Clean Air Technology Center, control equipment vendor information, publicly-available air permits, applications, and technical literature published by the U.S. EPA and the RPOs.

The available retrofit NO_X control technologies are summarized in Table 5-2.

[10] NO_X Formation and Variability in Portland Cement Kiln Systems, Penta Engineering, December 1998.

[11] IBID.

TABLE 5-2. POSSIBLE NO_X CONTROL TECHNOLOGIES

Kiln Control Technologies
Low NO_X Burner
Flue Gas Recirculation
CKD Insufflation
Mid-Kiln Firing of Tires
Selective Noncatalytic Reduction
Selective Catalytic Reduction

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 IN THE ROTARY KILN

Low NO_x burners (LNBs) reduce the amount of NO_x formed at the flame. The principle of all LNBs is the same: stepwise or staged combustion and localized exhaust gas recirculation (i.e. at the flame). As applied to the rotary cement kiln, the low-NO_X burner creates primary and secondary combustion zones at the end of the main burner pipe to reduce the amount of NO_x initially formed at the flame. In the high-temperature primary zone, combustion is initiated in a fuel-rich environment in the presence of a less than stoichiometric oxygen concentration. The oxygen-deficient condition at the primary combustion site minimizes thermal and fuel NO_X formation and produces free radicals that chemically reduce some of the NO_X that is being generated in the flame.

In the secondary zone, combustion is completed in an oxygen-rich environment. The temperature in the secondary combustion zone is much lower than in the first; therefore, lower NO_X formation is achieved as combustion is completed. CO that has been generated in the primary combustion zone as an artifact of the sub-stoichiometric combustion is fully oxidized in the secondary combustion zone.

Low-NO_X burners are considered to be a technically feasible option for NO_X control. As Holcim already has a LNB, the technology will not be considered further.

5.2.2 FLUE GAS RECIRCULATION

Flue gas recirculation involves the use of oxygen-deficient flue gas from some point in the process as a substitute for primary air in the main burner pipe in the rotary kiln. Flue gas recirculation (FGR) lowers the peak flame temperature and develops localized reducing conditions in the burning zone through a significant reduction of the oxygen content of the primary combustion "air." The intended effect of the lower flame temperature and reducing conditions in the flame is to decrease both thermal and fuel NO_X formation in the rotary kiln.

While FGR is a practiced control technology in the electric utility industry, Holcim is not aware of any attempt to apply FGR to a cement kiln because of the unique process requirements of the industry, i.e., a hot flame is required to complete the chemical reactions that form clinker minerals from the raw materials. The process of producing clinker in a cement kiln requires the heating of raw materials to about 2700°F for a brief but appropriate time to allow the desired chemical reactions that form the clinker minerals to occur. A short, high-temperature flame of about 3400°F is necessary to meet this process requirement. The long/lazy flame that would be produced by FGR would result in the production of lower or unacceptable quality clinker because of the resulting undesirable mineralogy. Clinkering reactions must take place in an oxidizing atmosphere in the burning zone to generate clinker that can be used to produce acceptable cement. FGR would tend to produce localized or general reducing conditions that also could detrimentally affect clinker quality. Due to these important limitations on the application of FGR and the lack of a successful demonstration on a cement kiln in the United States, FGR is not a technically feasible control option for NO_X control at this time.

5.2.3 CEMENT KILN DUST INSUFFLATION

Cement kiln dust (CKD) is a residual byproduct that can be produced by any of the four basic types of cement kiln systems. CKD is most often treated as a waste even though there are some beneficial uses. However, as a means of recycling usable CKD to the cement pyroprocess, CKD sometimes is injected or insufflated into the burning zone of the rotary kiln in or near the main flame. The presence of these cold solids within or in close proximity to the flame has the effect of cooling the flame and/or the burning zone thereby reducing the formation of thermal NO_X. The insufflation process is somewhat counterintuitive because a basic requirement of a cement kiln is a very hot flame to heat the clinkering raw materials to about 2700° F in as short a time as possible. The Clarksville plant already uses this technology and it is already included in the baseline. Therefore, this option is removed from consideration for BART.

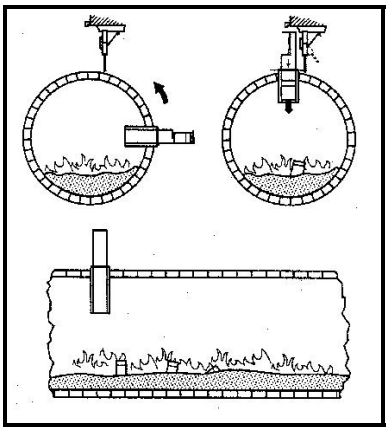
5.2.4 MID-KILN FIRING OF SOLID FUEL WITH MIXING AIR FAN

Secondary combustion is defined as follows: a portion of the fuel is fired in a location other than the burning zone. This reduces thermal NO_x generation because the temperature in the secondary combustion zone is less than 2100 °F. Mid-kiln firing (MKF) of solid fuels is an example of secondary combustion and includes fuels such as used tires, oil filter fluff, plastics, spent activated carbon and carbon black, asphalt shingles, diaper manufacturing waste, and other combustible solids. MKF improves clinker process energy efficiency, allows for greater operational flexibility with respect to fuel types, and is currently listed as a NOx control technology in 10 CSR 10-6.380 Control of NOx Emissions from Portland Cement Kilns.

An example of a MKF system is the Cadence feed form MKF technology which was first introduced in 1989. It is comprised of three primary components: (1) a staging arm or "feed fork," that picks up the fuel modules and positions them for entry into the kiln, (2) two pivoting doors that open to allow the fuel to drop into the kiln, and (3) a drop tube that

extends through the side wall of the kiln. In addition to these basic components, feed fork technology also requires a delivery system which positions the fuel models so they can be picked up by the feed fork and a mechanism for opening the doors so the fuel can enter the kiln. Due to rotation of the kiln, fuel can only be injected once per revolution from the top, as shown in Figure 5-1.

FIGURE 5-1. MID-KILN FIRING SCHEMATIC[12]



High-pressure air, in the range of a 2-10 percent replacement of the primary combustion air, could be injected through the shell of the rotary kiln and into the calcining zone to where a mixing air fan mixes the air with the gas and fuel within the rotary kiln for more complete combustion of the solid fuel.

By adding fuel mid-kiln, MKF changes both the flame temperature and flame length. These changes should reduce thermal NO_X formation by burning part of the fuel at a lower temperature and by creating reducing conditions at the mid-kiln fuel injection point which may destroy some of the NO_X formed upstream in the kiln burning zone.

Clarksville has the largest long kiln in the world. The kiln has a 7 meter diameter and a very high thermal capacity. Using whole tires to replace 10% of total fuel consumption will require four whole tires being fed to the mid-kiln door per kiln revolution, 12% fuel replacement would require 5 tires per revolution. The maximum tire feed rate per revolution that Holcim is aware of, on similar applications, is three tires per revolution. Holcim is concerned that the greater the number of tires fed per revolution, on a continuous basis, the greater the potential for process upsets from unstable feeding. Holcim has found that kilns being fed even one to three tires per revolution can have problems with stable, uniform feeding. In addition, if too many tires burn at the bottom of the kiln, a high local temperature could result which would disturb the normal operation of the kiln and potentially increase NOx. Further, due to the large kiln diameter, the reducing zone created by burning tires may only impact a small cross section of the entire cross section of the kiln, thus having less of an overall reduction in NOx than anticipated.

[12] 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.

In an effort to better understand these uncertainties, Holcim hired CINAR Company, the expert in this field, to conduct modeling of the system and to predict NOx reduction. Their study predicted that a 15% NOx reduction would occur at 10% replacement (replace 10% of the current fuel with tires) and 27% NOx reduction for 15% replacement.

To then determine the thermal substitution rate (TSR) of tires that the Clarksville plant is capable of utilizing, three additional factors must be considered:

1. Tire availability. The local market only has sustainable resources of 10-12% TSR;
2. Tire feeding limit: 12% TSR equates to five tires being fed per revolution.
3. The thermal stability of operation in a large kiln. 15% TSR is predicted to be the maximum for short term periods, whereas 10-12% TSR is predicted to be achievable on a long term basis.

Based on the lack of experience using MKF of tires on kilns the size of Clarksville, Holcim is relying on the computer modeling (regardless of the general uncertainty that exists with computer models) to estimate the NOx reduction. Holcim anticipates that MKF of tires may achieve up to 20% percent NOx reduction at a TSR of 12 percent on a long term basis.

Tires also have the benefit of a lower sulfur content (the Rubber Manufacturers Association reports a value of 1.83 percent) relative to the current coal/coke used. However, without conducting testing, it is unknown if utilizing tires at the mid-kiln location will result in the same reduction in SO_2 emissions predicted for reductions in fuel sulfur. Consequently, a reduction in SO_2 emissions from the use of tires was not considered further.

MKF is considered to be a technically feasible option for NOx control. Further, Holcim has already received a construction permit that would allow the installation of MKF, whereas other technologies would require a new construction permit application process, the result of which is unknown.

5.2.5 SELECTIVE NONCATALYTIC REDUCTION

In the relatively narrow temperature window of 1600 to 1995°F, ammonia (NH_3) reacts with NO_x without the need for a catalyst to form water and molecular nitrogen in accordance with the following simplified reactions.

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

As applied to NO_x control from cement kilns and other combustion sources, this technology is called selective noncatalytic reduction (SNCR). Above this temperature range, the NH_3 is oxidized to NO_x thereby increasing NO_x emissions. Below this temperature range, the reaction rate is too slow for completion and unreacted NH_3 may be

emitted from the pyroprocess. This temperature window generally is available at some location within the rotary kiln. The NH_3 could be delivered to the kiln shell through the use of anhydrous NH_3, or an aqueous solution of NH_3 (ammonium hydroxide) or urea.

A concern about application of SNCR technology is the breakthrough of unreacted NH_3 as "ammonia slip" and its subsequent reaction in the atmosphere with SO_2, sulfur trioxide (SO_3), hydrogen chloride (HCl) and/or chlorine (Cl_2) to form a detached plume of sub-micron particles. As NH_3 or Urea injection rates are increased, to attempt to achieve higher levels of reduction, NH_3 emission levels are increased.

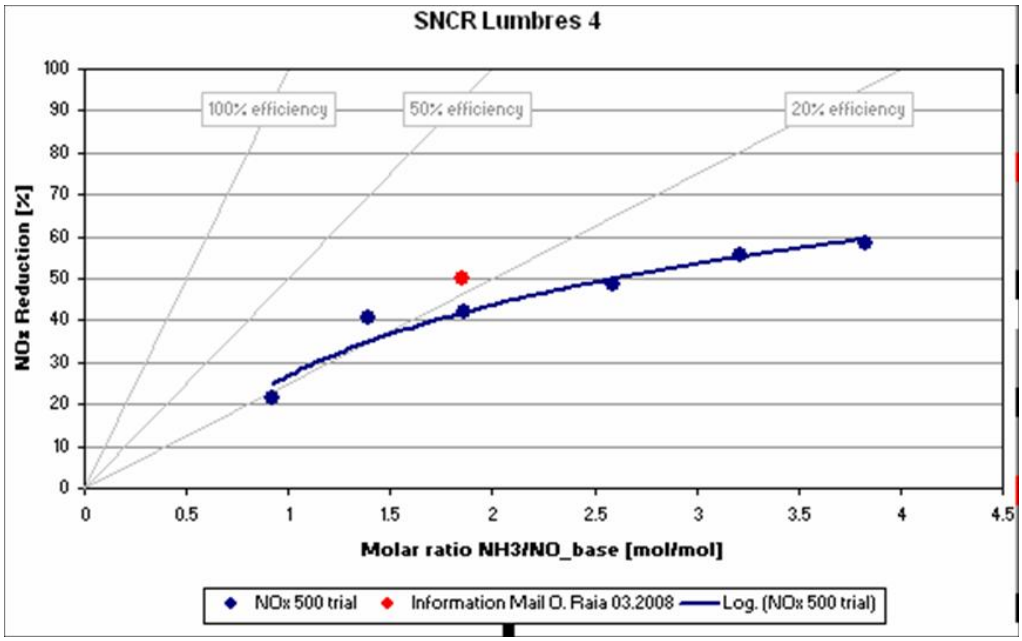
Industry Experience

Ash Grove Cement Company installed a full scale SNCR system on one of its wet kilns in Midlothian, Texas. Ash Grove has reported that it is achieving a 35 to 40% NOx reduction; however, as this application has just started, no data is available to verify this reduction is being achieved or on what averaging period or the long term sustainability.[13]

Holcim's wet plant in Lumbres, France utilizes SNCR. It is the earliest application of SNCR on a long kiln in the world and has been running for multiple years. The plant has found that NH_3 slip increases as the urea injection rate increases especially when the molar ratio is more than 1.0 (i.e. the NH_3 added is more than needed for the reaction). At this level, significant amounts of NH_3 are unreacted. The plant reports achieving 20 percent NOx reduction at a 1.0 molar ratio of NH_3/NOx and 40 percent at a molar ratio of 1.5 as shown in Figure 5-2.

[13] BART Five Factor Analysis. Ash Grove Cement Company Montana City, Montana. Dated June 2007. Page 5-9.

FIGURE 5-2. NOX REDUCTION VERSUS NH3 MOLAR RATIO OBSERVED AT HOLCIM LUMBRES PLANT.



However, at 20 percent NOx reduction, the NH_3 slip is reported to be 10 mg/m3, while at 40 percent reduction, the NH_3 slip can be 20 – 30 mg/m^3 (a 50 percent to 100 percent increase). Based on experiences at many cement plants with SO_2 and HCl in the exhaust gas, which is also the case for the Clarksville plant, a 20 mg/Nm3 NH_3 increase would cause a severe increase in plume visibility. The Lumbres plant is also smaller than Clarksville, having a diameter of only 3.3 meters versus Clarksville's 7 meter diameter kiln. The larger diameter of Clarksville's kiln would make distribution of the reagent across the kiln more difficult, and would reduce the effectiveness to an unknown degree.

NO_X reductions from SNCR systems can vary considerably based on site specific conditions, most notably being the type of kiln. For example, the NO_X reduction at the long wet kiln at Lumber is lower at a given ammonia molar ratio than observed at similar size preheater/pre-calciner (PH/PC) kilns. Some of the reasons for this lower relative NO_X reduction include:

- In a long wet kiln, the NH_3 is sprayed in the kiln itself, rather than being sprayed in the ductworks in a PH/PC kiln. A kiln's diameter is much larger than the ductwork diameter which makes it more difficult for the liquid NH_3 to be evenly distributed across the entire cross section of the gas stream.
- Studies have shown that in long kilns, the gas stream can be highly stratified over the cross section. The relatively heavy CO_2 released from the raw materials tends to stay on the top and bottom of the raw material bed, while lighter O_2 tends to float to the top of the kiln cylinder. This theory has been proven by many actual measurements at the plant. In contrast, the ductwork in PH/PC kiln systems are mostly vertical and this stratification is not observed, or is much less than in the

horizontal kiln system. The combination of stratification in the kiln cylinder, and less even distribution of NH_3, compound the problem of poor contact between the NH_3 and NO_X.

- The reaction of NH_3 and NO_X includes multiple steps that require O_2. In the areas of the long kiln that are lacking in O_2, the reaction rate is significantly lower, and thus NOx reduction is significantly lower relative to a well mixed gas stream.

Based on the concerns with NH_3 slip at high molar ratios, and the uncertainty regarding the level of effectiveness of the reagent in Clarksville's large diameter kiln, Holcim anticipates that at a molar ratio of about 1.0, an average annual control efficiency of 20 percent could likely be achieved without excessive NH_3 slip. However, a pilot study would need to be conducted to verify this. Regardless, SNCR is considered to be a technically feasible option for NO_X control.

5.2.6 SELECTIVE CATALYTIC REDUCTION

Selective Catalytic Reduction (SCR) is an add-on control technology for the control of emissions of the oxides of nitrogen (NO_x) from a combustion process. SCR has been successfully employed in the electric power industry. The basic SCR system consists of a system of catalyst grids placed in series with each other within a vessel that is located in a part of the process where the normal flue gas temperature is in the required range. An ammonia-containing reagent is injected at a controlled rate upstream of the catalyst grids that are designed to ensure relatively even flue gas distribution within the grids, to provide good mixing of the reagent and flue gas, and to result in minimum ammonia (NH_3) slip.[14] The NH_3 reacts with NO_X compounds (i.e., NO and NO_2) on the surface of the catalyst in equal molar amounts (i.e., one molecule of NH_3 reacts with one molecule of NO_X). Common reagents include aqueous NH_3, anhydrous NH_3 and urea [$(NH_2)_2CO$]. In the presence of the catalyst, the injected ammonia is converted by OH^- radicals to ammonia radicals (i.e., NH_2^-), which, in turn, react with NO_X to form N_2 and H_2O. The SCR catalyst enables the necessary reactions to occur at lower temperatures than those required for Selective Non-Catalytic Reduction (SNCR). While catalysts can be effective over a larger range of temperatures, the optimal temperature range for SCR is 570 - 750º F.

The catalyst system used in SCR applications usually consists of (1) a porous honeycomb of a ceramic substrate onto which catalyst has been attached to the surface of the ceramic material, or (2) a flat or corrugated plate onto which catalytic material has been deposited on the surface. A porous metal oxide with a high surface area-to-volume ratio acts as a catalyst base. On this base, typically titanium dioxide (TiO_2), one or more metal oxide catalysts are deposited in various concentrations. In SCR applications, the active catalyst material typically consists of vanadium pentoxide (V_2O_5), tungsten trioxide (WO_3), and molybdenum trioxide (MoO_3) in various combinations. The composition, also known as the catalyst formulation, is tailored by the catalyst vendor to best suit a particular SCR application. Catalyst deactivation through poisoning, fouling, masking, sintering and erosion are common problems for SCR catalysts that, without careful process design and

[14] Slip refers to the quantity of unreacted reagent that exits the SCR reactor.

operation, could be exacerbated. If not fouled by sulfur dioxide (SO_2), the catalysts used in SCR have a propensity to oxidize sulfur dioxide (SO_2) in the flue gas to sulfur trioxide (SO_3), a more undesirable pollutant.

Because the reaction rate of NH_3 and NO_X is temperature dependent, the temperature of the flue gas stream to be controlled is the most important consideration in applying SCR technology to any combustion source. The optimum temperature range for SCR application is about 300º C (570º F) to 450º C (840º F). This range of normal process temperature would occur within the kiln of a long wet kiln, rather than in the exhaust gas between the wet kiln and the PMCD inlet.

SCR has not been applied to any wet cement plant in the world and is not considered an available technology.

As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or 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: 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 licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available. An exception would be if the technology were proposed and permitted under the qualifications of an innovative control device consistent with the provisions of 40 CFR 52.21(v) or, where appropriate, the applicable SIP [in which case it would be considered available].

Therefore, SCR is eliminated from further consideration as BART for NO_x control at the Clarksville plant.

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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 presents potential NO_X technically feasible control technologies by effectiveness.

TABLE 5-3. RANKING OF TECHNICALLY FEASIBLE KILN NO_X CONTROL TECHNOLOGIES BY EFFECTIVENESS

Control Technology	Effectiveness NO_X Emissions Level (%)
MKF	20%
SNCR	20%
LNB, CKD Insufflation, and Synfuel	Already utilized at Clarksville

5.4 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step four for the BART analysis procedure 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 MKF

Cost of Compliance
Holcim anticipates that MKF and SNCR have relatively the same level of effectiveness. Because SNCR would require a pilot study to prove or verify the effectiveness of NOx reduction and the potential associated opacity issues due to ammonia slip (see Appendix B), Holcim is accepting the use of MKF as BART. As Holcim is accepting the most stringent control option available as BART, the cost of compliance is not required to be evaluated.

Energy Impacts and Non Air-Quality Impacts
There are no known adverse energy or non-air impacts from MKF. MKF of tires has the benefit of eliminating tires from landfills and illegal dumping. It also reduces CO_2 emissions (a Green House Gas) and reduces fossil fuel use.

Remaining Useful Life
The remaining useful life of the kiln does not impact the annualized costs of MKF because the useful life is anticipated to be at least as long as the capital cost recovery period, which would be 15 years.

5.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE NO_X CONTROLS

The final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rate with MKF. The existing emission rates and emission rates associated with MKF were modeled using CALPUFF. The existing emission rates are the same rates that were modeled for the BART applicability analysis. The NO_x emission rate associated with MKF

was the existing emission rate less an average reduction of 20 percent. The emission rate is summarized in Table 5-4.

TABLE 5-4. SUMMARY OF EMISSION RATES MODELED IN NO_X CONTROL VISIBILITY IMPACT ANALYSIS

Emission Rate Scenario	Emission Rate SO_2 (lb/hr)	NO_X (lb/hr)	PM_{10} (lb/hr)
MKF,	4,889	2,440	51.82
Base case – High 24 hr average	4,889	3,049	51.82

Comparisons of the 98th percentile existing visibility impacts and the visibility impacts based on MKF are provided in Table 5-5. The visibility improvement associated with MKF are also shown in Table 5-5; this was calculated as the difference between the existing visibility impairment and the visibility impairment for the remaining control options as measured by the 98th percentile modeled visibility impact.

TABLE 5-5. NO_X CONTROL VISIBILITY IMPACT ANALYSIS

	Existing 98% Impact (Δdv)	MKF 98% Impact (Δdv)	Improvement
Mingo	1.01	0.92	8.9%
Hercules	0.81	0.72	11.1%
Upper Buffalo	0.61	0.60	1.6%

As seen in Tables 5-5, the MKF option results in a visibility improvement of up to 11.1 percent in the Hercules Glades Class I area.

5.6 PROPOSED BART FOR NO_X

Based on the five step analysis outlined by EPA, MKF was identified as the highest ranking feasible add-on control technology. Energy and environmental impacts were assessed for this technology and the visibility improvements were evaluated against existing conditions. Consistent with EPA guidance, economic impacts were not assessed as Holcim was willing to utilize the highest ranked control technology. The visibility impact analysis demonstrates that the utilization of MKF to achieve a 2,440 lb/hr NO_x emission rate results in up to an 11.1 percent visibility improvement. Neither non-air quality nor energy impacts associated with this control technology eliminate it in favor of retaining the existing rates as BART.

Holcim has determined that BART for the Holcim Clarksville Kiln is the installation and operation of a Mid Kiln Firing (MKF) system or equivalent that will achieve a 20 percent reduction in the maximum daily NO_X emission rate of 73,185 lbs.

To comply with this determination, Holcim is proposing an enforceable limit of a 20% reduction in the maximum daily NO_X emission rate of 73,185 lbs used for modeling visibility impairment. As documented in this report, the dynamics in daily kiln operations and inputs and the lack of

information on predicting short term actual reductions from MKF, Holcim proposes that the enforcement of the reduction be based on a 30 day rolling average.

Based on the lack of site specific, or significant industry data, for the use of this technology on wet cement kilns, it is possible that Holcim will further evaluate the MKF system and determine that MKF results in limited or no additional benefit. In the future, an alternative technology or methodology may become feasible and could be implemented as needed. Holcim will continue to utilize the NOx controls that are already in place, including LNB, insufflation, and the use of alternative fuels as available.

Based on the five-step analysis, Holcim proposes the following as BART:

Kiln:

- PM_{10} – Holcim has determined that the existing electrostatic precipitator constitutes BART. This control device is effective for controlling PM_{10} from a wet kiln.

- NO_X – Holcim has determined that BART for the Holcim Clarksville Kiln is the installation and operation of a Mid Kiln Firing (MKF) system or equivalent that will achieve a 20 percent reduction in the maximum daily NO_X emission rate of 73,185 lbs.

- SO_2 – Holcim proposes that BART for the Holcim Clarksville Kiln is fuel substitution or equivalent that will achieve a 23 percent reduction in the maximum daily SO_2 emission rate of 117,345 lbs.

The proposed BART control strategies will result in reductions of the visibility impacts attributable to the Clarksville plant. A summary of the visibility improvement at Class I areas based on the existing emission rates and proposed BART emission rates is provided in Table 6-1.

TABLE 6-1. VISIBILITY IMPAIRMENT IMPROVEMENT

	Mingo National Wildlife Refuge	Hercules Glades Wilderness Area	Upper Buffalo Wilderness Area
Existing 98% Impact (Δdv)	1.01	0.81	0.61
BART 98% Impact (Δdv)	0.79	0.64	0.48
Improvement 98% Impact (Δdv)	22%	21%	22%

Holcim proposes to implement BART on or before 5 years after EPA approval of Missouri's Regional Haze Rule State Implementation Plan as per 40 CFR 51 Appendix Y. Because the actual implementation date is at least 5 years from the date of this document, Holcim requests that it not be bound to the technologies reviewed during this analysis, but to the percent reductions stated in the report. Changes in technology may offer opportunities to obtain even better reductions with lower cost impact.

Due to the variability in kiln operation and inputs as referenced in the report, Holcim proposes to comply with an enforceable limit of 23% reduction in SO2 emissions and 20% reduction in NOx emissions from the daily maximum emission rates, as modeled, on a 30 day rolling average.

APPENDIX A. COAL COMPOSITION DATA

Appendix A. Coal Composition Data - Holcim Clarksville BART Analysis Options:

	Regional Coals		PRB Coal	
Area	**Illinois**	**Illinois**	**Colorado**	
Company **Mine name**	**Peabody COALSALES LLC** **Gateway Mine**	**Knighthawk** **KHC Mines, primarily Pairie Eagle Mine**	**COALSALES LLC** **Twentymile Mine**	
		FOB Lone Eagle (KHC Dock, Mile post 105)	**Rail:** Energy, CO to Cora, IL via UP Rail **Barge:** Cora, IL to Clarksville	
Transportation Mode	**Barge**	**Truck & Barge**	**0.7% Sulfur Coal**	
Sulfur %	2.83%	3.00%	0.70%	**Sulfur %**
Ash %	8.60%	8.50%	10.00%	**Ash %**
Volatiles %	35.50%	37.00%	34.40%	**Volatiles %**
Moisture %	13.50%	12.50%	10.00%	**Moisture %**
Hydrogen %	5.00%	5.20%	5.00%	**Hydrogen %**
HGI	52	55	45	**HGI**
Chlorine %	0.12%	0.05%	0.01%	**Chlorine %**
mmbtu/lb	11,000	11,100	11,300	**mmbtu/lb**
HHV MJ/MT	25,582	25,814	26,279	**HHV MJ/MT**
LHV MJ/MT	25,567	25,800	26,266	**LHV MJ/MT**
Ultimate (Dry)				**Ultimate (Dry)**
Ash %	9.90%	9.00%	11.00%	Ash %
Hydrogen	5.00%	5.20%	5.00%	Hydrogen
Total Carbon	71.40%	72.00%	69.60%	Total Carbon
Nitrogen	1.30%	1.40%	1.70%	Nitrogen
Sulfur	3.28%	3.10%	0.54%	Sulfur
Chlorine	0.12%	0.04%	0.01%	Chlorine
Oxygen	9.00%	9.40%	10.75%	Oxygen
Ash Mineral (Dry)				**Ash Mineral (Dry)**
Silicon Dioxide	51.40%	50.70%	60.00%	Silicon Dioxide
Aluminum Oxide	19.70%	20.50%	25.10%	Aluminum Oxide
Titamium Dioxide	1.00%	1.00%	0.90%	Titamium Dioxide
Calcium Oxide	4.20%	3.50%	4.00%	Calcium Oxide
Iron Oxide	16.30%	15.80%	3.10%	Iron Oxide
Magnesium Oxide	1.00%	1.00%	1.40%	Magnesium Oxide
Potassium Oxide	2.20%	2.20%	1.30%	Potassium Oxide
Sodium Oxide	1.30%	0.70%	1.20%	Sodium Oxide
Sulfur Trioxide	2.60%	2.70%	1.50%	Sulfur Trioxide
Phos Pentoxide	0.20%	0.20%	0.90%	Phos Pentoxide
Strontium Oxide	0.10%		0.20%	Strontium Oxide
Barium Oxide	0.10%		0.40%	Barium Oxide
Manganese Oxide	0.10%	0.10%	0.10%	Manganese Oxide
Vanadim Pentroxide				
Nickel Oxide				
Undetermined		1.80%		

APPENDIX B. REVIEW OF THE POTENTIAL FOR PLUME OPACITY EXCEEDANCES RESULTING FROM THE USE OF A WET SCRUBBER

Appendix B. Review of the Potential for Plume Opacity Exceedances Resulting from the Use of a Wet Scrubber.

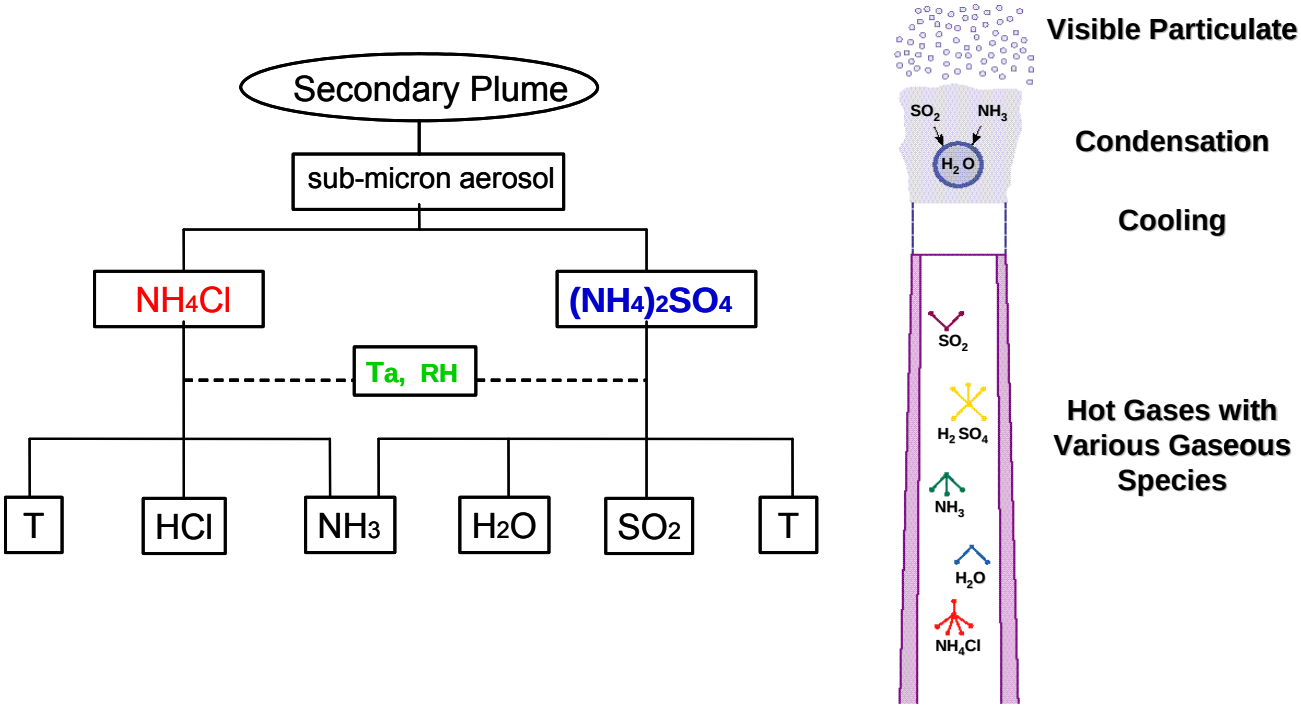
Nianzhi Wang, MPC-E

In the BART analysis for Holcim's Clarksville (CV) facility, a wet scrubber has been evaluated as a BART control option for SO_2. Although, a scrubber was shown to be technically feasible, it was also determined that reheating of the exhaust gas would be necessary to avoid a detached/attached plume. Following is an analysis of the gas stream to determine the specific temperature needed for the plume reheating requirement. The kiln system is currently controlled by an ESP and currently has an outlet gas temperature of approximately 380 deg F.

<u>Background - The plume problem in cement manufacturing process</u>

To evaluate the reheating requirement, we have to briefly introduce the plume problem in cement plants and potential risk of a visible plume after the scrubber.

The following figure shows the chemical reactions for most common types of plume in the cement manufacturing process, Although SO_3 and Total Hydrocarbons (THC) may also contribute to the plume, they have not been considered.



T = Stack Temperature, RH = Ambient Relative Humidity, Ta = Ambient Temperature

Some of the key points relevant to the diagram include:

- Both $(NH4)_2SO4$ and NH_4Cl are sub-micron aerosols that form at relatively low stack temperatures. $(NH4)_2SO4$ formation needs condensed moisture to occur. Whereas NH_4Cl solid can quickly form directly from the gas phase of NH_3 and HCl although with condensed moisture the reaction rate will be much faster.
- Sub-micron aerosols are similar in size to the wave length of light and thus strongly scatter the light and block light transmission through the stack gas. Figure 1 provides an example of relative light extinction versus particle size. For example, a $PM_{0.5}$ particle has an extinction efficiency approximately an order of magnitude greater than that of PM_{10}.

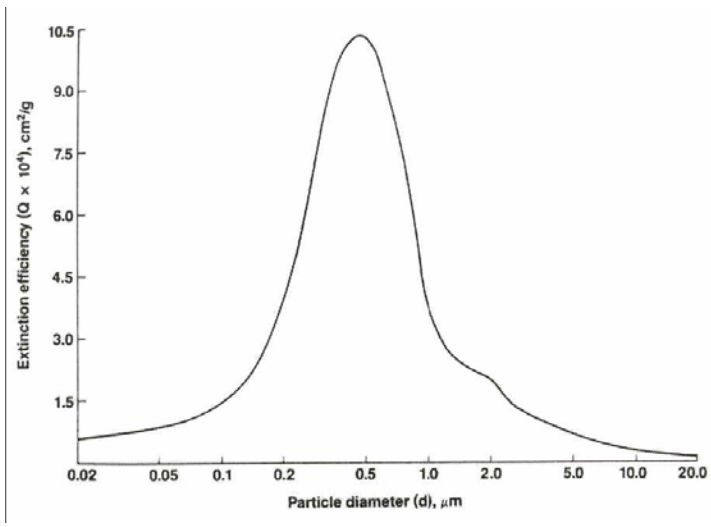


Figure 1. Extinction Efficiency Factor Verses Particle Diameter.

- The particle light extinction efficiency factor indicates the total light flux scattered and absorbed by a particle. Aerosols in the 0.2 - 1.0 μm diameter range are particularly effective in scattering visible light (wavelength: about 0.4 - 0.7 μm) on a unit mass basis, with a peak attenuation at 0.5 μm.

- The particles of either very large (>5 μm) or very small (<0.1 μm) diameter are much less effective in light attenuation.

- Plume aerosols usually form outside of the stack when the gas temperature is quickly cooled down and moisture is condensed, but the precursors have not had sufficient time to be diluted with ambient air. This situation is most dominant in occurrence on cold, calm and humid days.

Supplement A, at the end of this document, contains examples of historical visible plume problems in the cement industry and related studies.

Problems Associated with Using a Wet Scrubber on the Clarksville Kiln Exhaust Gas (in-stack)

- If a wet scrubber is installed after the Clarksville kiln, the kiln gas will need to be quenched and cooled down to the dew point temperature at the inlet of the scrubber (a similar condition of gas cooling in the presence of high humidity that can occur at the exit of a stack). If the gas has NH_3 and HCl, they can quickly react to form aerosols (fine particulate matter). These very fine particulates are controlled with a much lower efficiency than larger PM and thus can increase PM levels of the form of PM that leads to the highest plume visibility.

- In addition, the scrubber can not remove all NH_3 or SO_2 in the gas stream. The typical SO_2 reduction in a scrubber is about 90%. The NH_3 removal is governed by the equilibrium between the gas and the scrubber slurry liquid. Figure 2 provides the NH_3 gas-liquid equilibrium graph at a pH of 6. The NH_3 remaining in the effluent can be up to 10 ppm depending on the type of scrubber, the pH set point in the scrubber, and the scrubber influent NH_3 concentration. The remaining SO_2 and NH_3 in the scrubber effluent could react with the NH_4Cl aerosols already present in the gas and further increase plume visibility.

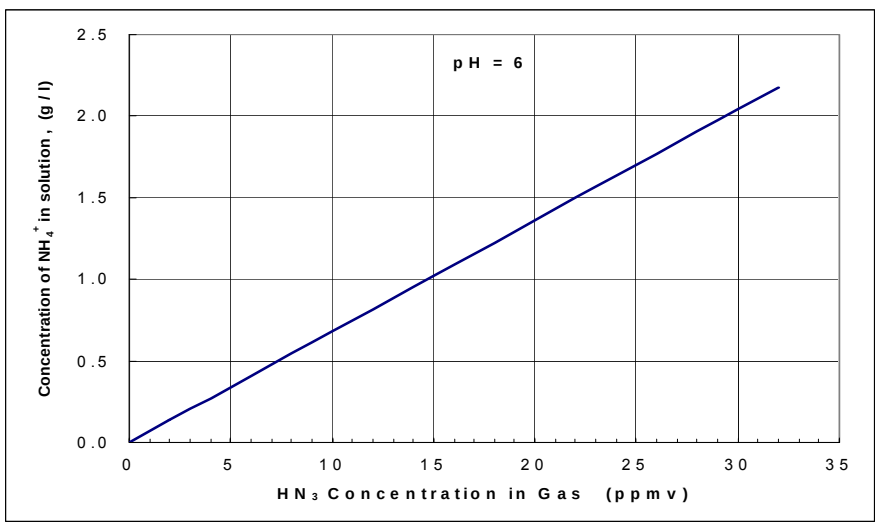


Figure 2. Concentration of NH_4^+ versus HN3 Concentration in Gas

- The gas temperature after the scrubber is much lower than the kiln gas temperature. Besides the aerosols formed at the inlet of the scrubber, more aerosols may also form in the cold and wet stack, and therefore, increase opacity.

Several scrubber vendors have confirmed the above phenomena with scrubber use:

- As an example, a vendor evaluated building a wet scrubber for one of Holcim's PH/PC plants. A PH/PC kiln system typically has two gas effluent streams, one contains high NH_3 (main stack) and the other contains high HCl (by-pass stack). Usually, both streams are introduced to a control device at the same inlet,

However, in this situation, the vendor provided the following concerns/comments in doing so as part of a feasibility study for the plant[1]:

> *"Mixing the NH_3 and HCl streams at the inlet will indeed produce an NH_4Cl salt that will be submicron in size".*
>
> *"This will result in opacity, I am sure it will be greater than 20%. Once this salt is formed, it will be very difficult to remove. Therefore, the preferred treatment would be to absorb the gases before they have a chance to react".*
>
> *"As we discussed, the two separate gas streams can be treated with individual scrubbers. However, it would be less expensive to perform the scrubbing in a single, large vessel with two separate inlet barrel"*

The scrubber system was ultimately built by Monsanto. And, even though the problem was acknowledged, and the system was designed to prevent the visible plume problem, the plant still has challenges with plume formation during the winter.

<u>Kiln gas emission concentrations and opacity</u>

- Holcim, as well as other companies, have found that at about 5ppm NH_4Cl or 10ppm $(NH4)_2SO4$, detached plumes can form outside of the stack if the stack gas is not hot enough to allow for significant dilution prior to condensation or if it is a very cold day in winter. Both aerosols will form quickly when the stack gas is cooled down by very cold ambient air.

- Stack temperatures for wet kilns are typically about 350 F. PH/PC kilns have similar stack temperatures when their in-line raw mills are not running. During these periods, PH/PC kilns have also observed a higher frequency of visible plumes as the precursors, NH_3, HCl and SO2, are not absorbed in the in-line raw mill.

Some specific examples of plants with visible plumes caused by constituents with concentrations similar to those in the Clarksville plant include:

- The CEMEX plant at Cementos Guadalajara, a 4 stage PH/PC kiln, had a highly visible plume caused by NH_4Cl. To resolve the problem, the plant added two additional stages that increased pollutant adsorption (HCl emissions were reduced to 5 ppm) and the plume disappeared. The reported stack temperature is 260 C (500 deg. F) which is much hotter than that of Holcim's Clarksville plant. Further, Clarksville's long wet kiln does not have the benefit of the stages in the PH/PC kiln for enhanced adsorption.

---

[1] *Steven Meyer, product Manager of Monsanto Company. Letter to Holcim for feasibility study of wet scrubber project, 10/29/1998*

- Holcim's Mississauga plant had a highly visible plume during the winter until they eliminated condensed moisture formation by heating the gas and reducing the HCl concentrations to less than 3-5 ppm. Holcim's Clarksville kiln can have HCl concentrations much higher than 5 ppm as will be discussed in a following section.

- Holcim's Untervaz plant in Switzerland has a wet scrubber as well as high levels of HCl and NH_3 in the kiln gas, and they have reported visible plumes during the winter especially when the in-line raw mill is down and the pollutant concentrations are higher.

Impact of Temperature on Visibility – Reaction Rate Based Equations

Solid NH_4Cl aerosols can form directly from the gas phase through the following reversible chemical reaction when the temperature drops:

$$NH_4Cl\ (s) = HCl\ (g) + NH_3\ (g)$$

The thermodynamic criteria for the reaction to occur is determined by the equilibrium constant Kp, which can be expressed by the following equation[2]

$$\ln Kp = 34.266 - 21196/T$$

where T is the temperature (K). The chemical reaction takes place if the product of partial pressures of HCl and NH_3 in gas is greater than Kp, i.e. $(pHCl \cdot pNH_3) > Kp$ (pHCl & pNH_3 are both in atm). This reaction can keep going to form NH_4Cl until the partial pressures of NH_3 and HCl have dropped to a level such that their product is less than Kp.

If the CV plant utilized a wet scrubber, and we assume the scrubber inlet temperature after quenching is 170 deg F or 76.6 deg C, the Kp would be 3.6 E-12. In the kiln gas, concentrations as low as 1-2 ppm (1.0 E-06 - 2.0 E-6) NH_3 and HCl will make the $(pHCl \cdot pNH_3) > Kp$, and the reaction will not stop until both gas phases drop down to 1-2 ppm. Thus, almost all NH_3 and HCl with a concentration higher than 1-2 ppm in the kiln gas will form NH_4Cl aerosols in the scrubber.

Reheating the stack gas after the scrubber has two purposes:

1) Dissociate the newly formed NH4Cl solid

2) Prevent the formation of aerosols from NH_3 and HCl from forming again in the stack or near the stack. The higher the reheating temperature, the longer the

[2] P. Goldfinger, G. Verhaegen, "Stability of the Gaseous Ammonium Chloride Molecule", The Journal of chemical Physics, 50(1), 1467-1471 (1969)

gas has to disperse and be diluted with ambient air, so that the product of both NH_3 and HCl concentrations would not be higher than Kp, and no aerosol formation would occur.

An example of how reheating temperature affects the opacity in a power plant is depicted in Figure 3[3]. The precursor of the visible plume in this case is SO_3, (as opposed to NH_4Cl).

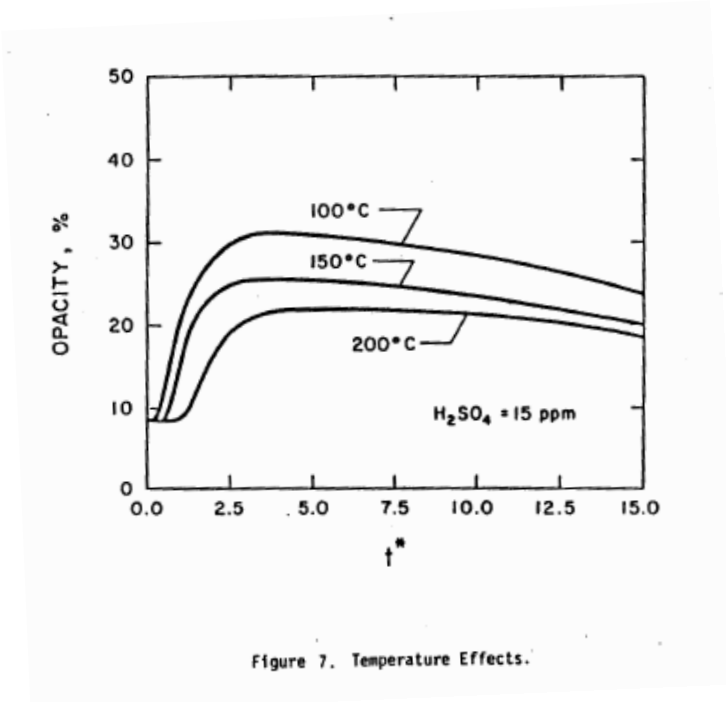


Figure 3. Gas Temperature Effect on Opacity Verses Time (t*)

Although reheating the stack gas to a temperature above the acid gas dew point may help to reduce corrosion problems and in-stack opacity, it may not be enough to avoid a plume outside of the stack. When the gas exits the stack, the temperature will quickly drop to below the acid dew point. Acid gas may be condensed, and acid water droplets may occur that will speed up other reactions in the liquid phase.

Figure 4 shows an example for stack gas containing SO_3. The gas temperature in the stack is much higher than the acid dew point, but once it goes out of the stack it takes only one second for the plume temperature T_P to drop below the dew point temperature T_{DP} and cause higher opacity levels.

[3] J. J. Martin Hughes, "Fine Particle Model for Detached Plume Opacity", Virginia State University, 16th Annual Meeting of the Fine Particle Society, April, 1985.

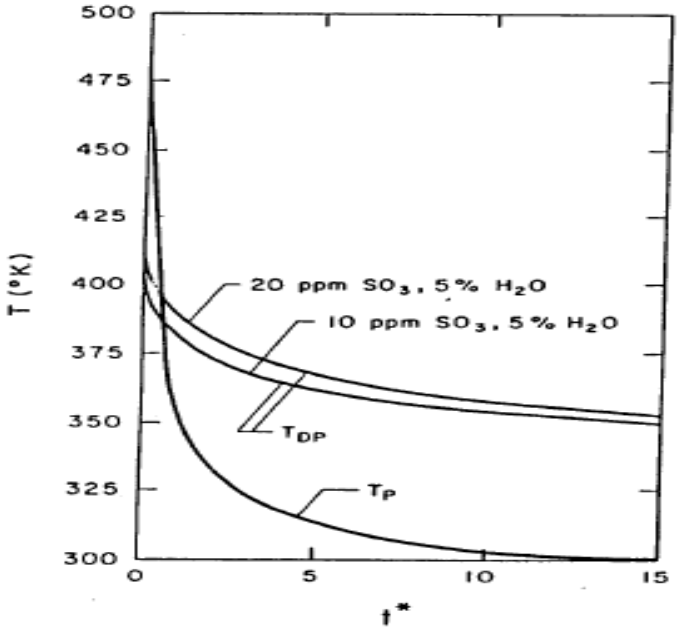


Figure 4. Stack gas temperature vs. Acid Dew Point and Time

Besides pollutant concentrations, other factors such as the stack gas temperature and moisture, the ambient air temperature and humidity, wind speed, sunlight and sky clarity, stack size and height effect plume visibility. Therefore, it is almost impossible to predict the exact reheating temperature required. Regardless, a mathematical model has been established to provide a simplified simulation of NH_4Cl formation outside of the stack based on the actual conditions at the CV plant.

Estimating the Reheat Temperature for CV based on Plant Data

The NH_3 and HCl emission concentration will control the plume formation as SO_2 concentrations are likely to be sufficiently high as to not be limiting in any equations. Table 1 summarizes the CV annual stack testing for 2002 - 2007. Although HCl was relatively low in 2007, it can and has varied significantly over the last five years.

Table 1. HCl and NH_3 Stack Test Data for Clarksville – 2002 thru 2007.

CV Emission		HCl		NH3
	ppmd	ppmw	ppmd	ppmw
2002	**12.8**	9.1	**36.2**	25.7
2003	**30.3**	21.5	**20.6**	14.6
2004	**26.9**	19.1	**27.1**	19.2
2005	**14.4**	10.3	**16.0**	11.5
2006	**8.0**	5.6	**22.5**	15.7
2007	**2.7**	1.9	**24.9**	17.6
Average	15.9	11.2	24.6	17.4

Please note that this data is from once per year stack testing not a Continuous Emission Monitor (CEM) and thus the annual and daily emission levels may vary considerably from these values. Further, the peak annual emission may be much higher than the test average. For example, during the three hours of stack tests in 2004, the maximum hourly HCl concentration was 70% higher than the minimum and 23% higher than the average.

Further, under current operations in 2007, the plant found that during some cold days, the plume outside of the stack was visible, but it did not reach 20% opacity.

The current stack temperature is about 350 F, and the temperature at the outlet of the ESP is about 380 F. The lower temperature in the stack is due to heat loss in the ductworks and the I.D. fan. Therefore, a reheating temperature of 380 F is proposed to maintain the current stack temperature of 350 F and eliminate the plume formation after the scrubber.

Using the 2007 stack test data (2 ppm HCl and 18 ppm NH_3), a reheat temperature of 380 F, or 350 F stack temperature, might not be necessary since based on our modeling result, the total HCl and NH_3 as aerosols after the scrubber should not be higher than in the original kiln gas.

However, HCl concentrations in the prior years have been as much as 10 times higher than 2007, reaching over 20 ppm in 2003 and 2004, while the NH_3 concentrations were nearly 20 ppm. These levels are considered to be highly probable of causing a visible plume at the current exhaust temperatures. Reviewing historical data, it was found that stack temperatures during these time periods were much higher than current temperatures. For example, the stack temperature was maintained at approximately 700 deg. F in 2003 and approximately 450 deg F (480 deg F at the outlet of the ESP) in 2004 (100 F higher than the proposed reheating temperature). The higher temperatures likely prevented significant visible plumes from occurring.

Regarding the use of a wet scrubber, even if some reduction in HCl occurred (such as 20%), the total HCl concentration after the scrubber would still be significantly higher than that in the kiln gas in 2007. Under this scenario, reheating to an ESP outlet of 380 F, or 350 F stack temperature, would likely not be sufficient to assure a stack opacity below 20% and additional re-heating would likely be required. Consequently, the proposed 380 F reheating temperature should be considered as an average for the year. That is, if the HCl and NH_3 concentrations reach 20 ppm in the kiln gas, the reheat temperature may need to be 480 deg F or higher in the winter, while if the HCl and NH_3 concentrations drop to 2007 levels or below, a reheat temperature of less than 380 deg F may be sufficient in the summer. Therefore, considering the variation in the HCl and NH_3 concentrations, an annual average reheat temperature of 380 deg F may be sufficient.

Is scrubbing half of the exhaust stream, and using the unscrubbed half for reheat, a viable option?

A scenario in which half or the exhaust gas stream is scrubbed, and the other half is not, followed by recombining the gas streams, was also considered. If feasible, this scenario would result in the unscrubbed gas providing the heat source to re-heat the scrubbed gas up to a temperature midway between the scrubbed gas temperature of approximately 170 deg F and the unscrubbed gas temperature of approximately 380 deg F, resulting in a mid-range temperature gas stream of approximately 275 deg F. Unfortunately, as discussed previously, the variability in precursor pollutant (HCl and NH_3) concentrations would most certainly lead to a visible plume at this low temperature and re-heating would continue to be required up to the originally identified average temperature of 380 deg F. This option was one of the scenarios evaluated in the modeling exercise discussed in the following sections.

Mathematical analysis of the impact of reheating temperature on CV visible plume

Using the equation described previously,

$$\ln Kp = 34.266 - 21196/T$$

a mathematical model was established to simulate NH_4Cl formation outside of the stack. Based on Holcim's experience with visible plumes at multiple plants, an NH_4Cl aerosol concentration of 5ppm in the atmosphere is used as the criteria for a highly visible plume outside of the stack. In reality, some of Holcim's plants control their NH_4Cl aerosol concentrations to less than 1-3 ppm to avoid visible plume formation.

This model only considers the gas temperature reduction due to mixing with ambient air and does not consider any reduction due to radiation. Thus, the actual condition will be worse than what the model predicts.

NH_4Cl formation was simulated for the following scenarios:

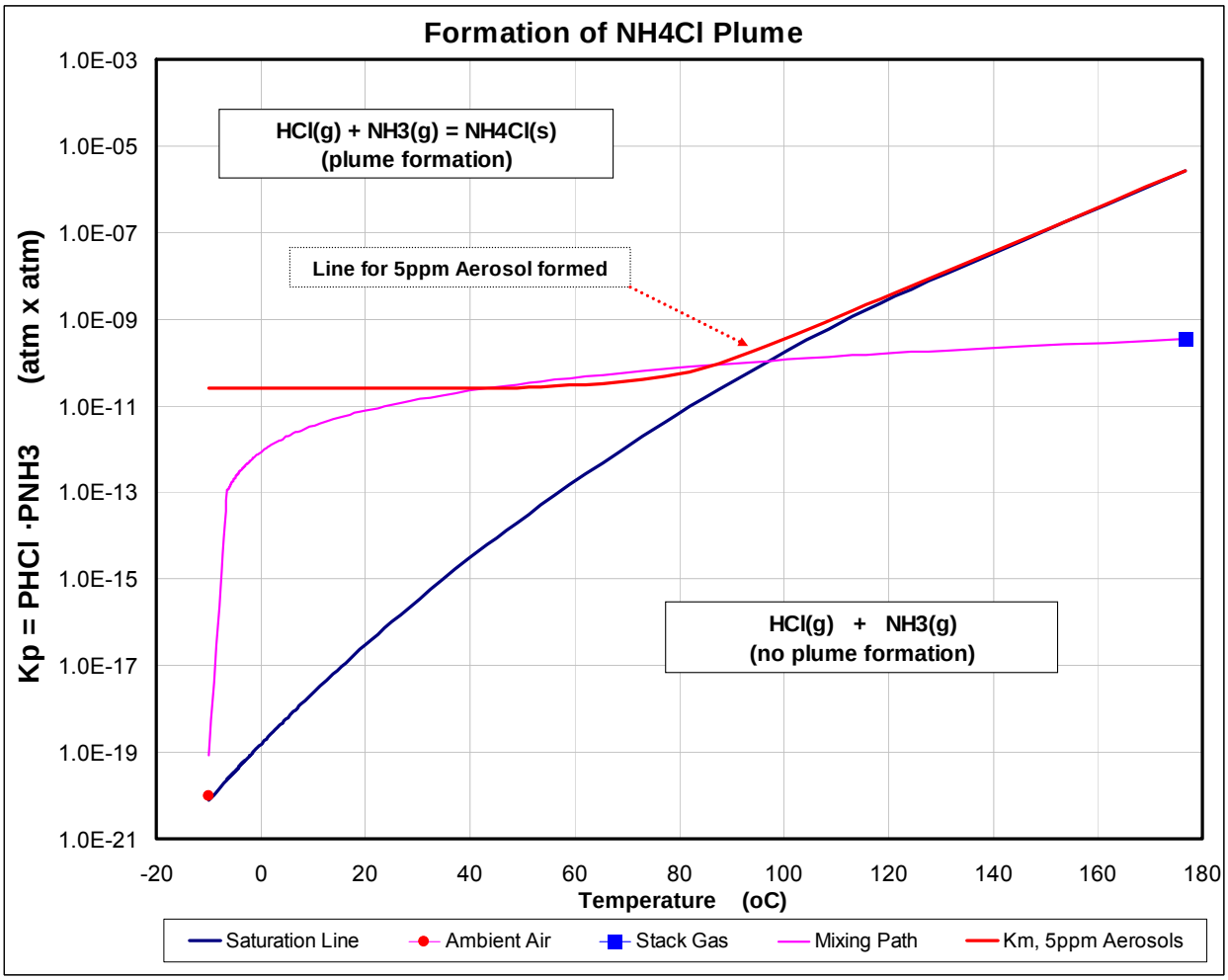
- Scenario 1. Maximum stack testing NH_3 and HCl concentrations for the last 4 years, reheating to 380F and Winter Condition
- Scenario 2. Maximum stack testing NH_3 and HCl concentrations for the last 4 years, reheating to 380F and Summer Condition
- Scenario 3. Maximum stack testing NH_3 and HCl concentrations for the last 4 years, reheating of 50% kiln gas (300F) and Winter Condition
- Scenario 4. Maximum stack testing NH_3 and HCl concentrations for the last 4 years, reheating of 50% kiln gas (300F) and winter Condition
- Scenario 5. Average of the NH_3 and HCl concentrations for the last 4 years, reheating of 50% kiln gas (300F) and winter Condition

- Scenario 6. Average of the NH_3 and HCl concentrations for the last 4 years, reheating of 50% kiln gas (300F) and summer Condition
- Scenario 7. Average of the NH_3 and HCl concentrations for the last 4 years, reheating of 380 F and summer Condition
- Scenario 8. Maximum stack testing NH_3 and HCl concentrations for the last 4 years, reheating to 480F and Winter Condition

Additional Model Assumptions/Calculations:

The model assumes that in each interval 50% of the original stack gas volume will be diluted with ambient air. Based on this dilution, and with respect to the ambient and stack gas specific heat, the temperature of the mixture will be calculated. Next, the Kp line which represents the equilibrium condition is drawn by inserting the temperature in the above formula. The corresponding concentration of HCl and NH_3 of the gas mixture is calculated at each interval, converted to partial pressures and multiplied with each other to find the Mixing Path value (Km). The Mixing Path (Km) at the corresponding temperature represents the calculated gas conditions at that interval. Then the Km+5 line which corresponds to the concentration of NH_3 and HCl that will result in the formation of at least 5 ppm of aerosols is drawn,. At any point that the Mixing Path and Km+5 lines cross each other at least 5 ppm of aerosols has been formed.

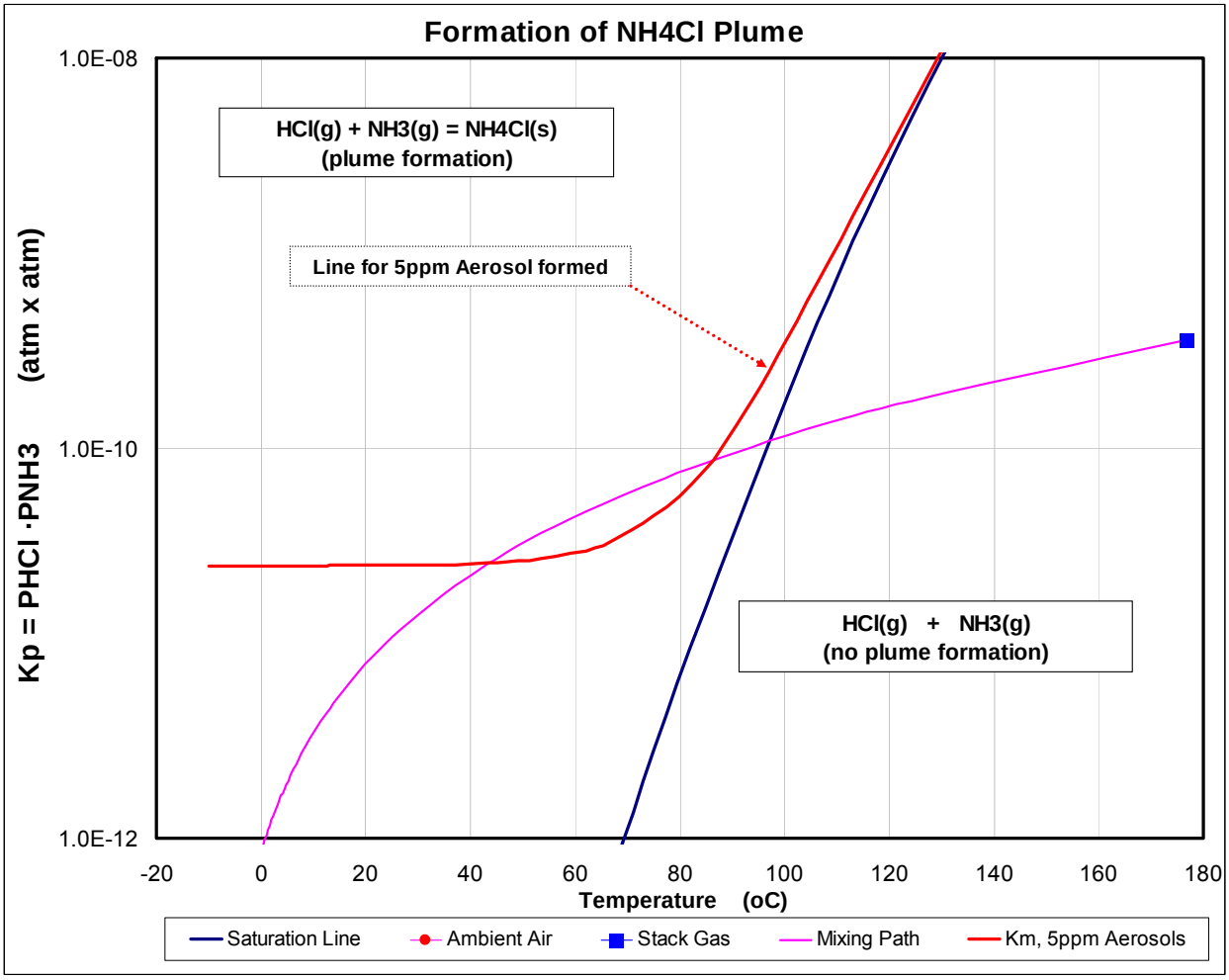
Scenario 1 (Figure 5) represents the 380°F reheating temperature and stack temperature of 350°F, an ambient temperature of 14°F (representing a typical winter temperature), and the five year maximum NH_3 and HCl concentrations of 27 ppmv, dry. Furthermore, it shows that the Km and Mixing path lines cross at around 85°F and will form more than 5 ppm of aerosol NH_4Cl. Thus, a visible plume would be predicted.



Conditions	° F	° C
Ambient Air Temperature	14	-10
Reheating Temperature	380	193
Stack Temperature	350	177
HCl Concentration (ppmv, dry)	27	
NH_3 Concentration (ppmv, dry)	27	

Figure 5

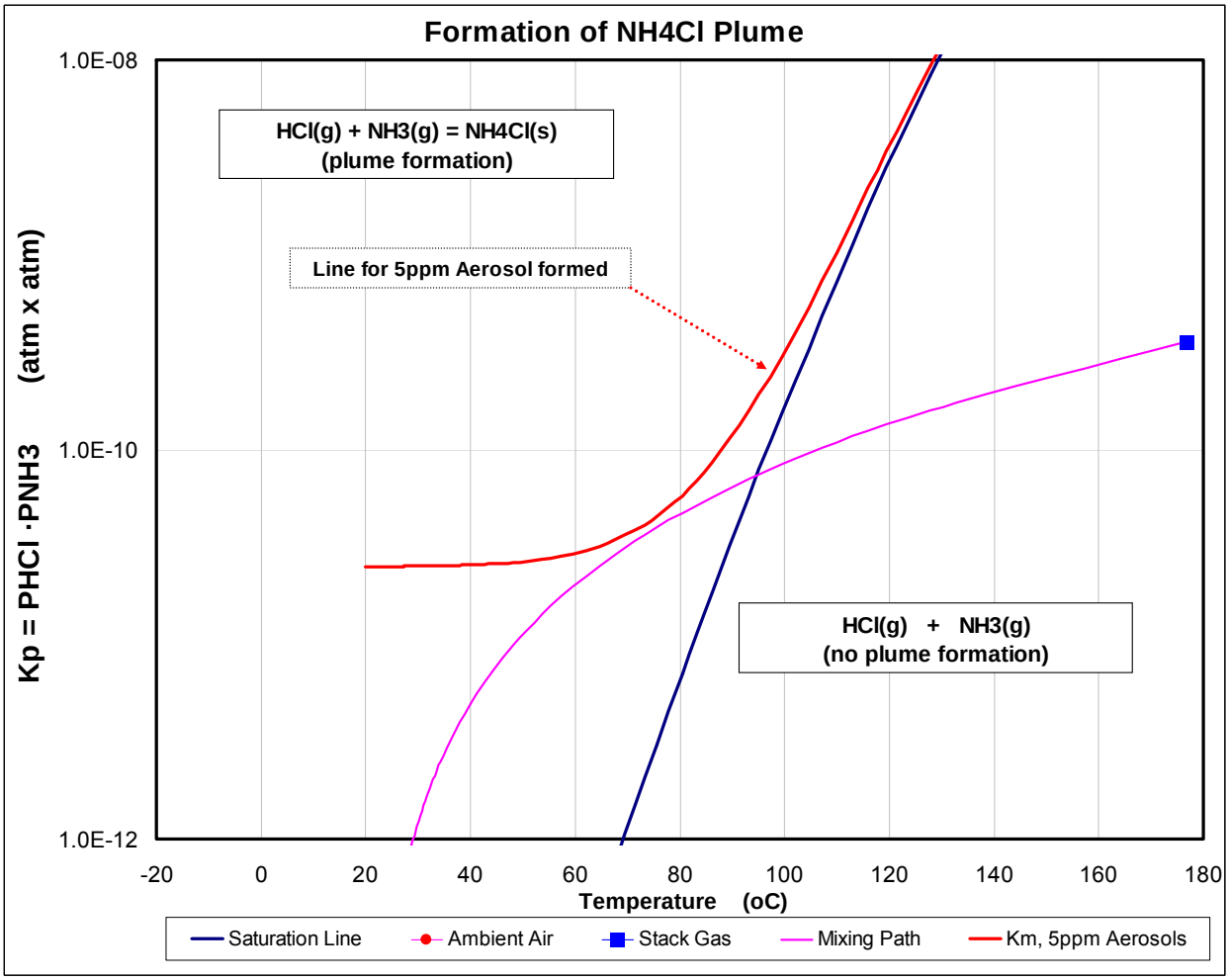
Figure 6 has the same ambient and stack temperatures as well as pollutant concentrations as Scenario 1, but provides more detail (zoomed in view) where the Km and Mixing Path lines cross.



Conditions	°F	°C
Ambient Air Temperature	14	-10
Reheating Temperature	380	193
Stack Temperature	350	177
HCl Concentration (ppmv, dry)	27	
NH_3 Concentration (ppmv, dry)	27	

Figure 6

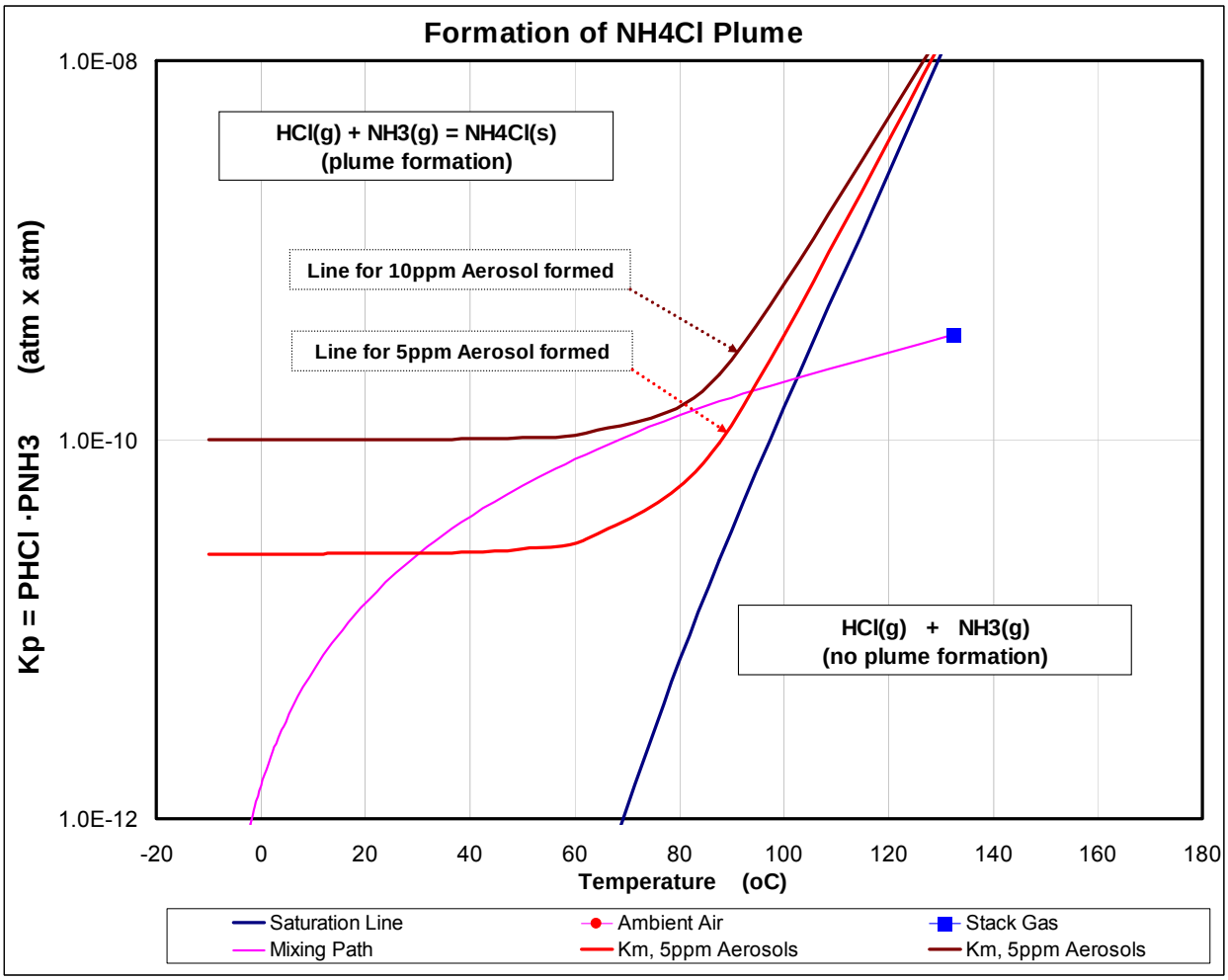
Scenario 2 (Figure 7) represents the situation in Figures 5 & 6 (380 F reheating and 350 F stack temperature) but at a typical spring/summer temperature of 68°F. At these conditions, the Mixing Path barely misses the line representing 5 ppm aerosol NH_4Cl formation. Thus, a visible plume formation is not anticipated.



Conditions	°F	°C
Ambient Air Temperature	68	20
Reheating Temperature	380	193
Stack Temperature	350	177
HCl Concentration (ppmv, dry)	27	
NH_3 Concentration (ppmv, dry)	27	

Figure 7

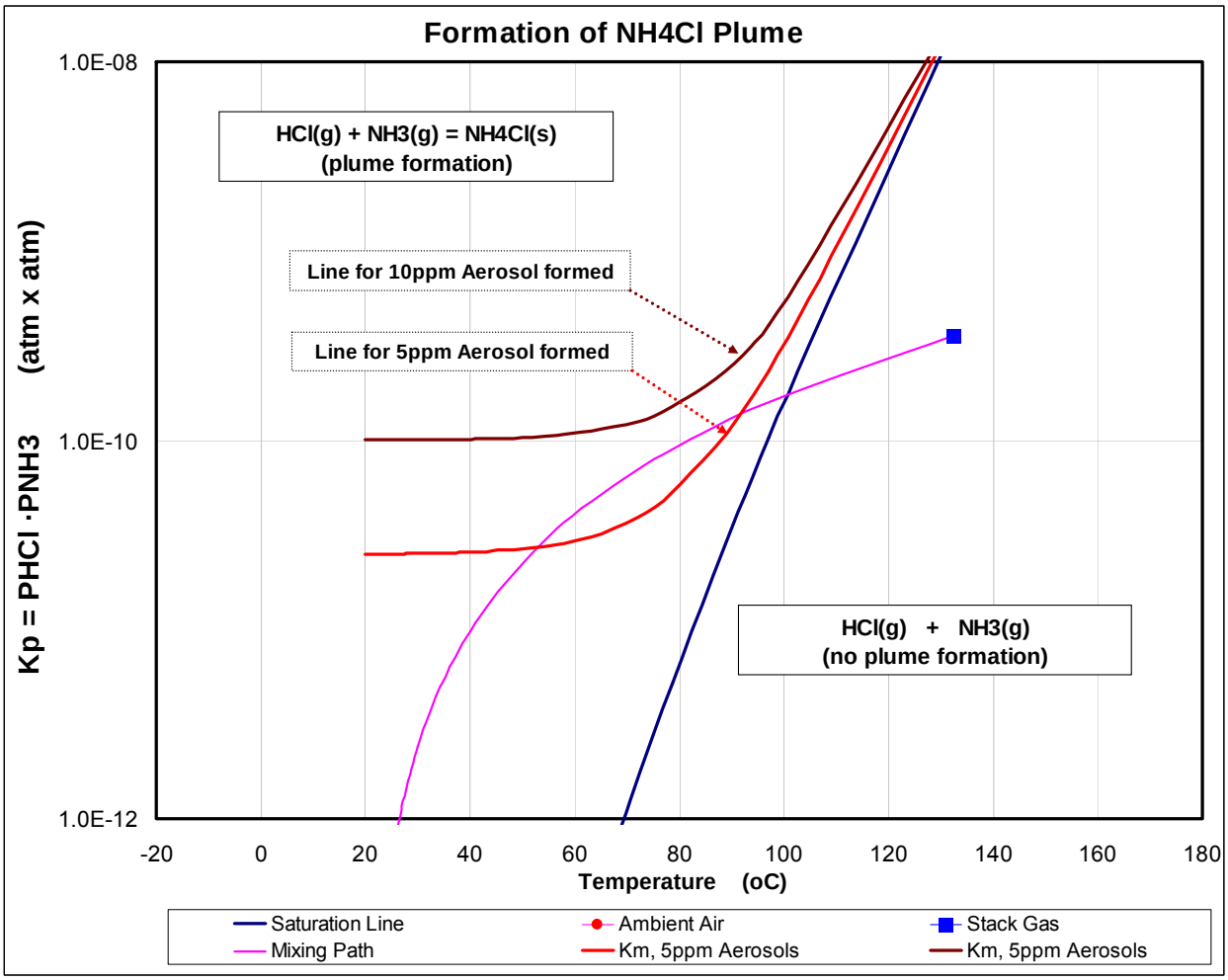
Scenario 3 (Figure 8) provides a reheating gas temperature of 300 °F corresponding to a stack temperature of 270 °F and the maximum 5 year pollutant concentration of 27 ppmv, dry at winter ambient conditions. At this stack temperature, the Mixing Path crosses the 5 ppm aerosol NH_4Cl formation line and nearly crosses a 10 ppm aerosol NH_4Cl line. This scenario has a very high risk of a visible plume problem with >20% opacity.



Conditions	°F	°C
Ambient Air Temperature	14	-10
Reheating Temperature	300	149
Stack Temperature	270	132
HCl Concentration (ppmv, dry)	27	
NH_3 Concentration (ppmv, dry)	27	

Figure 8

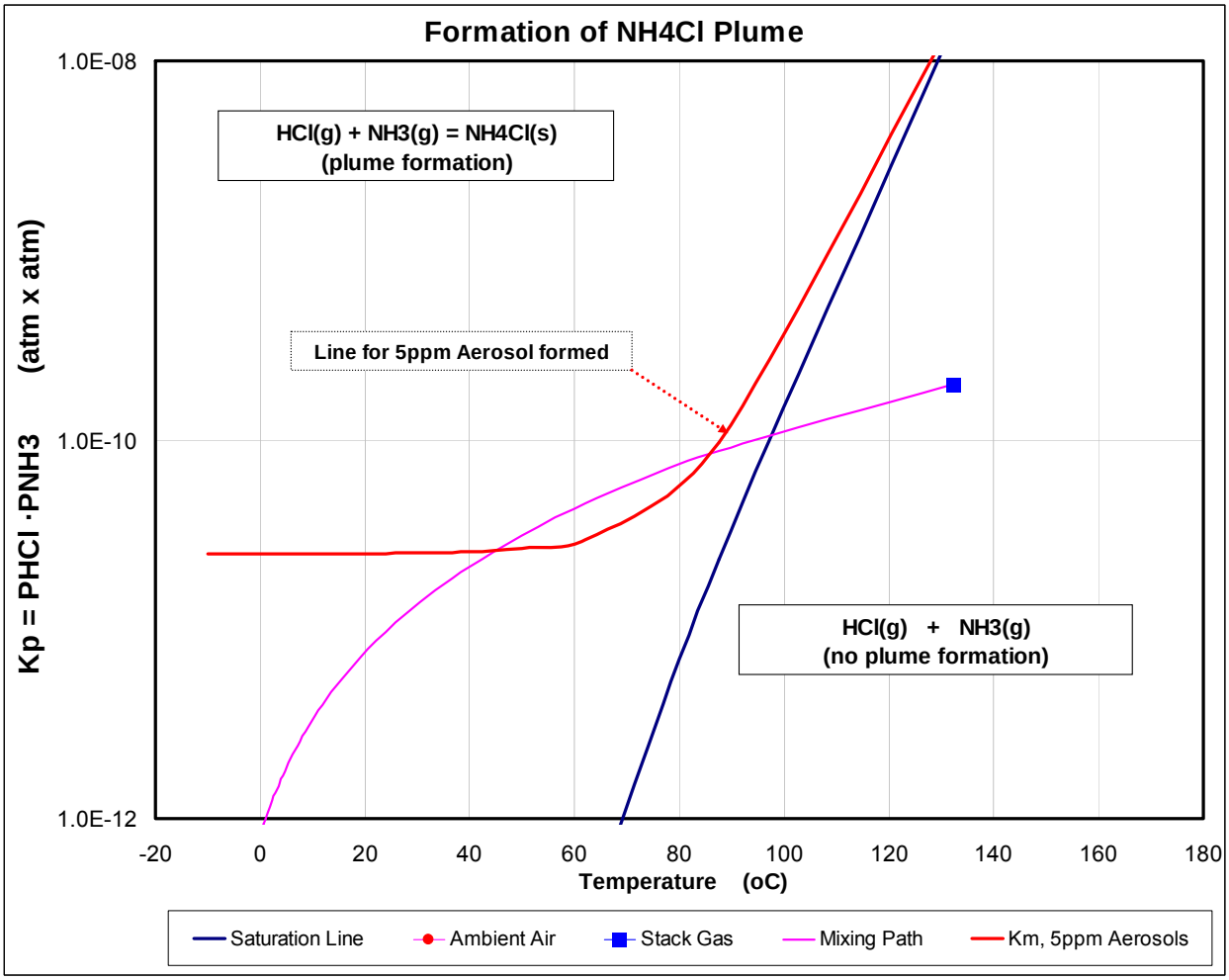
Scenario 4 (Figure 9) provides a reheating gas temperature of 300 °F corresponding to a stack temperature of 270 °F and the maximum 5 year pollutant concentration of 27 ppmv, dry (same as Scenario 3) but at typical spring/summer ambient temperatures. At this stack temperature, the Mixing Path still crosses the 5 ppm aerosol NH_4Cl formation line. This scenario also has a high risk of a visible plume problem. However, it is not predicted to be as severe as the previous scenario.



Conditions	°F	°C
Ambient Air Temperature	68	20
Reheating Temperature	300	149
Stack Temperature	270	132
HCl Concentration (ppmv, dry)	27	
NH_3 Concentration (ppmv, dry)	27	

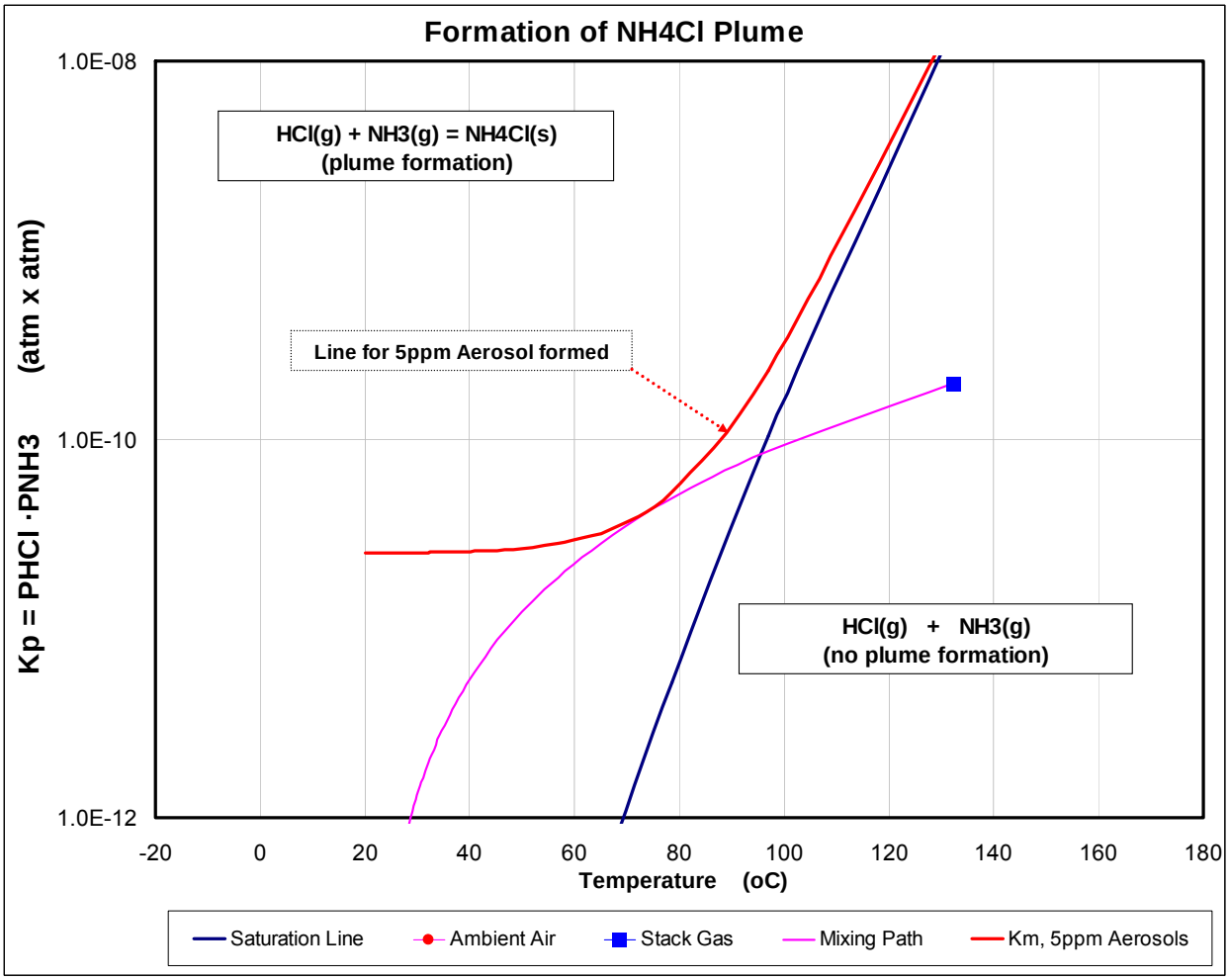
Figure 9

Scenarios 5 and 6 (Figure 10 and Figure 11). Under these temperatures, the average 5 year concentration of NH_3 (25 ppmv, dry) and HCl (16 ppmv, dry) is predicted to form more than 5 ppm of aerosol NH_4Cl at an average winter temperature (Figure 10) and close to 5 ppm at an average summer (Figure 11) ambient temperature.



Conditions	°F	°C
Ambient Air Temperature	14	-10
Reheating Temperature	300	149
Stack Temperature	270	132
HCl Concentration (ppmv, dry)	16	
NH_3 Concentration (ppmv, dry)	25	

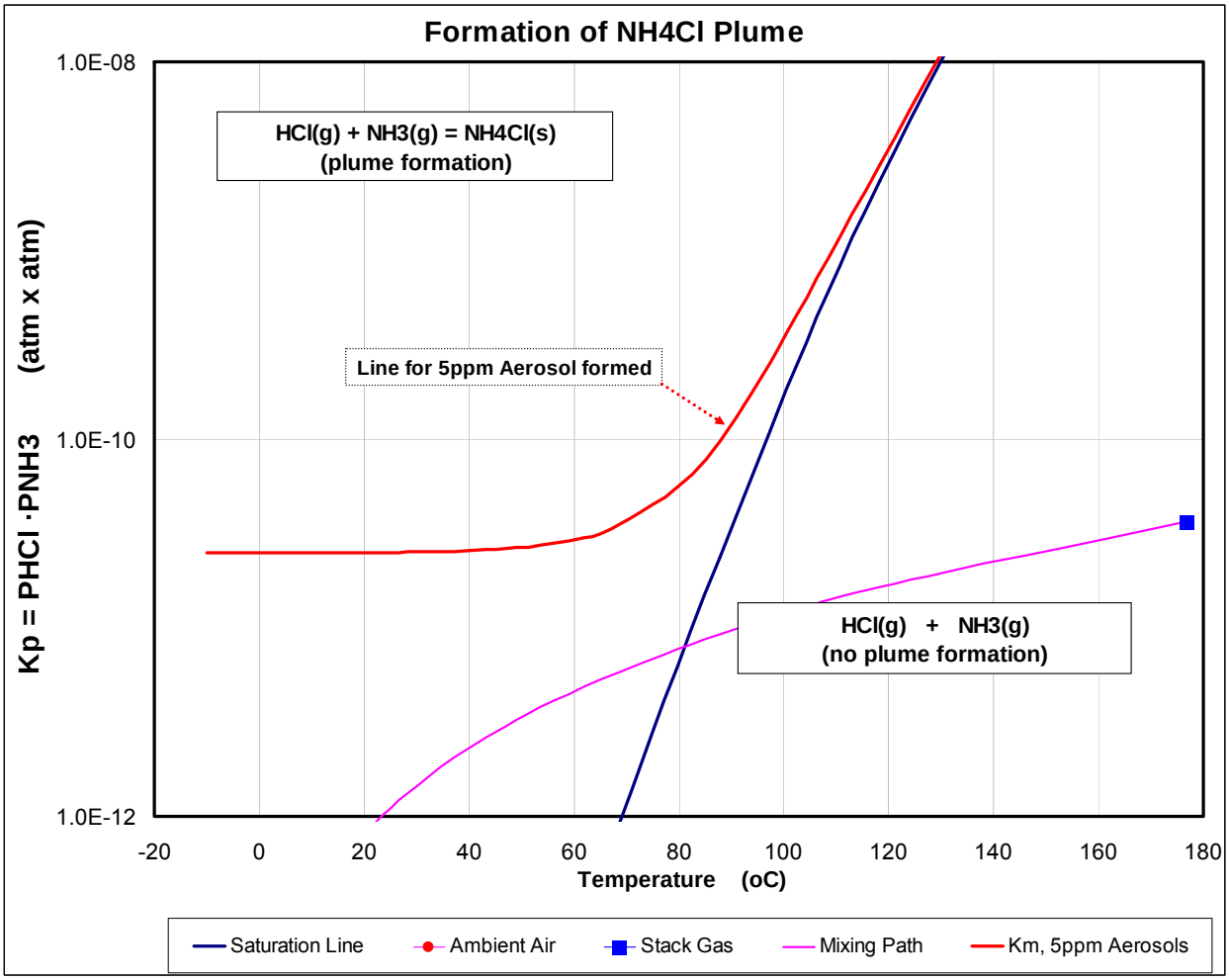
Figure 10



Conditions	°F	°C
Ambient Air Temperature	68	20
Reheating Temperature	300	149
Stack Temperature	270	132
HCl Concentration (ppmv, dry)	16	
NH_3 Concentration (ppmv, dry)	25	

Figure 11

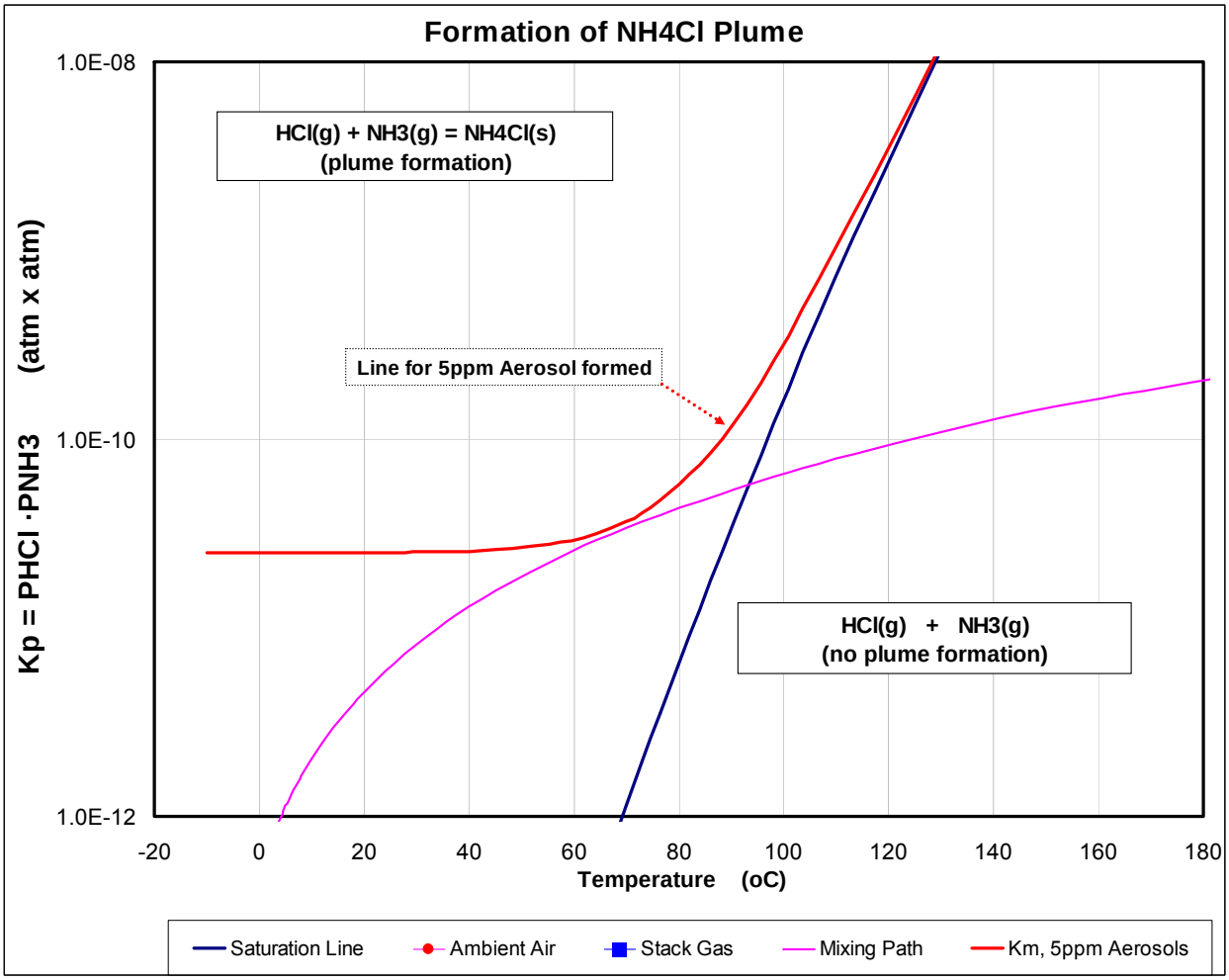
Scenario 7 (Figure 12) represents the actual 2007 condition of the Clarksville plant at a typical winter temperature. It is apparent that the Mixing Path line and Km are not crossing since the total HCl concentration is only 3 ppm. Note that the HCl concentration in 2007 was the lowest of the 5 years and could vary to more than 30 ppm as found in 2003.



Conditions	°F	°C
Ambient Air Temperature	14	-10
Reheating Temperature	380	193
Stack Temperature	350	177
HCl Concentration (ppmv, dry)	3	
NH_3 Concentration (ppmv, dry)	25	

Figure 12

Scenario 8 (Figure 13) shows the actual 2004 conditions of the plant at a typical winter ambient condition. Although the HCl and NH_3 concentrations are relatively high, the high stack temperature (480 deg F) allows for dilution and the Mixing Path line does not cross the Km line and therefore less than a 5 ppm aerosol NH_4Cl concentration is predicted.



Conditions	°F	°C
Ambient Air Temperature	14	-10
Reheating Temperature	480	249
Stack Temperature	450	232
HCl Concentration (ppmv, dry)	27	
NH_3 Concentration (ppmv, dry)	27	

Figure 13

Conclusion

In conclusion, the stack temperature needed to prevent a visible plume from occurring is highly dependent on the ambient temperature, the concentrations of HCl and NH_3 in the gas stream, as well as other factors. Due to the normal variability in HCl and NH_3 concentrations, it is virtually assured that the combination of higher HCl and NH_3 concentrations and lowering the stack gas temperature below current levels (380 deg F at the exit of ESP and 350 deg F at stack) would lead to a visible plume condition.

Supplement A: Some Examples of plume problems in cement Industry

The first regulatory action concerning secondary plumes in the cement industry occurred in 1979 at Glens Falls Cement, Glens Falls, New York, USA. Plume studies were conducted by EPA and stack test contractors by sampling the plume using a tethered balloon.

The secondary plume was observed to have an average opacity of ~85% while the in-stack opacity was only 10%. The tests revealed that the particulate matter recovered from the plume was mainly crystals of ammonium sulphate. The tests indicated that the primary components of the stack effluent were $(NH4)_2SO4$ (4.5 ppm), SO_2 (200 ppm), NH_3 (170 ppm), moisture (20%). The ammonium sulphate in the stack gas was responsible for the 10% in-stack opacity.

The secondary plume was also observed at Lehigh Cement in Leeds, Alabama, USA. Testing conducted in 1981 indicated that the major species responsible for the plume was ammonium chloride, NH4Cl.

Similar tests were conducted in 1987 at Kaiser Cement in Permamenti, California, USA. The results revealed that NH4Cl was also responsible for the visible secondary plume. The secondary plume tests conducted in 1987 at Southwestern Portland Cement in Victorville, California, USA, also revealed that NH4Cl was responsible for the visible secondary plume.

In 1986, EPA conducted a source and process sampling program at the South Dakota Cement Company, Rapid City, South Dakota, USA. The samples collected from the secondary plume contain up to 67% NH4Cl. Further tests indicated that the NH3 exists mainly in the shale that accounts for about 20% of raw mix. The plant has a dry process with a 4-stage preheater, vertical roller mill for raw grinding and a main baghouse for dedusting. A severe ammonia recirculation was observed, with an average NH3 content in shale being 6.2 ppm while up to 159 ppm NH_3 was found in the baghouse dust. It was also observed that the NH3 content in the baghouse dust was reduced substantially when gas temperature increased from 170 deg C (compound operation) to 250 deg C (direction operation).

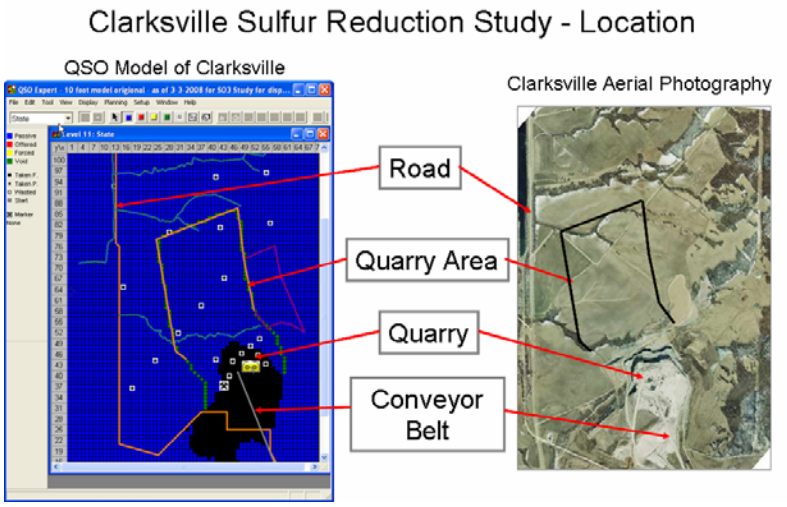
The secondary plumes in cement plants are not limited to the USA. They have also been reported by a Mexican cement company which determined through plant measurements that NH4Cl was responsible for the visible plume.

Other examples include the Lone Star Industries' Cape Girardeau Cement Plant, MO, USA and the Inland Cement, Edmonton, AB, Canada. Both plants experienced secondary plumes due to formation of ammonium sulphate.

APPENDIX C. SELECTIVE MINING – QUARRY SCHEDULING OPTIMIZATION DISCUSSION

Appendix C. Selective Mining – Quarry Scheduling Optimization Discussion

Holcim (US) Inc. evaluated the Clarksville Quarry Scheduling Optimization (QSO) model for sulfur emissions.

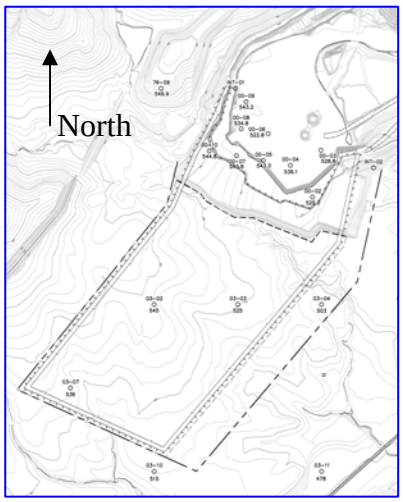


The model is based on statistical and spatial analysis of data obtained through drill core sub sampling. Validation of relevant data is insured through the analysis of varagrams and histograms. This validation insures that correlation between samples is relevant.

The Clarksville QSO Model was created specifically for predicting relevant mineralogical parameters related to clinker production. Major oxides (Ca, Mg, Si, and Fe) are the primary focus of this predictive model. The sampling protocol and data analysis required for major oxide components was never intended to be adequate for the accurate prediction of minor components, such as sulfur and sulfur compounds.

When placed under scrutiny, existing data was found to be inadequate for accurate prediction of S content in the potentially quarried shale. Spatial relationships between core samples were found to be inappropriate for the sensitivity needed to make accurate predictions. The reason for this is the geologic nature of the Maquiketa Shale and Kimmswick Limestone, of which the primary sulfur mineral is pyrite (FeS).

One of the most important chemical processes in organic-rich marine sediments, such as Maquiketa shale, is decomposition of organic matter (OM)in bacterial sulphate reduction. Bacterial sulphate reduction produces bisulphide. Bisulphite can be partially oxidized or can react with OM and reactive metal species. All these reactions may be bacterially mediated. The reaction of reduced sulfur with reactive dissolved iron and iron minerals, if available, results in the formation of iron sulphides. The most common iron sulphide in pyrite.



The amount of pyrite formation in marine sediments is largely determined by the availability of sulphate, reactive iron and reactive OM during the formation of

the sediments. The locations of the reactive iron and sulphate are a random occurrence, usually along planes of weakness or channels of solubility during rock forming (induration). The pyrite is formed as nodules or clusters of mineralization and is not evenly distributed spatially throughout the shale and limestone.

Therefore the chance of intercepting a pyrite cluster of mineralization by core drilling is known as a ‘nugget’ effect. Intercepting a pyrite cluster will give artificially high sulfur values in the model and, conversely, not intercepting pyrite mineralization can give low values.

In the planned mining area only 5 core holes were drilled (DH-2, DH-3, DH-4 and DH-7). While the spacing of the drill holes are adequate for predicting major oxides, they are too far apart and too few to accurately predict clustered mineralogy such as pyrite.

APPENDIX D. BART CONTROL COST TABLES

Table D-1. Wet Limestone Scrubber Control Cost Analysis Based on Projected Actual Emissions and 80% Control.

Direct Costs			
Purchased Equipment Costs			
	Wet Scrubber Unit including Limestone Prep System, inflated to 2012 dollars		$17,317,574
	Instrumentation (10% of EC)		$1,731,757
	Freight (5% of EC)		$865,879
		Subtotal, Purchased Equipment Cost (PEC)	$19,915,210
Direct Installation Costs			
	Foundation (6% of PEC)		$1,194,913
	Supports (6% of PEC)		$1,194,913
	Handling and Erection (40% of PEC)		$7,966,084
	Electrical (1% of PEC)		$199,152
	Piping (30% of PEC)		$5,974,563
	Extending gas line 1/2 mile to plant		$500,000
	Insulation for Ductwork (1% of PEC)		$199,152
	Painting (1% of PEC)		$199,152
		Subtotal, Direct Installation Cost	$17,427,929
Site Preparation			N/A
Buildings			N/A
		Total Direct Cost	**$37,343,139**
Indirect Costs			
	Engineering (10% of PEC)		$1,991,521
	Construction and Field Expense (10% of PEC)		$1,991,521
	Contractor Fees (10% of PEC)		$1,991,521
	Start-up (1% of PEC)		$199,152
	Performance Test (1% of PEC)		$199,152
	Contingencies (3% of PEC)		$597,456
		Total Indirect Cost	**$6,970,324**
	Total Capital Investment (TCI)		**$44,313,462**
Direct Annual Costs			
Hours per Year	(365 days per year, 24 hours per day), 90% Uptime		7,884
Operating Labor			
	Operator 2 x 3,573 hours/year, $50/hr)		$357,300
	Supervisor (15% of operator)		$53,595
		Subtotal, Operating Labor	$410,895
Maintenance			
	Labor (2 x 820 hours/year, $50/hr)		$82,000
	Material (5% of Total Direct Cost)	$	1,867,157
		Subtotal, Maintenance	$1,949,157
Utilities			
	Electricity		
	Pump (kW)		2,342
	Cost ($/kW-hr)		$0.0410
		Subtotal, Electricity	$757,054
	Limestone for slurry		
	Amount Required (ton/yr)		13,961
	Cost ($/ton)		$3.00
		Subtotal, Limestone	$41,883
	Water		
	Amount Required (gpm)		122.0
	Cost ($/1000 gallons)		$1.00
		Subtotal, Water	$64,128
	Sludge Disposal		
	Amount Generated (tpy)		57,943
	Disposal Fee ($/ton)		$36.00
	Monthly Rent for Trailer @ $120/month		$1,440
	Cost for Box Transportation @ $220/load (assume 17 tons/trailer)		$749,853
		Subtotal, Sludge	$2,837,247
		Subtotal, Utilities	$3,700,312
	Natural Gas Reheat (assuming a 210 deg F temp drop and reheat)		
	Gas Required (MMCF/yr)		1,020,986
	Cost ($/MMBTU)		$10.06
		Subtotal, Natural Gas	$10,271,123
		Total Direct Annual Costs	**$16,331,486**
Indirect Annual Costs			
	Overhead (60% of sum of operating, supervisor, maintenance labor & materials)		$1,416,031
	Administrative (2% TCI)		$886,269
	Property Tax (1% TCI)		$443,135
	Insurance (1% TCI)		$443,135
Capital Recovery	(15 year life, 7 percent interest)		$4,865,380
		Total Indirect Annual Cost	**$8,053,950**
Conclusion			
	Total Annualized Cost		**$24,385,436**
	Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)		**11,481**
	Pollutant Removed (tons SO_2/yr) - 80%, 95% uptime		**8,726**
	Pollutant Generated - NOx tons/yr		**97**
	Net Pollutant Removed - tons/yr		**8,629**
	Cost Per Ton of Pollutant Removed		**$2,826**

Table D-2. Wet Limestone Scrubber Control Cost Analysis Based on Projected Actual Emissions and 95% Control.

Direct Costs		
Purchased Equipment Costs		
	Wet Scrubber Unit including Limestone Prep System, inflated to 2012 dollars	$17,317,574
	Instrumentation (10% of EC)	$1,731,757
	Freight (5% of EC)	$865,879
	Subtotal, Purchased Equipment Cost (PEC)	$19,915,210
Direct Installation Costs		
	Foundation (6% of PEC)	$1,194,913
	Supports (6% of PEC)	$1,194,913
	Handling and Erection (40% of PEC)	$7,966,084
	Electrical (1% of PEC)	$199,152
	Piping (30% of PEC)	$5,974,563
	Extending gas line 1/2 mile to plant	$500,000
	Insulation for Ductwork (1% of PEC)	$199,152
	Painting (1% of PEC)	$199,152
	Subtotal, Direct Installation Cost	$17,427,929
Site Preparation		N/A
Buildings		N/A
	Total Direct Cost	**$37,343,139**
Indirect Costs		
	Engineering (10% of PEC)	$1,991,521
	Construction and Field Expense (10% of PEC)	$1,991,521
	Contractor Fees (10% of PEC)	$1,991,521
	Start-up (1% of PEC)	$199,152
	Performance Test (1% of PEC)	$199,152
	Contingencies (3% of PEC)	$597,456
	Total Indirect Cost	**$6,970,324**
	Total Capital Investment (TCI)	**$44,313,462**
Direct Annual Costs		
Hours per Year	(365 days per year, 24 hours per day), 90% Uptime	7,884
Operating Labor		
	Operator 2 x 3,573 hours/year, $50/hr)	$357,300
	Supervisor (15% of operator)	$53,595
	Subtotal, Operating Labor	$410,895
Maintenance		
	Labor (2 x 820 hours/year, $50/hr)	$82,000
	Material (5% of Total Direct Cost)	$ 1,867,157
	Subtotal, Maintenance	$1,949,157
Utilities		
	Electricity	
	Pump (kW)	2,342
	Cost ($/kW-hr)	$0.0410
	Subtotal, Electricity	$757,054
	Limestone for slurry	
	Amount Required (ton/yr)	16,579
	Cost ($/ton)	$3.00
	Subtotal, Lime	$49,736
	Water	
	Amount Required (gpm)	122.0
	Cost ($/1000 gallons)	$1.00
	Subtotal, Water	$64,128
	Sludge Disposal	
	Amount Generated (tpy)	68,808
	Disposal Fee ($/ton)	$36.00
	Monthly Rent for Trailer @ $120/month	$1,440
	Cost for Box Transportation @ $220/load (assume 17 tons/trailer)	$890,450
	Subtotal, Sludge	$3,368,961
	Subtotal, Utilities	$4,239,878
	Natural Gas Reheat (assuming a 210 deg F temp drop and reheat)	
	Gas Required (MMCF/yr)	1,020,986
	Cost ($/MMBTU)	$10.06
	Subtotal, Natural Gas	$10,271,123
	Total Direct Annual Costs	**$16,871,053**
Indirect Annual Costs		
Overhead (60% of sum of operating, supervisor, maintenance labor & materials)		$1,416,031
Administrative (2% TCI)		$886,269
Property Tax (1% TCI)		$443,135
Insurance (1% TCI)		$443,135
Capital Recovery	(15 year life, 7 percent interest)	$4,865,380
	Total Indirect Annual Cost	**$8,053,950**
Conclusion		
	Total Annualized Cost	**$24,925,003**
	Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)	**11,481**
	Pollutant Removed (tons SO_2/yr) - 95%, 95% uptime	**10,362**
	Pollutant Generated - NOx tons/yr	**97**
	Net Pollutant Removed - tons/yr	**10,265**
	Cost Per Ton of Pollutant Removed	**$2,428**

Table D-3. Wet Limestone Scrubber Control Cost Analysis Based on PTE and 80% Control

Direct Costs			
Purchased Equipment Costs			
	Wet Scrubber Unit including Limestone Prep System, inflated to 2012 dollars		$17,317,574
	Instrumentation (10% of EC)		$1,731,757
	Freight (5% of EC)		$865,879
		Subtotal, Purchased Equipment Cost (PEC)	$19,915,210
Direct Installation Costs			
	Foundation (6% of PEC)		$1,194,913
	Supports (6% of PEC)		$1,194,913
	Handling and Erection (40% of PEC)		$7,966,084
	Electrical (1% of PEC)		$199,152
	Piping (30% of PEC)		$5,974,563
	Extending gas line 1/2 mile to plant		$500,000
	Insulation for Ductwork (1% of PEC)		$199,152
	Painting (1% of PEC)		$199,152
		Subtotal, Direct Installation Cost	$17,427,929
Site Preparation			N/A
Buildings			N/A
		Total Direct Cost	**$37,343,139**
Indirect Costs			
	Engineering (10% of PEC)		$1,991,521
	Construction and Field Expense (10% of PEC)		$1,991,521
	Contractor Fees (10% of PEC)		$1,991,521
	Start-up (1% of PEC)		$199,152
	Performance Test (1% of PEC)		$199,152
	Contingencies (3% of PEC)		$597,456
		Total Indirect Cost	**$6,970,324**
	Total Capital Investment (TCI)		**$44,313,462**
Direct Annual Costs			
Hours per Year	(365 days per year, 24 hours per day), 90% Uptime		7,884
Operating Labor			
	Operator 2 x 3,573 hours/year, $50/hr)		$357,300
	Supervisor (15% of operator)		$53,595
		Subtotal, Operating Labor	$410,895
Maintenance			
	Labor (2 x 820 hours/year, $50/hr)		$82,000
	Material (5% of Total Direct Cost)	$	1,867,157
		Subtotal, Maintenance	$1,949,157
Utilities			
	Electricity		
	Pump (kW)		2,342
	Cost ($/kW-hr)		$0.0410
		Subtotal, Electricity	$757,054
	Limestone for slurry		
	Amount Required (ton/yr)		16,170
	Cost ($/ton)		$3.00
		Subtotal, Lime	$48,511
	Water		
	Amount Required (gpm)		122.0
	Cost ($/1000 gallons)		$1.00
		Subtotal, Water	$64,128
	Sludge Disposal		
	Amount Generated (tpy)		67,113
	Disposal Fee ($/ton)		$36.00
	Monthly Rent for Trailer @ $120/month		$1,440
	Cost for Box Transportation @ $220/load (assume 17 tons/trailer)		$868,526
		Subtotal, Sludge	$3,286,046
		Subtotal, Utilities	$4,155,739
	Natural Gas Reheat (assuming a 210 deg F temp drop and reheat)		
	Gas Required (MMCF/yr)		1,020,986
	Cost ($/MMBTU)		$10.06
		Subtotal, Natural Gas	$10,271,123
		Total Direct Annual Costs	**$16,786,914**
Indirect Annual Costs			
Overhead (60% of sum of operating, supervisor, maintenance labor & materials)			$1,416,031
Administrative (2% TCI)			$886,269
Property Tax (1% TCI)			$443,135
Insurance (1% TCI)			$443,135
Capital Recovery	(15 year life, 7 percent interest)		$4,865,380
		Total Indirect Annual Cost	**$8,053,950**
Conclusion			
	Total Annualized Cost		**$24,840,863**
	Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr) - PTE		**13,298**
	Pollutant Removed (tons SO_2/yr) - 80%, 95% uptime		**10,106**
	Pollutant Generated - NOx tons/yr		**97**
	Net Pollutant Removed - tons/yr		**10,009**
	Cost Per Ton of Pollutant Removed		**$2,482**

Table D-4. Wet Limestone Scrubber Control Cost Analysis Based on PTE and 95% Control

Direct Costs			
Purchased Equipment Costs			
	Wet Scrubber Unit including Limestone Prep System, inflated to 2012 dollars		$17,317,574
	Instrumentation (10% of EC)		$1,731,757
	Freight (5% of EC)		$865,879
		Subtotal, Purchased Equipment Cost (PEC)	$19,915,210
Direct Installation Costs			
	Foundation (6% of PEC)		$1,194,913
	Supports (6% of PEC)		$1,194,913
	Handling and Erection (40% of PEC)		$7,966,084
	Electrical (1% of PEC)		$199,152
	Piping (30% of PEC)		$5,974,563
	Extending gas line 1/2 mile to plant		$500,000
	Insulation for Ductwork (1% of PEC)		$199,152
	Painting (1% of PEC)		$199,152
		Subtotal, Direct Installation Cost	$17,427,929
Site Preparation			N/A
Buildings			N/A
		Total Direct Cost	**$37,343,139**
Indirect Costs			
	Engineering (10% of PEC)		$1,991,521
	Construction and Field Expense (10% of PEC)		$1,991,521
	Contractor Fees (10% of PEC)		$1,991,521
	Start-up (1% of PEC)		$199,152
	Performance Test (1% of PEC)		$199,152
	Contingencies (3% of PEC)		$597,456
		Total Indirect Cost	**$6,970,324**
	Total Capital Investment (TCI)		**$44,313,462**
Direct Annual Costs			
Hours per Year	(365 days per year, 24 hours per day), 90% Uptime		7,884
Operating Labor			
	Operator 2 x 3,573 hours/year, $50/hr)		$357,300
	Supervisor (15% of operator)		$53,595
		Subtotal, Operating Labor	$410,895
Maintenance			
	Labor (2 x 820 hours/year, $50/hr)		$82,000
	Material (5% of Total Direct Cost)	$	1,867,157
		Subtotal, Maintenance	$1,949,157
Utilities			
	Electricity		
	Pump (kW)		2,342
	Cost ($/kW-hr)		$0.0410
		Subtotal, Electricity	$757,054
	Limestone for slurry		
	Amount Required (ton/yr)		19,202
	Cost ($/ton)		$3.00
		Subtotal, Lime	$57,607
	Water		
	Amount Required (gpm)		122.0
	Cost ($/1000 gallons)		$1.00
		Subtotal, Water	$64,128
	Sludge Disposal		
	Amount Generated (tpy)		79,697
	Disposal Fee ($/ton)		$36.00
	Monthly Rent for Trailer @ $120/month		$1,440
	Cost for Box Transportation @ $220/load (assume 17 tons/trailer)		$1,031,374
		Subtotal, Sludge	$3,901,910
		Subtotal, Utilities	$4,780,698
	Natural Gas Reheat (assuming a 210 deg F temp drop and reheat)		
	Gas Required (MMCF/yr)		1,020,986
	Cost ($/MMBTU)		$10.06
		Subtotal, Natural Gas	$10,271,123
		Total Direct Annual Costs	**$17,411,873**
Indirect Annual Costs			
Overhead (60% of sum of operating, supervisor, maintenance labor & materials)			$1,416,031
Administrative (2% TCI)			$886,269
Property Tax (1% TCI)			$443,135
Insurance (1% TCI)			$443,135
Capital Recovery	(15 year life, 7 percent interest)		$4,865,380
		Total Indirect Annual Cost	**$8,053,950**
Conclusion			
	Total Annualized Cost		**$25,465,823**
	Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr) - PTE		**13,298**
	Pollutant Removed (tons SO_2/yr) - 95%, 95% uptime		**12,001**
	Pollutant Generated - NOx tons/yr		**97**
	Net Pollutant Removed - tons/yr		**11,904**
	Cost Per Ton of Pollutant Removed		**$2,139**

Table D-5. Fuel Substitution Control Cost Analysis Based on Projected Actual Emissions and 23% Control .

Direct Costs

Purchased Equipment Costs		
	New Coal Mill I.D. Fan and associated equipment	$2,000,000
	Instrumentation (10% of EC)	$200,000
	Freight (5% of EC)	$100,000
	Subtotal, Purchased Equipment Cost (PEC)	$2,300,000
Direct Installation Costs		
	Foundation (6% of PEC)	$138,000
	Supports (6% of PEC)	$138,000
	Handling and Erection (40% of PEC)	$920,000
	Electrical (1% of PEC)	$23,000
	Piping (30% of PEC)	$690,000
	Insulation for Ductwork (1% of PEC)	$1,000
	Painting (1% of PEC)	$23,000
	Subtotal, Direct Installation Cost	$1,933,000
Site Preparation		N/A
Buildings		N/A
	Total Direct Cost	**$4,233,000**

Indirect Costs

Engineering (10% of PEC)	$230,000
Construction and Field Expense (10% of PEC)	$230,000
Contractor Fees (10% of PEC)	$230,000
Start-up (1% of PEC)	$23,000
Performance Test (1% of PEC)	$23,000
Contingencies (3% of PEC)	$69,000
Total Indirect Cost	**$805,000**
Total Capital Investment (TCI)	**$5,038,000**

Direct Annual Costs

Increased Fuel Cost (calculated by scaling 2007 annual average fuel usage by the ratio of maximum annual clinker production (1,215,708 tons) to 2007 actual clinker production (1,035,283 tons)

Increased Fuel Cost (calculated by scaling 2007 annual average fuel usage to maximum actual production levels)		
	Reduction in coke usage (metric ton/yr)	188,959
	Heat Value (Gj / Mt)	32.510
	Heat (Gj / yr)	6,143,045
	Cost ($/Gj)	$1.74
	Subtotal, reduction in coke cost	-$10,688,898
	Reduction in coal usage (metric ton/yr)	11,076
	Heat Value (Gj / Mt)	22.177
	Heat (Gj / yr)	245,627
	Cost ($/Gj)	$2.41
	Subtotal, reduction in coal cost	-$591,962
	Increase in low sulfur coal usage - Amount Required (metric ton/yr)	198,736
	Cost ($/Mt)	$72.76
	Subtotal, increase in Low Sulfur Coal cost	$14,459,211
	Total Direct Annual Cost (increase)	**$3,178,351**

Indirect Annual Costs

Administrative (2% TCI)		$100,760
Property Tax (1% TCI)		$50,380
Insurance (1% TCI)		$50,380
Capital Recovery	(15 year life, 7 percent interest)	$553,145
	Total Indirect Annual Cost	**$754,665**

Conclusion

Total Annualized Cost	**$3,933,016**
Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)	**11,481**
Pollutant Removed (tons SO_2/yr) - 23%	**2,641**
Cost Per Ton of Pollutant Removed	**$1,489**

Table D-6. Fuel Substitution Control Cost Analysis Based on Projected Actual Emissions and 40% Control .

Direct Costs

Purchased Equipment Costs		
	New Coal Mill and associated equipment	$5,374,302
	Instrumentation (10% of EC)	$537,430
	Freight (5% of EC)	$268,715
	Subtotal, Purchased Equipment Cost (PEC)	$6,180,447
Direct Installation Costs		
	Foundation (6% of PEC)	$370,827
	Supports (6% of PEC)	$370,827
	Handling and Erection (40% of PEC)	$2,472,179
	Electrical (1% of PEC)	$61,804
	Piping (30% of PEC)	$1,854,134
	Insulation for Ductwork (1% of PEC)	$2,687
	Painting (1% of PEC)	$61,804
	Subtotal, Direct Installation Cost	$5,194,263
Site Preparation		N/A
Buildings		N/A
	Total Direct Cost	**$11,374,710**

Indirect Costs

Engineering (10% of PEC)	$618,045
Construction and Field Expense (10% of PEC)	$618,045
Contractor Fees (10% of PEC)	$618,045
Start-up (1% of PEC)	$61,804
Performance Test (1% of PEC)	$61,804
Contingencies (3% of PEC)	$185,413
Total Indirect Cost	**$2,163,157**
Total Capital Investment (TCI)	**$13,537,867**

Direct Annual Costs

Increased Fuel Cost (calculated by scaling 2007 annual average fuel usage by the ratio of maximum annual clinker production (1,215,708 tons) to 2007 actual clinker production (1,035,283 tons)

Reduction in coke usage (metric ton/yr)	188,959
Heat Value (Gj / Mt)	32.510
Heat (Gj / yr)	6,143,045
Cost ($/Gj)	$1.74
Subtotal, reduction in coke cost	-$10,688,898
Reduction in coal usage (metric ton/yr)	11,076
Heat Value (Gj / Mt)	22.177
Heat (Gj / yr)	245,627
Cost ($/Gj)	$2.41
Subtotal, reduction in coal cost	-$591,962
Increase in low sulfur coal usage - Amount Required (metric ton/yr)	244,891
Heat Value (Gj / Mt)	26.266
Heat (Gj / yr)	6,432,296
Cost ($/Gj)	$5.67
Subtotal, increase in Low Sulfur Coal cost	$36,471,116
Total Direct Annual Cost (increase)	**$25,190,256**

Indirect Annual Costs

Administrative (2% TCI)		$270,757
Property Tax (1% TCI)		$135,379
Insurance (1% TCI)		$135,379
Capital Recovery	(15 year life, 7 percent interest)	$1,486,385
	Total Indirect Annual Cost	**$2,027,900**

Conclusion

Total Annualized Cost	**$27,218,156**
Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)	**11,481**
Pollutant Removed (tons SO_2/yr) - 40%	**4,592**
Cost Per Ton of Pollutant Removed	**$5,927**

Table D-7. Fuel Substitution Control Cost Analysis Based on Projected Actual Emissions and 50% Control .

Direct Costs

Purchased Equipment Costs		
	New Coal Mill and associated equipment	$5,374,302
	Instrumentation (10% of EC)	$537,430
	Freight (5% of EC)	$268,715
	Subtotal, Purchased Equipment Cost (PEC)	$6,180,447
Direct Installation Costs		
	Foundation (6% of PEC)	$370,827
	Supports (6% of PEC)	$370,827
	Handling and Erection (40% of PEC)	$2,472,179
	Electrical (1% of PEC)	$61,804
	Piping (30% of PEC)	$1,854,134
	Insulation for Ductwork (1% of PEC)	$2,687
	Painting (1% of PEC)	$61,804
	Subtotal, Direct Installation Cost	$5,194,263
Site Preparation		N/A
Buildings		N/A
	Total Direct Cost	**$11,374,710**

Indirect Costs

Engineering (10% of PEC)	$618,045
Construction and Field Expense (10% of PEC)	$618,045
Contractor Fees (10% of PEC)	$618,045
Start-up (1% of PEC)	$61,804
Performance Test (1% of PEC)	$61,804
Contingencies (3% of PEC)	$185,413
Total Indirect Cost	**$2,163,157**
Total Capital Investment (TCI)	**$13,537,867**

Direct Annual Costs

Increased Fuel Cost (calculated by scaling 2007 annual average fuel usage by the ratio of maximum annual clinker production (1,215,708 tons) to 2007 actual clinker production (1,035,283 tons)

Increased Fuel Cost (calculated by scaling 2007 annual average fuel usage to maximum actual production levels)	
Reduction in coke usage (metric ton/yr)	188,959
Heat Value (Gj / Mt)	32.510
Heat (Gj / yr)	6,143,045
Cost ($/Gj)	$1.74
Subtotal, reduction in coke cost	-$10,688,898
Reduction in coal usage (metric ton/yr)	11,076
Heat Value (Gj / Mt)	22.177
Heat (Gj / yr)	245,627
Cost ($/Gj)	$2.41
Subtotal, reduction in coal cost	-$591,962
Increase in low sulfur coal usage - Amount Required (metric ton/yr)	244,891
Heat Value (Gj / Mt)	26.266
Heat (Gj / yr)	6,432,296
Cost ($/Gj)	$5.67
Subtotal, increase in Low Sulfur Coal cost	$36,471,116
Total Direct Annual Cost (increase)	**$25,190,256**

Indirect Annual Costs

Administrative (2% TCI)		$270,757
Property Tax (1% TCI)		$135,379
Insurance (1% TCI)		$135,379
Capital Recovery	(15 year life, 7 percent interest)	$1,486,385
	Total Indirect Annual Cost	**$2,027,900**

Conclusion

Total Annualized Cost	**$27,218,156**
Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)	**11,481**
Pollutant Removed (tons SO_2/yr) - 50%	**5,741**
Cost Per Ton of Pollutant Removed	**$4,741**

Table D-8. Fuel Substitution Control Cost Analysis Based on PTE and 23% Control.

Direct Costs

Purchased Equipment Costs		
	New Coal Mill I.D. Fan and associated equipment	$2,000,000
	Instrumentation (10% of EC)	$200,000
	Freight (5% of EC)	$100,000
	Subtotal, Purchased Equipment Cost (PEC)	$2,300,000
Direct Installation Costs		
	Foundation (6% of PEC)	$138,000
	Supports (6% of PEC)	$138,000
	Handling and Erection (40% of PEC)	$920,000
	Electrical (1% of PEC)	$23,000
	Piping (30% of PEC)	$690,000
	Insulation for Ductwork (1% of PEC)	$1,000
	Painting (1% of PEC)	$23,000
	Subtotal, Direct Installation Cost	$1,933,000
Site Preparation		N/A
Buildings		N/A
	Total Direct Cost	**$4,233,000**

Indirect Costs

Engineering (10% of PEC)	$230,000
Construction and Field Expense (10% of PEC)	$230,000
Contractor Fees (10% of PEC)	$230,000
Start-up (1% of PEC)	$23,000
Performance Test (1% of PEC)	$23,000
Contingencies (3% of PEC)	$69,000
Total Indirect Cost	**$805,000**
Total Capital Investment (TCI)	**$5,038,000**

Direct Annual Costs

Increased Fuel Cost (calculated by scaling 2007 annual average fuel usage by the ratio of maximum annual clinker production (1,215,708 tons) to 2007 actual clinker production (1,035,283 tons)

Increased Fuel Cost (calculated by scaling 2007 annual average fuel usage to maximum actual production levels)	
Reduction in coke usage (metric ton/yr)	188,959
Heat Value (Gj / Mt)	32.510
Heat (Gj / yr)	6,143,045
Cost ($/Gj)	$1.74
Subtotal, reduction in coke cost	-$10,688,898
Reduction in coal usage (metric ton/yr)	11,076
Heat Value (Gj / Mt)	22.177
Heat (Gj / yr)	245,627
Cost ($/Gj)	$2.41
Subtotal, reduction in coal cost	-$591,962
Increase in low sulfur coal usage - Amount Required (metric ton/yr)	198,736
Cost ($/Mt)	$72.76
Subtotal, increase in Low Sulfur Coal cost	$14,459,211
Total Direct Annual Cost (increase)	**$3,178,351**

Indirect Annual Costs

Administrative (2% TCI)		$100,760
Property Tax (1% TCI)		$50,380
Insurance (1% TCI)		$50,380
Capital Recovery	(15 year life, 7 percent interest)	$553,145
	Total Indirect Annual Cost	**$754,665**

Conclusion

Total Annualized Cost	**$3,933,016**
Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)	**13,298**
Pollutant Removed (tons SO_2/yr) - 23%	**3,059**
Cost Per Ton of Pollutant Removed	**$1,286**

Table D-9. Fuel Substitution Control Cost Analysis Based on PTE and 40% Control.

Direct Costs

Purchased Equipment Costs		
	New Coal Mill and associated equipment	$5,374,302
	Instrumentation (10% of EC)	$537,430
	Freight (5% of EC)	$268,715
	Subtotal, Purchased Equipment Cost (PEC)	$6,180,447
Direct Installation Costs		
	Foundation (6% of PEC)	$370,827
	Supports (6% of PEC)	$370,827
	Handling and Erection (40% of PEC)	$2,472,179
	Electrical (1% of PEC)	$61,804
	Piping (30% of PEC)	$1,854,134
	Insulation for Ductwork (1% of PEC)	$2,687
	Painting (1% of PEC)	$61,804
	Subtotal, Direct Installation Cost	$5,194,263
Site Preparation		N/A
Buildings		N/A
	Total Direct Cost	**$11,374,710**

Indirect Costs

Engineering (10% of PEC)	$618,045
Construction and Field Expense (10% of PEC)	$618,045
Contractor Fees (10% of PEC)	$618,045
Start-up (1% of PEC)	$61,804
Performance Test (1% of PEC)	$61,804
Contingencies (3% of PEC)	$185,413
Total Indirect Cost	**$2,163,157**
Total Capital Investment (TCI)	**$13,537,867**

Direct Annual Costs

Increased Fuel Cost (calculated by scaling 2007 annual average fuel usage by the ratio of maximum annual clinker production (1,215,708 tons) to 2007 actual clinker production (1,035,283 tons)

Increased Fuel Cost (calculated by scaling 2007 annual average fuel usage to maximum actual production levels)	
Reduction in coke usage (metric ton/yr)	188,959
Heat Value (Gj / Mt)	32.510
Heat (Gj / yr)	6,143,045
Cost ($/Gj)	$1.74
Subtotal, reduction in coke cost	-$10,688,898
Reduction in coal usage (metric ton/yr)	11,076
Heat Value (Gj / Mt)	22.177
Heat (Gj / yr)	245,627
Cost ($/Gj)	$2.41
Subtotal, reduction in coal cost	-$591,962
Increase in low sulfur coal usage - Amount Required (metric ton/yr)	244,891
Heat Value (Gj / Mt)	26.266
Heat (Gj / yr)	6,432,296
Cost ($/Gj)	$5.67
Subtotal, increase in Low Sulfur Coal cost	$36,471,116
Total Direct Annual Cost (increase)	**$25,190,256**

Indirect Annual Costs

Administrative (2% TCI)		$270,757
Property Tax (1% TCI)		$135,379
Insurance (1% TCI)		$135,379
Capital Recovery	(15 year life, 7 percent interest)	$1,486,385
	Total Indirect Annual Cost	**$2,027,900**

Conclusion

Total Annualized Cost	**$27,218,156**
Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)	**13,298**
Pollutant Removed (tons SO_2/yr) - 40%	**5,319**
Cost Per Ton of Pollutant Removed	**$5,117**

Table D-10. Fuel Substitution Control Cost Analysis Based on PTE and 50% Control.

Direct Costs

Purchased Equipment Costs		
	New Coal Mill and associated equipment	$5,374,302
	Instrumentation (10% of EC)	$537,430
	Freight (5% of EC)	$268,715
	Subtotal, Purchased Equipment Cost (PEC)	$6,180,447
Direct Installation Costs		
	Foundation (6% of PEC)	$370,827
	Supports (6% of PEC)	$370,827
	Handling and Erection (40% of PEC)	$2,472,179
	Electrical (1% of PEC)	$61,804
	Piping (30% of PEC)	$1,854,134
	Insulation for Ductwork (1% of PEC)	$2,687
	Painting (1% of PEC)	$61,804
	Subtotal, Direct Installation Cost	$5,194,263
Site Preparation		N/A
Buildings		N/A
	Total Direct Cost	**$11,374,710**

Indirect Costs

Engineering (10% of PEC)	$618,045
Construction and Field Expense (10% of PEC)	$618,045
Contractor Fees (10% of PEC)	$618,045
Start-up (1% of PEC)	$61,804
Performance Test (1% of PEC)	$61,804
Contingencies (3% of PEC)	$185,413
Total Indirect Cost	**$2,163,157**
Total Capital Investment (TCI)	**$13,537,867**

Direct Annual Costs

Increased Fuel Cost (calculated by scaling 2007 annual average fuel usage by the ratio of maximum annual clinker production (1,215,708 tons) to 2007 actual clinker production (1,035,283 tons)

Increased Fuel Cost (calculated by scaling 2007 annual average fuel usage to maximum actual production levels)	
Reduction in coke usage (metric ton/yr)	188,959
Heat Value (Gj / Mt)	32.510
Heat (Gj / yr)	6,143,045
Cost ($/Gj)	$1.74
Subtotal, reduction in coke cost	-$10,688,898
Reduction in coal usage (metric ton/yr)	11,076
Heat Value (Gj / Mt)	22.177
Heat (Gj / yr)	245,627
Cost ($/Gj)	$2.41
Subtotal, reduction in coal cost	-$591,962
Increase in low sulfur coal usage - Amount Required (metric ton/yr)	244,891
Heat Value (Gj / Mt)	26.266
Heat (Gj / yr)	6,432,296
Cost ($/Gj)	$5.67
Subtotal, increase in Low Sulfur Coal cost	$36,471,116
Total Direct Annual Cost (increase)	**$25,190,256**

Indirect Annual Costs

Administrative (2% TCI)		$270,757
Property Tax (1% TCI)		$135,379
Insurance (1% TCI)		$135,379
Capital Recovery	(15 year life, 7 percent interest)	$1,486,385
	Total Indirect Annual Cost	**$2,027,900**

Conclusion

Total Annualized Cost	**$27,218,156**
Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)	**13,298**
Pollutant Removed (tons SO_2/yr) - 50%	**6,649**
Cost Per Ton of Pollutant Removed	**$4,094**

Table D -11. Dry Lime Scrubbing - Control Cost Analysis Based on Projected Actual Emissions and 20% Control.

Direct Costs			
Purchased Equipment Costs			
	Dry Lime Injection System		$1,000,000
	Retrofit ESPs with Baghouse		$3,000,000
	Total Equipment Cost		$4,000,000
	Instrumentation (10% of EC)		$400,000
	Freight (5% of EC)		$200,000
	Subtotal, Purchased Equipment Cost (PEC)		$4,600,000
Direct Installation Costs			
	Foundation (6% of PEC)		$276,000
	Supports (6% of PEC)		$276,000
	Handling and Erection (40% of PEC)		$1,840,000
	Electrical (1% of PEC)		$46,000
	Piping (30% of PEC)		$0
	Insulation for Ductwork (1% of PEC)		$2,000
	Painting (1% of PEC)		$0
	Subtotal, Direct Installation Cost		$2,440,000
Site Preparation			N/A
Buildings			N/A
	Total Direct Cost		**$7,040,000**
Indirect Costs			
	Engineering (10% of PEC)		$460,000
	Construction and Field Expense (10% of PEC)		$460,000
	Contractor Fees (10% of PEC)		$460,000
	Start-up (1% of PEC)		$46,000
	Performance Test (1% of PEC)		$46,000
	Contingencies (3% of PEC)		$138,000
	Total Indirect Cost		**$1,610,000**
	Total Capital Investment (TCI)		**$8,650,000**
Direct Annual Costs			
Operating Labor			
	Operator (0.5 hr/shift, 3 shifts/day, 365 d/yr, $16/hr)		$8,760
	Supervisor (15% of operator)		$1,314
	Subtotal, Operating Labor		$10,074
Maintenance			
	Labor (0.5 hr/shift, 3 shifts/day, 365 d/yr, $16/hr)		$8,760
	Material (5% of Total Direct Cost). Increased to account for high rate of damaged bags that is expected.	$	352,000
	Subtotal, Maintenance		$360,760
Lime			
	Hydrated lime/Sulfur molar ratio, min. Ca/S		6.0
	MW of Ca(OH)2		74
	MW of SO2		64
	Purity of the Comercial lime %		96.8
	Lime Required - Short Tons		82282
	Cost ($/short ton)	$	156.00
	Subtotal, Lime		$12,836,066
	Total Direct Annual Costs		**$13,206,900**
Indirect Annual Costs			
Overhead (60% of sum of operating, supervisor, maintenance labor & materials)			$222,500
Administrative (2% TCI)			$173,000
Property Tax (1% TCI)			$86,500
Insurance (1% TCI)			$86,500
Capital Recovery	(15 year life, 7 percent interest)		$949,724
	Total Indirect Annual Cost		**$1,518,224**
Conclusion			
	Total Annualized Cost		**$14,725,124**
	Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)		**11,481**
	Pollutant Removed (tons SO_2/yr) - 20% removal, 95% uptime		**2,181**
	Cost Per Ton of Pollutant Removed		**$6,750**

Table D-12. Dry Lime Scrubbing - Control Cost Analysis Based on Projected Actual Emissions and 30% Control.

Direct Costs			
Purchased Equipment Costs			
	Dry Lime Injection System		$1,000,000
	Retrofit ESPs with Baghouse		$3,000,000
	Total Equipment Cost		$4,000,000
	Instrumentation (10% of EC)		$400,000
	Freight (5% of EC)		$200,000
	Subtotal, Purchased Equipment Cost (PEC)		$4,600,000
Direct Installation Costs			
	Foundation (6% of PEC)		$276,000
	Supports (6% of PEC)		$276,000
	Handling and Erection (40% of PEC)		$1,840,000
	Electrical (1% of PEC)		$46,000
	Piping (30% of PEC)		$0
	Insulation for Ductwork (1% of PEC)		$2,000
	Painting (1% of PEC)		$0
	Subtotal, Direct Installation Cost		$2,440,000
Site Preparation			N/A
Buildings			N/A
	Total Direct Cost		**$7,040,000**
Indirect Costs			
	Engineering (10% of PEC)		$460,000
	Construction and Field Expense (10% of PEC)		$460,000
	Contractor Fees (10% of PEC)		$460,000
	Start-up (1% of PEC)		$46,000
	Performance Test (1% of PEC)		$46,000
	Contingencies (3% of PEC)		$138,000
	Total Indirect Cost		**$1,610,000**
	Total Capital Investment (TCI)		**$8,650,000**
Direct Annual Costs			
Operating Labor			
	Operator (0.5 hr/shift, 3 shifts/day, 365 d/yr, $16/hr)		$8,760
	Supervisor (15% of operator)		$1,314
	Subtotal, Operating Labor		$10,074
Maintenance			
	Labor (0.5 hr/shift, 3 shifts/day, 365 d/yr, $16/hr)		$8,760
	Material (5% of Total Direct Cost). Increased to account for high rate of damaged bags that is expected.	$	352,000
	Subtotal, Maintenance		$360,760
Lime			
	Hydrated lime/Sulfur molar ratio, min. Ca/S		6.0
	MW of Ca(OH)2		74
	MW of SO2		64
	Purity of the Comercial lime %		96.8
	Lime Required - Short Tons		82282
	Cost ($/short ton)	$	156.00
	Subtotal, Lime		$12,836,066
	Total Direct Annual Costs		**$13,206,900**
Indirect Annual Costs			
Overhead (60% of sum of operating, supervisor, maintenance labor & materials)			$222,500
Administrative (2% TCI)			$173,000
Property Tax (1% TCI)			$86,500
Insurance (1% TCI)			$86,500
Capital Recovery	(15 year life, 7 percent interest)		$949,724
	Total Indirect Annual Cost		**$1,518,224**
Conclusion			
	Total Annualized Cost		**$14,725,124**
	Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)		**11,481**
	Pollutant Removed (tons SO_2/yr) - 30% removal, 95% uptime		**3,272**
	Cost Per Ton of Pollutant Removed		**$4,500**

Table D-13. Dry Lime Scrubbing - Control Cost Analysis Based on PTE and 20% Control.

Direct Costs			
Purchased Equipment Costs			
	Dry Lime Injection System		$1,000,000
	Retrofit ESPs with Baghouse		$3,000,000
	Total Equipment Cost		$4,000,000
	Instrumentation (10% of EC)		$400,000
	Freight (5% of EC)		$200,000
	Subtotal, Purchased Equipment Cost (PEC)		$4,600,000
Direct Installation Costs			
	Foundation (6% of PEC)		$276,000
	Supports (6% of PEC)		$276,000
	Handling and Erection (40% of PEC)		$1,840,000
	Electrical (1% of PEC)		$46,000
	Piping (30% of PEC)		$0
	Insulation for Ductwork (1% of PEC)		$2,000
	Painting (1% of PEC)		$0
	Subtotal, Direct Installation Cost		$2,440,000
Site Preparation			N/A
Buildings			N/A
	Total Direct Cost		**$7,040,000**
Indirect Costs			
	Engineering (10% of PEC)		$460,000
	Construction and Field Expense (10% of PEC)		$460,000
	Contractor Fees (10% of PEC)		$460,000
	Start-up (1% of PEC)		$46,000
	Performance Test (1% of PEC)		$46,000
	Contingencies (3% of PEC)		$138,000
	Total Indirect Cost		**$1,610,000**
	Total Capital Investment (TCI)		**$8,650,000**
Direct Annual Costs			
Operating Labor			
	Operator (0.5 hr/shift, 3 shifts/day, 365 d/yr, $16/hr)		$8,760
	Supervisor (15% of operator)		$1,314
	Subtotal, Operating Labor		$10,074
Maintenance			
	Labor (0.5 hr/shift, 3 shifts/day, 365 d/yr, $16/hr)		$8,760
	Material (5% of Total Direct Cost). Increased to account for high rate of damaged bags that is expected.	$	352,000
	Subtotal, Maintenance		$360,760
Lime			
	Hydrated lime/Sulfur molar ratio, min. Ca/S		6.0
	MW of Ca(OH)2		74
	MW of SO2		64
	Purity of the Comercial lime %		96.8
	Lime Required - Short Tons		95305
	Cost ($/short ton)	$	156.00
	Subtotal, Lime		$14,867,521
	Total Direct Annual Costs		**$15,238,355**
Indirect Annual Costs			
Overhead (60% of sum of operating, supervisor, maintenance labor & materials)			$222,500
Administrative (2% TCI)			$173,000
Property Tax (1% TCI)			$86,500
Insurance (1% TCI)			$86,500
Capital Recovery	(15 year life, 7 percent interest)		$949,724
	Total Indirect Annual Cost		**$1,518,224**
Conclusion			
	Total Annualized Cost		**$16,756,579**
	Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)		**13,298**
	Pollutant Removed (tons SO_2/yr) - 20% removal, 95% uptime		**2,527**
	Cost Per Ton of Pollutant Removed		**$6,632**

Table D-14. Dry Lime Scrubbing - Control Cost Analysis Based on PTE and 30% Control.

Direct Costs			
Purchased Equipment Costs			
	Dry Lime Injection System		$1,000,000
	Retrofit ESPs with Baghouse		$3,000,000
	Total Equipment Cost		$4,000,000
	Instrumentation (10% of EC)		$400,000
	Freight (5% of EC)		$200,000
	Subtotal, Purchased Equipment Cost (PEC)		$4,600,000
Direct Installation Costs			
	Foundation (6% of PEC)		$276,000
	Supports (6% of PEC)		$276,000
	Handling and Erection (40% of PEC)		$1,840,000
	Electrical (1% of PEC)		$46,000
	Piping (30% of PEC)		$0
	Insulation for Ductwork (1% of PEC)		$2,000
	Painting (1% of PEC)		$0
	Subtotal, Direct Installation Cost		$2,440,000
Site Preparation			N/A
Buildings			N/A
	Total Direct Cost		**$7,040,000**
Indirect Costs			
	Engineering (10% of PEC)		$460,000
	Construction and Field Expense (10% of PEC)		$460,000
	Contractor Fees (10% of PEC)		$460,000
	Start-up (1% of PEC)		$46,000
	Performance Test (1% of PEC)		$46,000
	Contingencies (3% of PEC)		$138,000
	Total Indirect Cost		**$1,610,000**
	Total Capital Investment (TCI)		**$8,650,000**
Direct Annual Costs			
Operating Labor			
	Operator (0.5 hr/shift, 3 shifts/day, 365 d/yr, $16/hr)		$8,760
	Supervisor (15% of operator)		$1,314
	Subtotal, Operating Labor		$10,074
Maintenance			
	Labor (0.5 hr/shift, 3 shifts/day, 365 d/yr, $16/hr)		$8,760
	Material (5% of Total Direct Cost). Increased to account for high rate of damaged bags that is expected.	$	352,000
	Subtotal, Maintenance		$360,760
Lime			
	Hydrated lime/Sulfur molar ratio, min. Ca/S		6.0
	MW of Ca(OH)2		74
	MW of SO2		64
	Purity of the Comercial lime %		96.8
	Lime Required - Short Tons		95305
	Cost ($/short ton)	$	156.00
	Subtotal, Lime		$14,867,521
	Total Direct Annual Costs		**$15,238,355**
Indirect Annual Costs			
Overhead (60% of sum of operating, supervisor, maintenance labor & materials)			$222,500
Administrative (2% TCI)			$173,000
Property Tax (1% TCI)			$86,500
Insurance (1% TCI)			$86,500
Capital Recovery	(15 year life, 7 percent interest)		$949,724
	Total Indirect Annual Cost		**$1,518,224**
Conclusion			
	Total Annualized Cost		**$16,756,579**
	Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)		**13,298**
	Pollutant Removed (tons SO_2/yr) - 30% removal, 95% uptime		**3,790**
	Cost Per Ton of Pollutant Removed		**$4,421**