Appendix 9C

Lafarge BART Technical Analysis

PROPOSED BEST AVAILABLE RETROFIT TECHNOLOGY (BART) FOR THE LAFARGE FACILITY IN ALPENA, MICHIGAN

Prepared for:
Lafarge
1435 Ford Avenue
Alpena, MI 49707

Prepared by:
RTP Environmental Associates
304A West Millbrook Road
Raleigh, North Carolina 27609

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1.0 EXECUTIVE SUMMARY

The U.S. Environmental Protection Agency (EPA) published final amendments and guidelines to its 1999 regional haze rule on July 6, 2005 (70 FR 39104). Under this regulation, certain existing stationary sources that emit visibility impairing pollutants must install and operate the Best Available Retrofit Technology (BART). BART is required for sources that fit specific criteria, as discussed below, and that "may reasonably be anticipated to cause or contribute" to visibility impairment in any Class I area. The determination of what constitutes BART is made on a case-by-case basis considering technical feasibility, costs of compliance, energy impacts, and the modeled reduction in visibility impacts.

The BART requirement only applies to sources included in the specific source categories listed in CAA Section 169A(g)(7) that also meet the time frame and emission level thresholds specified in the BART Guidelines found at 40 CFR Part 51, Appendix Y. Once the emission units in the applicable source categories have been identified, the second step is to determine whether the units fall within the 15-year time frame established by the BART Guidelines. Therefore, BART applicability focuses on sources that were "in existence" on August 7, 1977 and not "in operation" before August 7, 1962. The third step of identifying BART-eligible emission sources is determining whether the source meets a 250 ton per year emission threshold. The 250 ton per year threshold is applied facility-wide. To be BART-eligible, the combined potential to emit of the emission units meeting the source category and operational date tests must be in excess of 250 tons per year for any single visibility impairing pollutant. Visibility-impairing pollutants include sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter (PM).

Lafarge owns and operates a portland cement manufacturing facility in Alpena, Michigan. Portland cement manufacturing is one of the specific source categories listed in Section 169A. In addition, Lafarge operates five cement kilns that were constructed and, based upon available information, became operational between August 7, 1962

and August 7, 1977. Since the potential to emit of the five kilns is in excess of 250 tons per year for one or more visibility impairing pollutants, the kilns are considered to be BART-eligible.

Based upon source-specific modeling of the Lafarge facility, the Michigan Department of Environmental Quality (MDEQ) has determined that the five BART-eligible emission units at Lafarge "may reasonably be anticipated to cause or contribute" to a visibility impairment at the Seney Wilderness Class I area. This source-specific modeling indicates that the emissions from Lafarge change the 24-hour background visibility at Seney by more than 0.5 deciviews (the deciview is the accepted metric for expressing visibility and changes in visibility). The five kilns at Lafarge are therefore subject to BART.

Once a source is determined to be subject to BART, a BART review is required for each visibility-impairing pollutant emitted. The BART review must identify the best system of continuous emission reduction considering the following five statutory factors: 1) the cost of compliance, 2) energy and non-air quality environmental impacts, 3) any existing pollution control in use at the source, 4) the remaining useful life of the source, and 5) the degree of visibility improvement reasonably anticipated from implementing BART.

This document presents the procedures and results of the BART review conducted for the five cement kilns at the Lafarge Alpena facility. The BART review focused on emissions of SO_2 and NOx and did not consider emissions of PM_{10} as PM_{10} emissions are subject to the Maximum Achievable Control Technology (MACT) standard for portland cement (40 CFR 63.1340). The states may assume that the level of control required by a MACT standard meets BART (see 70 FR 39164).[1]

[1] PM_{10} emissions were included in the evaluation of visibility impacts. However, PM_{10} control options were not evaluated as the MDEQ has agreed that the Alpena facility's compliance with the MACT standards for particulates satisfies the BART requirements.

The results presented herein demonstrate that wet scrubbers on the two large kilns (K22 and 23) represent BART for control of SO_2 and that selective non-catalytic reduction (SNCR) on all five kilns represent BART for control of NOx. The analysis demonstrates that the addition of SO_2 controls on the three smaller kilns would result in minimal improvement in visibility at a very high cost. Table 1-1 presents the proposed BART for the Lafarge Alpena facility.

Table 1-1. Proposed BART for Lafarge Alpena

Emission Unit	Proposed BART	Pollutant(s) Controlled	Proposed BART Emission Limit	Visibility Improvement on 98th Percentile Day (delta deciview)	Class I Area Impacted
Kiln 19	SNCR	NOx	See note	See note	Seney
Kiln 20	SNCR	NOx	See note	See note	Seney
Kiln 21	SNCR	NOx	See note	See note	Seney
Kiln 22	SNCR, Wet scrubbing	NOx, SO_2	See note	See note	Seney
Kiln 23	SNCR, Wet scrubbing	NOx, SO_2	See note	See note	Seney
Kilns 19-23	See above control for each kiln	NOx, SO_2	29.4 TPD NOx 53.8 TPD SO_2	-0.83[a]	Seney

Note: Lafarge is proposing facility-wide BART limits. The proposed BART limits are listed once, for all five kilns. The facility-wide limits were developed in reliance upon the MDEQ's recognition that Appendix Y, 40 CFR Part 51 provides:

> *You should consider allowing sources to "average" emissions across any set of BART eligible emission units within a fenceline, so long as the emission reductions from each pollutant being controlled for BART would be equal to those reductions that would be obtained by simply controlling each of the BART-eligible units that constitute BART-eligible source.*

TPD = tons per day.
[a]2003 meteorology.

2.0 BACKGROUND INFORMATION

2.1 Facility Location

The Lafarge facility is located on the western shore of Lake Huron in northeastern Michigan in Alpena County. The approximate Lambert Conformal Conic (LCC) coordinates of the facility are 1,066.778 kilometers east and 641.461 kilometers north. Figure 2-1 shows the location of the facility on the Alpena 7.5 minute USGS quadrangle.

2.2 Description of Operations

The plant includes five dry process kilns, a quarry, raw material grinding and storage, finish grinding, and cement loading operations. Kiln Nos. 19-21 are collectively referred to as Kiln Group 5 (KG5) while the larger kilns (Kiln Nos. 22 & 23) are referred to as Kiln Group 6 (KG6). The facility is defined as a major source of air pollution per Rule 336.1211 of the Michigan Administrative Rules for Air Pollution Control and under the Federal Prevention of Significant Deterioration regulation of 40 CFR 52.21. The facility operates under Renewable Operating Permit (ROP) No. MI-ROP-B1477-2006b.

The production of portland cement at Alpena is a long-dry process (i.e., the facility does not have pre-heaters to pre-calcine raw materials before entering the kilns). Limestone is quarried on site. Other primary raw material components (aluminum, silica, and iron) are transported to the facility via barge, truck, and rail. The raw materials are conveyed by belt to one of two dryers prior to being processed in the raw grind operation. Once dried and ground, the raw materials are stored in silos. When needed for production, the raw materials are withdrawn from the blending silos and fed to the kilns.

The Alpena facility uses a combination of coal and petroleum coke to provide heat to the kilns. Natural gas is also used as a “start-up” fuel. The heat from the hot combustion gases is transferred to the raw materials in a countercurrent manner. The materials are slowly moved to the lower end by rotation of the kilns. As they move

Figure 2-1. Location of the Lafarge Alpena Facility

down the kilns, the materials are changed to cementitious or hydraulic minerals because of the increasing temperature. The exhaust gases exit the kilns at the elevated end. The exhaust gases are controlled with baghouses prior to release to the atmosphere.

Once the cementitious materials (clinker) leave the kilns, the last component of the pyroprocessing system is the clinker cooler. In this step, the clinker is rapidly cooled using air to lock in desirable product qualities by freezing mineralogy. The clinker cooler also enables the material to be cooled for further processing. The final step in the manufacture of portland cement at Alpena involves a sequence of blending and grinding that transform the clinker into finished portland cement. Gypsum and other materials are added as needed to impart specific product properties. These materials and the clinker are mixed and milled in the finish mill. The final product is then stored in either land or marine silos prior to shipment. The cement is shipped off-site via trucks, railcars, and barges.

2.3 Class I Area Evaluated

Class I areas are national parks and wilderness areas in which visibility is more stringently protected under the Clean Air Act than any other areas in the United States. Class I areas that are located within 300 km of a BART-eligible source are typically evaluated for visibility impacts.[2]

There is one Class I area located within 300 km of the Lafarge site that required evaluation: the Seney Wilderness Area. Seney is located 250 km to the northwest of the Lafarge facility. Figure 2-2 shows the location of this Class I area with respect to the Lafarge facility. There is no other Class I area located within 500 km of the Lafarge facility. The next closest Class I area is Isle Royale National Park which is located 520 km northwest of Lafarge Alpena.

[2] Visibility Improvement State and Tribal Association of the Southeast (VISTAS) Regional Planning Organization (RPO), "Protocol for the Appication of the CALPUFF Model for Analysis of Best Available Retrofit Technology (BART), December 22, 2005 (with revisions January 23 and March 9, 2006).

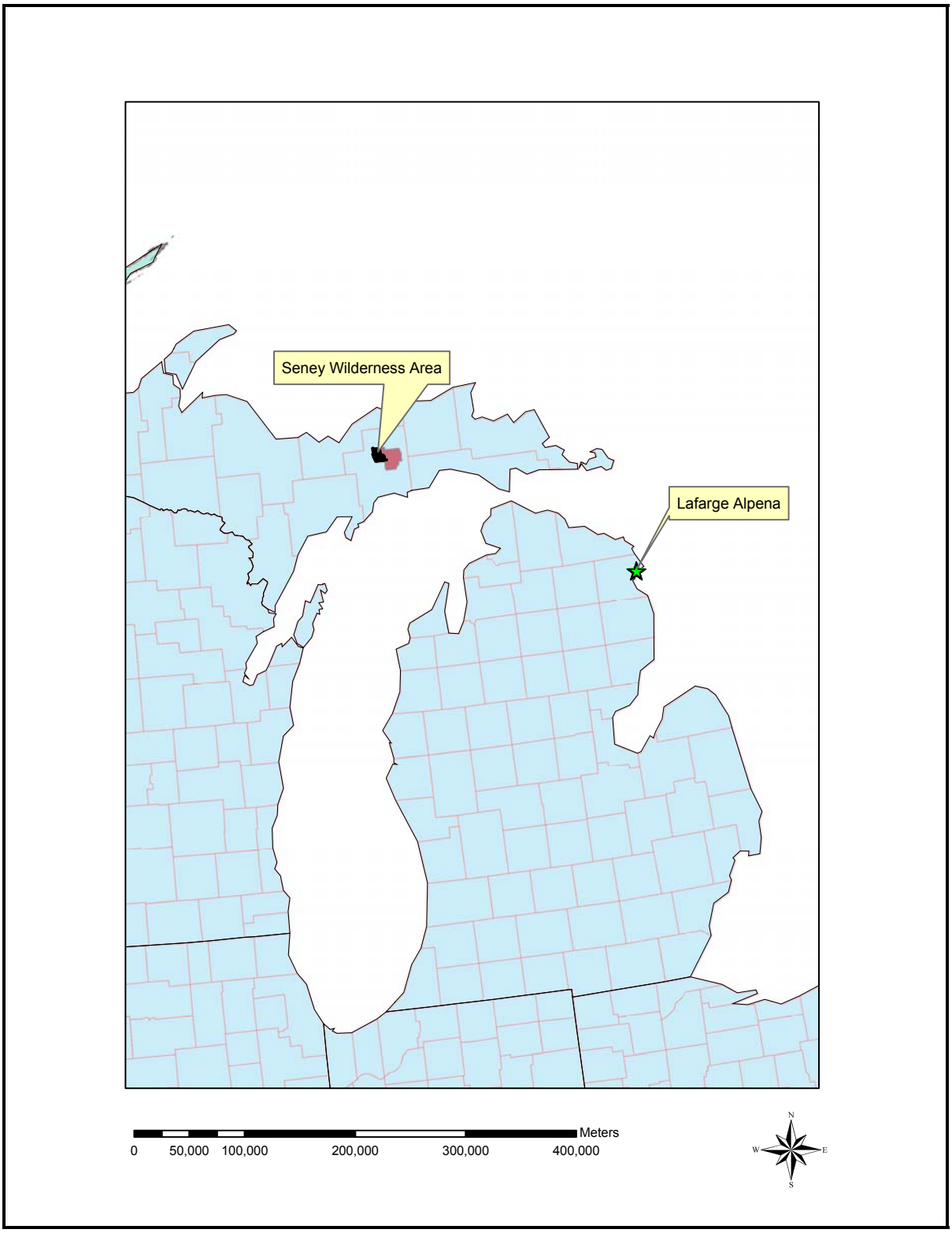

Figure 2-2. Location of the Lafarge Alpena Facility and the Seney Class I Area

3.0 BART SELECTION PROCESS

Five basic steps were taken in selecting BART for the Lafarge Alpena kilns:

- All available retrofit control technologies were identified;
- Technically infeasible options were eliminated;
- The technically feasible options were ranked in order of control effectiveness:
- The energy, environmental, and economic impacts of each control were evaluated; and
- The visibility impact of each control alternative was determined (see 70 FR 39164).

Based on this process, Lafarge has proposed BART limits for the Alpena kilns as shown in Table 1-1 of this report.

As discussed previously, the BART analysis for the Alpena plant focused on SO_2 and NOx controls for the cement kilns. Since the control options for these pollutants are basically unrelated, each pollutant is addressed individually. However, because the impacts of SO_2 and NOx on visibility are similar, the proposed BART limits are based on a combined SO_2 and NOx control strategy (see Section 3.3).[3]

3.1 <u>SO_2 BART Analysis</u>

Step 1 – Identify Potentially Applicable SO_2 Control Options

Lafarge has identified SO_2 control options for retrofit to the Alpena kilns. Based on review of U.S. EPA's RBLC (RACT, BACT, and LAER Clearinghouse) database, industry practice, recently issued permits for cement kilns, and considering the potential for technology transfer, the SO_2 control technologies potentially available[4] for retrofit to the Alpena kilns include:

[3] Model results indicate that SO_2 and NOx emissions contributed equally to visibility reduction at Seney. Lafarge therefore concluded that both SO_2 and NOx control strategies would need to be implemented to yield appreciable modeled visibility improvement. Modeling output data supporting this conclusion are provided in Appendix E.

[4] Available retrofit control options are those air pollution control technologies with a practical potential for application to the emissions unit and the regulated pollutant under evaluation70 FR 39614]. A source owner is not required to purchase or construct a process or control device that has not already been demonstrated in practice. The term "demonstrated in practice" is not specifically defined in the BART rule, but EPA proposed to define this term to

- Duct Sorbent Injection; and
- Flue Gas Desulfurization.

The following subsections describe each of these technologies and their potential applicability to the Alpena kilns.

Duct Sorbent Injection Systems. In general, sorbent injection systems consist of atomizing a reagent slurry or solution into fine droplets into the exhaust gas duct upstream of a particulate control device. In situations where there is limited ability to dry injected reagent, moist reagent powders (typically hydrated lime) are injected. Examples of alkaline reagents used in sorbent injection systems include magnesium hydroxide, hydrated lime, and sodium carbonate. The injected reagent reacts with SO_2 in the gas stream. Once dry, the byproduct of this reaction consists of fine sulfate and sulfite particles along with unreacted reagent. These particles are collected in a downstream particulate control device and either disposed of or reintroduced into the process.

Sorbent injection systems, such as Envirocare International's Micro-Fine Lime system, have been applied on cement kilns in recent years to reduce SO_2 emissions. With respect to the kilns at Alpena, a sorbent injection system could be installed upstream of the existing baghouse on each kiln. However, such systems could only be expected to reduce SO_2 emissions by an estimated 25 percent. This efficiency is a function of the relatively low baghouse inlet temperatures at Alpena coupled with the limited duct residence time available for drying of injected reagent. The Alpena kilns are equipped with waste heat boilers designed to recover energy from the kiln exhaust gas. The resultant low temperature at the waste heat boiler exit affects the effectiveness of sorbent injection technologies as discussed below. Sorbent injection upstream of the

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include any technology that meets the following criteria: (1) it has been installed and operating continually for at least 6 months on an emissions unit(s) which has been operating at least at 50 percent of design capacity during that period of time; and (2) its performance has been verified during that 6 month period with a performance test or performance data while operating under a load that coincides with either the operation of the emissions units served by the control technology at their PTE, or 90 percent of the control technology's design specifications [61 FR 38249]. This definition is assumed to be relevant for purposes of this BART analysis.

waste heat boilers is not feasible due to the potential for plugging and erosion of the boilers by injected sorbent.

The effectiveness of sorbent injection is a function of the moisture content and drying time of injected reagent. Because of the gas temperatures downstream of the waste heat boilers and the limited duct residence time, a reagent slurry cannot be injected into these ducts at Alpena. The moisture in a slurry cannot be evaporated quickly enough to prevent either plugging of the baghouses or the formation of significant deposits of injected reagent on the duct walls. With limited ability to dry slurry, the moisture content of any injected reagent must be kept to a minimum. This factor limits the effectiveness of sorbent injection technologies for the Alpena kilns to an estimated 25% SO_2 control efficiency on a short-term basis. Coupled with an on-stream factor of 80%, Lafarge estimates that the overall SO_2 control efficiency is 20% for this technology.

Flue Gas Desulfurization (FGD). A review of technical publications and USEPA guidance shows that one of the most effective add-on control technologies for SO_2 control involves scrubbing with an aqueous alkaline slurry or solution. This type of add-on control technology is commonly referred to as wet flue gas desulfurization.

Another type of widely-used flue gas desulfurization technology is known as dry or semi-dry scrubbing. This is also an effective SO_2 control technology because it uses water to enhance the reactions between SO_2 and the alkaline reagent used. It has the advantage of producing a dry byproduct which is may be easier to manage depending on the application. The following subsections provide additional information on wet and semi-dry FGD systems and their potential applicability to the Lafarge Alpena cement kilns.

Wet Flue Gas Desulfurization. Wet flue gas desulfurization (FGD) systems are characterized by low flue gas outlet temperatures and saturated flue gas conditions, and a wet sludge reaction product which is dewatered before reuse or disposal. Wet FGD systems typically are installed with a particulate matter

control device upstream of the scrubber so that the fly ash and scrubber reaction products are collected separately. The following discussion reviews wet scrubbing technologies that are potentially applicable to the Alpena kilns.

Wet Limestone with Forced Oxidation (LSFO) – Limestone with forced oxidation (LSFO) is the type of wet limestone FGD process that is most commonly used today. A conventional wet limestone FGD system forms a scrubber byproduct composed mostly of calcium sulfite ($CaSO_3$) solids. The LSFO process produces a scrubber byproduct with very little $CaSO_3$ in the byproduct. Instead, the byproduct from an LSFO FGD system has a calcium sulfate dihydrate ($CaSO_4 \cdot 2H_2O$ or gypsum) content in excess of 90 percent. The high gypsum content of the scrubber byproduct makes the solids easier to dewater, improves the reliability of the scrubbing process, and provides the potential for byproduct reuse. For most applications, these factors result in lower overall costs of control than a conventional, unoxidized limestone scrubbing process.

In the LSFO process, hot flue gas exiting the particulate control device enters an absorber where a slurry of limestone and gypsum is sprayed into the flue gas.[5] The SO_2 in the flue gas is absorbed into the slurry which is alkaline relative to the absorbed SO_2. The flue gas exits the absorption tower through a mist eliminator to remove entrained droplets. The absorbed SO_2 (now mostly dissolved sulfite) contained in the slurry drains into a recirculation tank located at the bottom of the spray tower. The sulfite is subsequently oxidized to sulfate in the recirculation tank, and following the oxidation step, it precipitates as calcium sulfate dihydrate. This process is called "forced oxidation," and involves bubbling air through the slurry to force the oxidation of sulfite to sulfate. A portion of the slurry

[5] There are a number of variations on the design of a limestone forced oxidation scrubbing system that may differ slightly from the system described here. However the basic principals of SO_2 control and byproduct formation are

in the recirculation tank is pumped back into the spray tower, and a portion is removed. The removed slurry is dewatered, typically using hydrocyclones followed by a horizontal belt filter. The final gypsum product may be used in a number of applications. In the case of Alpena, depending on process chemistry and gypsum quality, it may be possible to reuse the byproduct gypsum by adding it to final cement product.

For this BART analysis, an overall SO_2 removal efficiency of 81% is assumed for the LSFO process. This efficiency represents a short-term 90% SO_2 control efficiency coupled with an estimated system on-stream factor of 90%. The control efficiency is typical of control efficiencies for wet scrubbers applied in this industry. The estimated on-stream factor reflects both limited experience with wet FGD systems in the cement industry along with the expected impacts on reliability of a single-module FGD system. An overall 81% control efficiency is consistent with Lafarge's experience on a cement kiln in Europe that has been retrofitted with an FDG system. Lafarge has not be able to identify reliable published control efficiency data on other retrofitted FGD systems on long dry cement kilns.

Wet Lime FGD Process – In the wet lime FGD process, flue gas leaving the particulate control device enters an absorber tower. The SO_2 is removed from the flue gas when the gas comes into contact with an alkaline slurry of hydrated lime and calcium sulfite. The scrubbed flue gas exits the absorption tower through a mist eliminator to remove entrained droplets prior to gas exiting the system. The reaction products (i.e., scrubber slurry composed primarily of calcium sulfite) are withdrawn from the absorber and then sent for dewatering and further processing. This includes thickening the sulfite sludge and fixating the sludge or filter cake

the same. The differences are principally due to alternative designs that have different features and benefits and the choice of technology is often a function of site-specific considerations and individual company preferences.

with lime and/or fly ash. The blend of fly ash, lime, and filter cake is then conveyed to a truck loading facility for disposal.

A significant disadvantage of the wet lime FGD system as compared to the LSFO system is the higher operating costs, primarily due to the high lime reagent costs and higher byproduct disposal costs. The production of lime for this process also has important secondary environmental impacts as compared to the LSFO process, including the consumption of natural gas or other fuels for calcining raw limestone.

The wet lime FGD process, like the LSFO process, can be designed for short-term SO_2 removal efficiencies of 90%. However, due to the nature of the byproduct produced by this system, it is not considered a good choice for use at Alpena. The production of byproduct gypsum using the LSFO is much better match and it also provides cost advantages. For these reasons, wet lime scrubbing is not considered further in this BART assessment. Because LSFO is the best option from technical and environmental perspective, and because it provides equivalent levels of performance, this is the only wet scrubbing technology that is evaluated in this BART analysis.[6]

Dry or Semi-Dry Flue Gas Desulfurization. Spray dryers (also referred to as "semi-dry" FGD systems) are characterized by flue gas temperatures above the saturation point (i.e., the gas exiting the scrubber is at less than 100% relative humidity). Dry and semi-dry FGD systems typically use a particulate control system downstream of the FGD system to collect both scrubber byproduct and fly ash such that the fly ash and the FGD reaction products are commingled into a single byproduct stream.

[6] This approach is consistent with the BART rule which states:"It is not necessary to list all permutations of available control levels that exist for a given technology - the list is complete if it includes the maximum level of control each technology is capable of achieving." [70 FR 39164]

In the spray drying process, hot flue gases enters a spray dryer vessel. Within the spray dryer, a finely atomized slurry of lime and recycled ash is sprayed into the flue gas stream. The SO_2 in the flue gas reacts with the lime and any alkali present in the fly ash to form sulfur salts (mostly $CaSO_3$). As the SO_2 reacts with the slurry, the water in the droplets evaporates forming solid particles, raising the flue gas moisture content, and lowering the flue gas temperature. A baghouse downstream of the spray dryer removes the dry solid reaction products and fly ash before the scrubbed gas is released to the atmosphere. A portion of the collected reaction products and fly ash solids is recycled to the spray dryer reagent feed system. The remaining solids are removed for reuse or disposal.

Other semi-dry technologies involve the use of separate humidification and reagent injection steps in a fluidized bed reactor. In this reactor, the elevated humidity promotes the reaction between gas-phase SO_2 and the semi-dry alkaline reagent. Possible reagents used in this type of system include lime and soda ash. Soda ash is less desirable because the sodium-sulfur byproducts (i.e., sodium sulfate and sodium sulfite) have a high level of solubility and thus, are more difficult to dispose of in an environmentally sound manner.

Like spray drying, the reaction byproducts from the semi-dry technologies are typically collected in a fabric filter downstream of the reactor vessel. Some of the collected material is recycled to the reactor and a portion is sent to disposal. In the case of the Alpena plant, this reactor would have to be located upstream of the existing baghouse or a new second baghouse would need to be constructed.

Step 2 – Eliminate Technically Infeasible Control Options

Of the SO_2 control options identified in this BART analysis, duct sorbent injection and wet scrubbing are technically feasible for retrofit application to the cement kilns at the Lafarge Alpena plant. The various dry scrubbing options are a poor choice for Alpena

and they are deemed infeasible for several reasons. First, there is insufficient space in the flue gas path for installation of a dry scrubber. While it may be theoretically possible to install dry scrubbers on the Alpena kilns, it is practically infeasible. Construction would involve large, complex duct runs, the need for additional gas fans, and complex duct/control system configurations. The cost of such a system would result in a dry FGD system that costs as much or more as a wet FGD system while providing less effective SO_2 removal.

Second, the presence of the waste heat boilers in the gas path makes dry scrubbing a poor choice for application to the kilns at Alpena. The reduction in gas temperature by the waste heat boilers limits the applicability of dry scrubber systems because less water can be used in the scrubbing process. When less water is used, dry scrubbing tends to be less effective.

Finally, the effect of collecting removed SO_2 in the kiln baghouses on the overall sulfur balance in the kilns presents a problem. Because much of the cement kiln dust (CKD) collected in the baghouses is recycled to the kiln, capturing and returning large amounts of sulfur to the process will result in reduced control effectiveness for these technologies. Alternatively, control efficiencies can be maintained at design levels at the expense of increased rates of CKD disposal to remove sulfur from the kiln system. Wet scrubbing is a better option because the gypsum byproduct can be added to the final product from the plant, thus eliminating the production of additional waste material as a result of installing an SO_2 control system.

Step 3 – Rank Feasible SO_2 Control Options

The most effective, technically feasible SO_2 control option for the Alpena kilns is wet FGD at 81% overall SO_2 control efficiency (90% control and 90% on-stream factor). The least effective option SO_2 control option identified for the Alpena kilns is the use of duct sorbent injection at an overall SO_2 control efficiency of 20% (25% control and 80% on-stream factor).

Step 4 – Evaluate Feasible Control Options

The results of the visibility impact analysis performed for the Lafarge Alpena kilns show that both SO_2 and NOx impacts on visibility are similar when compared on a mass emissions basis (i.e., SO_2 and NOx reductions both result in similar visibility improvements per ton of emissions reduction). For this reason, Lafarge has evaluated the effectiveness, costs, and energy and environmental impacts of the technically feasible SO_2 and NOx control technologies identified in this BART analysis together and used this assessment to select BART based on a combination of SO_2 and NOx controls. The results of this combined SO_2 and NOx assessment are contained in Section 3.4.

3.2 NOx BART Analysis

Step 1 – Identify Potentially Applicable NOx Control Options

Lafarge has identified possible NOx control options for retrofit to the Alpena kilns. Based on review of U.S. EPA's RBLC (RACT, BACT, and LAER Clearinghouse) database, industry practice, recently issued permits for cement kilns, and considering the potential for technology transfer, the available NOx control technologies that are potentially applicable for retrofit to the Alpena kilns include:

- Process Optimization
- Low NOx Burners;
- Selective non-catalytic NOx reduction (SNCR);and
- Selective catalytic NOx reduction (SCR).

The following subsections describe each of these technologies and their potential applicability to the Alpena kilns.

Process Optimization. Any effort that is related to reducing the amount of fuel fired in a cement kiln can be characterized as process optimization since reduced fuel consumption (e.g., improved fuel efficiency) generally results in reduced NOx emissions. The Lafarge kilns have been upgraded over the years to incorporate enhanced process monitoring systems, advanced computer controls, and necessary instrumentation to improve overall kiln operation. The baseline and projected NOx

emission rates from the Alpena kilns reflect the impact that process optimization has had on reducing NOx emissions. Since process optimization is a technically feasible NOx control technique that is currently being used by the facility, it is not considered further in this analysis (i.e., this technology cannot be retrofit to the Alpena kilns and its effects are already included in the baseline NOx emissions from the facility).

Low NOx Burners. Low NOx burner designs limit NOx formation by lowering the burner flame temperature, minimizing residence time at peak temperatures, and reducing the flame aggressiveness within the combustion zone. These burner designs typically introduce fuel in a sub-stoichiometric (lean) air-to-fuel ratio (generally 6 to 10 percent) at the primary burner inlet to reduce the combustion zone temperature and create an air-starved flame. Secondary air inlets introduce more supplemental air beyond the primary flame to complete combustion. The goal of low NOx burner technology is to create an ignition of the fuel in an oxygen deficient environment, thereby creating less NOx.

In many industries using conventional steam boilers, the implementation of low NOx burners has been very successful. However, in cement manufacturing, the success of low NOx burners is limited because much higher burning zone temperatures (as compared to the combustion temperature range found in industrial and utility boilers) are essential to achieve acceptable product quality. Lafarge is currently in the process of installing low-NOx burners on the Alpena kilns. Thus far, two of the five kilns have been fitted with low-NOx burner systems, and the installation of these low-NOx burner systems influence the NOx reductions that are achievable relative to baseline emissions for BART purposes.

Selective Non-Catalytic Reduction (SNCR). SNCR is an add-on control technology that involves injection of aqueous or anhydrous ammonia (NH_3), or urea (urea is composed of two attached ammonia molecules) into the gas stream. The injected ammonia is converted by OH* free radicals to ammonia free radicals (i.e., NH_2*), which react with NOx to form N_2 and H_2O. The optimum temperature range for this reaction is

1,600ºF to 1,900ºF. Above 1,900ºF, the amount of NH_3 that oxidizes to NOx increases, and, in turn, the NOx reduction performance deteriorates. Both laboratory work and field data show NH_3 slip[7] to be a strong function of temperature. At temperatures at or above 1,900ºF, unreacted NH_3 emissions decrease due to the NH_3 oxidation to NOx. At temperatures at or below 1,600ºF, unreacted NH_3 emissions may rapidly increase. At Alpena, NH_3 can be injected into the kiln in a region that operates between 1,600ºF and 1900ºF. This temperature window is appropriate for SNCR application.

The following factors influence the control effectiveness of SNCR:

- Temperature and oxygen availability (i.e., the NH_3 injection location);
- The baseline, or uncontrolled NOx concentration;
- Mixing;
- Reagent Ratio (i.e., the NH_3 to NOx molar ratio at the injection point);
- NH_3 accumulation;
- Excess ammonia emissions; and
- Ammonium salt formation.

Based on the current state of knowledge, these technical differences usually do not result in an SNCR system's "inability to perform" but instead present a "level of performance" question (i.e., generally, the central issue is the exact level of NOx reduction that can be achieved when SNCR is applied).

For SNCR to work effectively, the gas stream being treated must have a relatively high concentration of NOx as opposed to other potential reactants with which NOx would compete with to react with NH_3. The presence of competing reactants in the gas stream may result in less NH_3 to convert NOx to its non-polluting forms. This would reduce the effectiveness of the SNCR process.

Second, the desirable SNCR chemical reactions are most effective in a temperature range between 1,600°F and 1,900°F. Above the high end of the SNCR temperature range, the NOx reduction efficiency degrades dramatically; in fact, at higher

[7] "Slip" is a term used to refer to emissions of unreacted ammonia from SNCR and SCR processes.

temperatures, the injected reagent can oxidize and actually increase NOx emissions. Below the low end of the temperature range, the reaction rates are not rapid enough for the injected reagent to react completely. Therefore, selection of the proper temperature range for ammonia or urea injection is critical to achieving optimum performance of SNCR.

Finally, SNCR requires an oxidizing, or fuel-lean atmosphere to effectively reduce NOx emissions. In a fuel-rich, or reducing environment, partially oxidized fuel (e.g., CO) competes with NH_3 for OH* radicals, thus reducing NOx control effectiveness. In addition, ammonia interferes with the complete oxidation of organic compounds in the fuel, potentially causing a rise in CO emissions. These three conditions must be met for SNCR to be most effective in NOx reduction.

The successful application of SNCR also depends on the accurate injection of the optimum quantity of reagent NH_3. Insufficient reagent will not result in effective control, while excess reagent will result in excessive ammonia slip. Ammonia is typically injected in approximately equal molar quantities relative to the NOx present in the gas stream. While this injection ratio can theoretically result in conversion of 50% or more of the NOx with an ammonia slip of 10 ppm or less, there is a strong potential for the formation of a detached plume resulting from the presence of chlorides and sulfates in the exhaust gas stream. These compounds are present in the raw materials and are released in the kiln system.

In recent years, SNCR has been applied to a number of cement kilns in both the U.S. and internationally. However, nearly all of these applications have been on modern preheater/precalciner kilns and only limited testing has been conducted on long dry kilns similar to those at the Alpena plant. The key reason for this is the location within the kiln system where reagent injection occurs. In a preheater/precalciner kiln, reagent injection occurs at the exit of the kiln in the lower part of the preheater tower. This injection location is readily accessible using conventional injection technology. In a long-dry kiln, injection must occur mid-kiln because this is where the gas temperature is

in the proper range for the NOx reduction reactions to occur. Specialized injection systems are required to allow reagent injection in a mid-kiln location.

Lafarge has completed an engineering assessment and determined that SNCR can be applied to the Alpena kilns. Based on this assessment, Lafarge estimates that SNCR, in combination with the low-NOx burners now being installed on the Alpena kilns, can achieve 35% NOx reductions on Kiln Group 5 and 40% NOx reductions on Kiln Group 6 (relative to current baseline NOx emissions). These reduction efficiencies are consistent with the reduction efficiencies that have been observed on the limited SNCR testing and operation for other long-dry kilns.

Selective Catalytic Reduction (SCR). Like SNCR, SCR systems use NH_3 to chemically convert NOx to molecular N_2 (i.e., the same form of nitrogen that comprises 79% of the air we breathe). However, as the name indicates, SCR uses a catalyst to promote the selective reaction of NOx and ammonia. Ammonia injected into the gas stream reacts with NOx and the SCR catalyst enables these reactions to occur at lower temperatures than are possible with SNCR. While catalysts can operate over a range of temperatures, the optimal temperature range for SCR applications is between 570º to 750ºF, well below the 1,600ºF to 1,900ºF temperature range for SNCR reactions discussed previously.

The SCR catalytic reactions occur on the surface of the catalyst structure. However, the catalyst structures are not composed of simple, flat surfaces. The catalyst is designed to have a series of large openings termed “macropores” and small openings termed “micropores.” These macropores and micropores maximize the surface area of the catalyst available for reaction with NOx and NH_3.

A set of SCR catalyst beds is placed in series in a large vessel located in a part of the process where the gas temperatures are in the appropriate range during routine

operation. The NH_3[8] is injected at a controlled rate upstream of the catalyst using an injection grid designed to ensure relatively even NH_3 distribution, good mixing, and minimum NH_3 slip. The injected NH_3 reacts with NOx 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 NOx) to form N_2 and water.

There is only one large scale installation of SCR on a cement plant in the world with any significant operating experience.[9] This installation is at the Solnhofen Cement Works in Germany. This is a preheater kiln with the SCR system located at the exit of the preheater tower. In this location, the kiln exhaust gas temperature is in excess of 610ºF which is in the correct range for SCR to function.[10] There is no equivalent location for installing an SCR system in Alpena's long dry kilns. The raw materials used in the Solnhofen plant differ significantly from those at Alpena. The Solnhofen kiln raw materials contain minimal amounts of sulfur and alkali while the Alpena kiln raw materials contain appreciable amounts of both. These compounds are significant because they contribute to SCR problems such as catalyst deactivation and fouling. In addition, the presence of sulfur compounds can lead to downstream problems such as increased particulate emissions and plugging and corrosion of heat exchangers and particulate control equipment.

Lafarge has assessed the publicly available information regarding the Solnhofen SCR application and has determined that the long-term demonstrated performance of the SCR system at Solnhofen shows a demonstrated NOx reduction efficiency that is

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[8] The NH_3 reagent can be in the form of an aqueous solution (typically 25 wt. % NH_3), anhydrous NH_3, or as a product of urea decomposition.

[9] A second commercial-scale SCR system has been installed in Europe on a cement kiln at Cementeria di Monselice. This unit began operation in mid-2006. Very little data are available on this application, but what data are available show that it differs significantly from the Alpena kilns. The Monselice SCR system is installed on a pre-heater, pre-calciner kiln system. There is no equivalent location in the Alpena kilns that would allow installation of such a system.

[10] When it was operational, the SCR system at the Solnhofen Cement Works would be bypassed if the flue gas temperature dropped below 320ºC or about 610ºF.

similar to the reduction efficiencies expected to be achieved using SNCR.[11] These data are consistent with the fact that this system is currently not operational and SNCR is being used to meet the NOx limit for this facility. In other words, over the long-term, the Solnhofen SCR system has not preformed better than the SNCR system and, as of this writing, it has been shutdown.

The Solnhofen SCR system did operate over a period of several years, but as described above, its long-term, demonstrated control effectiveness was not measurably different than the expected control effectiveness of SNCR (on the order of 30 to 40% based on publicly available data). In addition, there are a number of significant differences between the Solnhofen application and the Alpena kilns including:

- Kiln design;
- Flue gas sulfur levels; and
- Particulate mass loadings and compositions.

For the above reasons, the European cement plant experience with SCR systems does not meet the test of being "demonstrated in practice".

There are a number of issues that must be considered in evaluating the potential application of SCR to the kilns at Alpena. First, as with SNCR, temperature is a critical variable in application of SCR technology to any source. In the case of the Alpena kilns, there is no location in the gas path where SCR could be applied. Second is the long-term viability of SCR technology in cement kiln applications. There are no known applications of SCR to long dry cement kilns like those at Alpena.

It has been theorized that an SCR system could be installed downstream of the dust collection equipment on long dry kilns. Such an application would involve additional fuel combustion to reheat the gas and then the use of heat recovery equipment to limit the additional fuel used. This type of SCR installation has not been tested or demonstrated on a cement kiln (i.e., it has not been "demonstrated in practice") and it presents a

[11] See for example: "Response to Comments, Permit No. 2000-05-077"; Submitted to Missouri Department

number of potential problems including the issue of fine particulate emissions generated by the SCR system itself, the potential for significant production of sulfuric acid mist in SCR system, and the potential for rapid catalyst deactivation due to the fine particulate in the effluent gas. The only U.S. applications of SCR in a low-dust environment using heat recovery of the SCR effluent to preheat the SCR inlet stream are on very low sulfur applications (i.e., less than 10 ppm SO_2). Any attempt to apply this type of system to the Alpena kilns would be experimental in nature and such experimental technologies are not considered "available" when it comes to determining BART (as this term is described in the BART rule).

Step 2 - Eliminate Technically Infeasible Control Options

Of the NOx control options identified in this BART analysis, low-NOx burners and SNCR are feasible options for application to the Alpena kilns.

The application of SCR to the Alpena kilns represents a technology experiment that would require significant time, resources, and risk. The BART process is intended to apply "available" technologies to existing facilities. Thus, SCR is not considered "available" as its application would require significant development and testing before the suitability for application to the Alpena kilns could even be determined.

Step 3 - Rank Feasible NOx Control Options

The most effective, technically feasible NOx control option for the Alpena kilns is the application of low-NOx burners and SNCR in combination. Lafarge estimates that this combination of technologies can achieve 35% NOx reduction on KG5 and 40% reduction on KG6.

Step 4 – Evaluate Feasible Control Options

The results of the visibility impact analysis performed for the Lafarge Alpena kilns show that both SO_2 and NOx impacts on visibility are similar when compared on a mass

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of Natural Resources by: Holcim (US) Inc.; April 8, 2004.

emissions basis (i.e., SO_2 and NOx reductions both result in similar visibility improvements per ton of emissions reduction). For this reason, Lafarge has evaluated the effectiveness, costs, and energy and environmental impacts of the technically feasible SO_2 and NOx control technologies identified in this BART analysis together and used this assessment to select BART based on a combination of SO_2 and NOx controls.

3.3 SO_2 and NOx Control Cost Comparision

Table 3-1 summarizes the results of Lafarge's evaluation of the costs of SO_2 and NOx control technologies determined to be technically feasible for retrofit to the Alpena kilns. Note that the energy impacts and secondary environmental impacts of these technologies are judged to be modest. Wet FGD will increase demand for electrical energy to operate pumps and fans in the FGD system. The FGD system will generally be closed loop with respect to water, so wastewater production will be minimal. Fresh water demand for this system can be readily met using existing plant water systems. Duct injection may result in a small increase in power demand and a small increase in the amount of CKD that must be disposed of. SNCR will result in an increase in NH_3 emissions which can cause formation of fine particulates through reaction with SO_3 and/or HCl in the exhaust gases from the kiln. None of these impacts are judged to be significant relative to the benefits of the control technologies evaluated.

Table 3-1. Comparison of Costs for Feasible BART Controls

Control Option	Control Costs ($/ton)*	
	KG5	KG6
Wet FGD	$7,952	$1,087
Duct Injection	$3,367	$754
SNCR	$713	$498

* See Appendix B for details of how these costs were estimated.

As shown in Table 3-1, certain of the estimated control costs appear reasonable and certain costs are excessive. In particular, the costs of both duct injection and wet FGD applied to KG5 at approximately $3,400 and $8,000 per ton, are excessive. This determination is made relative to the costs of the other control options listed in Table 3-1, relative to the costs/value of incremental SO_2 control under the acid rain program, and relative to past SO_2 BACT determinations in the Midwest. For example, the current value of SO_2 allowances available for purchase (and potential retirement) under U.S. EPA's acid rain program (i.e., Title IV of the 1990 Clean Air Act amendments) is less than $500/ton.[12] The reason SO_2 control costs for KG5 are excessive is because of the low SO_2 emissions rate from these kilns relative to the volume of exhaust gases produced. KG6 represents a much more cost-effective location to achieve significant SO_2 reductions at the Alpena plant.

In addition, as discussed in Section 5, addition of SO_2 controls on KG5 result in minimal improvement in visibility. The addition of SO_2 controls on KG5 results in only two fewer days in a three year period with a visibility impact at Seney in excess of the 0.5 dv criterion.

Based on this assessment, Lafarge concludes that the BART limit for the Alpena plant should based on the implementation of the SNCR on KG5 and KG6 and the implementation of wet FGD on KG6. Implementation of additional controls results in substantial added costs with only limited visibility improvement (as measured by the total emissions reductions achieved). The specific visibility impacts of the proposed BART controls are evaluated and discussed in Section 5.

3.4 Proposed BART

Lafarge proposes to install SNCR on all kilns (KG5 and KG6) and wet scrubbers on the kilns in KG6. Consistent with this control plan, Lafarge is proposing a facility-wide BART limit on all five kilns of 29.4 tons of NOx per day and 53.1 tons of SO_2 per day.

[12] CantorCO2e Real Time Market Data; Spot SO2 Market Summary; March 13, 2007.

Lafarge proposes that these limits be expressed as a 30-day rolling average. These proposed limits are based on applying the BART technology control efficiencies outlined in Sections 3.1 and 3.2 to the maximum daily emission rates measured during the 2002-2004 period for each kiln. Specifically, the baseline, actual maximum emissions from the two kiln groups were determined to be:

Compound	Baseline Maximum Emissions (tons/day)	
	KG5	KG6
SO_2	38.1	78.7
NOx	18.9	28.5

Table 1-1 summarizes the proposed BART technologies and emission limits in more detail. Lafarge is proposing mass emission limits for NOx and SO_2 that apply to the total emissions from the BART-affected emission units (i.e., Kilns 19-23). Lafarge will employ continuous emission monitors to record mass emissions on a daily basis to insure compliance.

4.0 BART MODEL PROCEDURE

4.1 Modeled Emissions and Stack Parameters

Maximum, 24-hour actual emission rates during normal operation for 2002-2004 were determined and modeled in CALPUFF to calculate baseline visibility impacts at Seney. Baseline NOx and SO_2 emissions from the kilns were obtained from continuous emission monitors (CEMS) during the 2002-2004 period. Particulate emissions were based upon stack test data. All PM_{10} emission were assumed to be filterable and were speciated, using VISTAS provided speciation profiles for dry process cement kilns, into PM_{10} (PMC or PM Coarse), $PM_{2.5}$ (PMF or PM Fine), and elemental carbon (EC). As recommended by VISTAS, the condensable PM_{10} fraction was assumed to be 85.6% of the total PM_{10} emissions rate. The total PM_{10} rate was calculated from the filterable fraction assuming that the filterable fraction is 14.4% of the total. The condensable fraction was then speciated (again using the VISTAS recommended speciation profiles) into sulfates and secondary organic aerosols (SOA). The PM speciation calculations are presented in Appendix A.

Based upon guidance from the Michigan Department of Environmental Quality (MDEQ), Lafarge modeled emissions of PM_{10}, NOx and SO_2 in calculating baseline visibility impacts at Seney. Lafarge did not model emissions of volatile organic compounds (VOCs) or ammonia as these pollutants are not believed to contribute significantly to visibility degradation at Seney. Only emissions of NOx and SO_2 were varied in evaluating the affects of the various control technologies on visibility improvement. Lafarge did not evaluate PM control alternatives because the kilns are subject to a MACT standard which limits emissions of PM and, according to the final BART Guidelines, states may assume that the level of control required by a MACT standard meets BART (see 70 FR 39164). The stack parameters and emission rates that were modeled are provided in Tables 4-1 and 4-2, respectively.

Table 4-1. Modeled Stack Parameter Data

Model Source ID	Source Description	LCC E (km)[a]	LCC N (km)[a]	Stack Height (m)	Base Elevation (m)	Stack Diameter (m)	Exit Velocity (m/sec)	Temp. (K)	Sigma Y (m)	Sigma Z (m)	Momentum Flux
SV00031	K19 Exhaust	1066.746	641.668	67.06	182.0	3.96	3.91	439.26	0	0	1
SV00032	K20 Exhaust	1066.762	641.671	67.06	182.0	3.96	3.91	439.26	0	0	1
SV00033	K21 Exhaust	1066.780	641.675	67.06	182.0	3.96	6.03	439.26	0	0	1
SV00047	K22-23 Exhaust	1066.867	641.697	89.00	182.0	7.32	6.73	469.82	0	0	1
KILNS	Worst –Case Combined	1066.789	641.678	81.37	182.00	6.15	5.97	459.19	0	0	1

[a]Lambert Conformal Conic (LCC) coordinates are based upon an origin of 40.0N and 97.0W with Standard Parallels of 33.0N and 45.0N (WGS-84 Datum).

Table 4-2. Baseline Modeled Emission Rates (lb/day)

Model Source ID	Source Description	SO_2	SO_4	NOx	HNO_3	NO_3	PMC	PMF	EC	SOA
SV00031	K19 Exhaust	34,760	577	13,116	0	0	51	54	6	79
SV00032	K20 Exhaust	19,656	577	12,712	0	0	51	54	6	79
SV00033	K21 Exhaust	21,796	577	11,942	0	0	51	54	6	79
SV00047	K22-23 Exhaust	157,398	2,768	56,956	0	0	245	257	26	377
KILNS	Worst –Case Combined	233,610	4,498	94,726	0	0	399	417	43	613

Notes: PMFine (PMF) or "soil" = PM < 2.5 um in diameter. PMCoarse (PMC) = PM between 2.5 and 10 um in diameter. SOA = secondary organic aerosols. EC = elemental carbon. Kiln PM speciation based upon VISTAS guidance.

To simplify the modeling analysis, Lafarge modeled a single, worst-case stack. The emissions from each kiln were summed and assumed to be emitted from the worst-case stack. The parameters for the worst-case stack were calculated as a weighed sum with total emissions as the basis for the weighting. Appendix A provides the values used in calculating the worst-case parameters. The worst-case stack parameters were assumed not to be affected by the controls employed. That is, only stack gas emissions were varied in evaluating BART control alternatives. Stack gas exit temperature and flow as well as the physical parameters (i.e., diameter and height) were held constant in the control technology evaluation.

The post-control emission rates for each of the BART control scenarios evaluated were based upon the anticipated reduction from each control device (expressed as a percentage) and the baseline rates. The post-control emission rates for each modeled BART scenario are presented in Table 4-3.

4.2 Modeling Methodology

The modeling followed EPA's Interagency Workgroup on Air Quality Modeling (IWAQM), Phase 2 recommendations, for long-range transport[13] and the Lake Michigan Air Director's Consortium (LADCO) Single Source Modeling Guidance.[14] The IWAQM guidance was developed to address air quality impacts—as assessed through the Prevention of Significant Deterioration permitting program. The LADCO guidance was developed specifically for BART modeling.

[13] Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts, EPA-454/R-98-019, U.S. Environmental Protection Agency, Air Quality Modeling Group, Research Triangle Park, North Carolina. December, 1998.
[14] Single Source Modeling to Support Regional Haze BART Modeling Protocol, Lake Michigan Air Directors Consortium, Des Plaines, IL. March 21, 2006.

Table 4-3. Post-Control Modeled Emission Rates (lb/day)

Source Description	SO_2	SO_4	NOx	HNO_3	NO_3	PMC	PMF	EC	SOA
Control Scenario 1: SNCR KG5 & 6, Wet Scrubbing KG6 (Proposed BART)									
KG5	76,212	1,730	24,551	0	0	153	161	17	236
KG6	31,480	1,384	34,174	0	0	245	257	26	377
Total	107,692	3,114	58,724	0	0	399	417	43	613
Reduction from Baseline (%)	54	31	38	0	0	0	0	0	0
Control Scenario 2: SNCR KG5 & 6, Wet Scrubbing KG6, Duct Injection KG5									
KG5	60,970	1,557	24,551	0	0	153	161	17	236
KG6	31,480	1,384	34,174	0	0	245	257	26	377
Total	92,449	2,941	58,724	0	0	399	417	43	613
Reduction from Baseline (%)	60	35	38	0	0	0	0	0	0
Control Scenario 3: SNCR KG5 & 6, Wet Scrubbing KG5 & 6									
KG5	15,242	865	24,551	0	0	153	161	17	236
KG6	31,480	1,384	34,174	0	0	245	257	26	377
Total	46,722	2,249	58,724	0	0	399	417	43	613
Reduction from Baseline (%)	80	50	38	0	0	0	0	0	0

Note: KG5 = Kiln Group 5 which consists of Kilns 19-21. KG6 = Kiln Group 6 which consists of Kilns 22 & 23.

4.3 CALMET

Meteorological Domain

The Meteorological Domain was set to one hundred kilometers beyond all sources and receptors (see Figure 4-1). This Domain was cast on a Lambert Conformal Conic (LCC) coordinate system. The projection parameters and Meteorological Domain coordinates are as follows:

LCC Projection Parameters	
Projection Origin –	RLAT0 = 40N, RLON0 = 97W
False Easting –	FEAST = 0
False Northing –	FNORTH = 0
Matching Parallels -	XLAT1 =33N, XLAT2 = 45N
Meteorological Domain	
Datum -	WGS-84
Southwest corner (km) -	XORIGKM = 725.1340, YORIGKM = 541.6970
Number of Grid Cells -	NX = 110, NY = 78
Horizontal Grid Spacing (km) -	DGRIDKM = 4
Vertical Grid Spacing (km) – (top of each cell)	20, 40, 80, 160, 320, 1000, 1500, 2200, 3000

Meteorological Data

Prognostic data for 2002, 2003 and 2004 was used for developing the Initial Guess Wind Fields in the CALMET model. The prognostic data was supplied by LADCO. These data cover an area from the eastern seaboard to the Rocky Mountains and from the Gulf of Mexico to well into Canada.

Surface data for 2002, 2003 and 2004 was used as observations in developing the Step 2 Wind Fields in the CALMET model. The surface data were purchased from BEE-Line Software, Asheville, NC. BEE-Line Software obtained these data from the National Climatic Data Center, Asheville, NC. The data includes all stations, with sufficient data for modeling, within or near the meteorological modeling domain. A total of eleven stations were used.

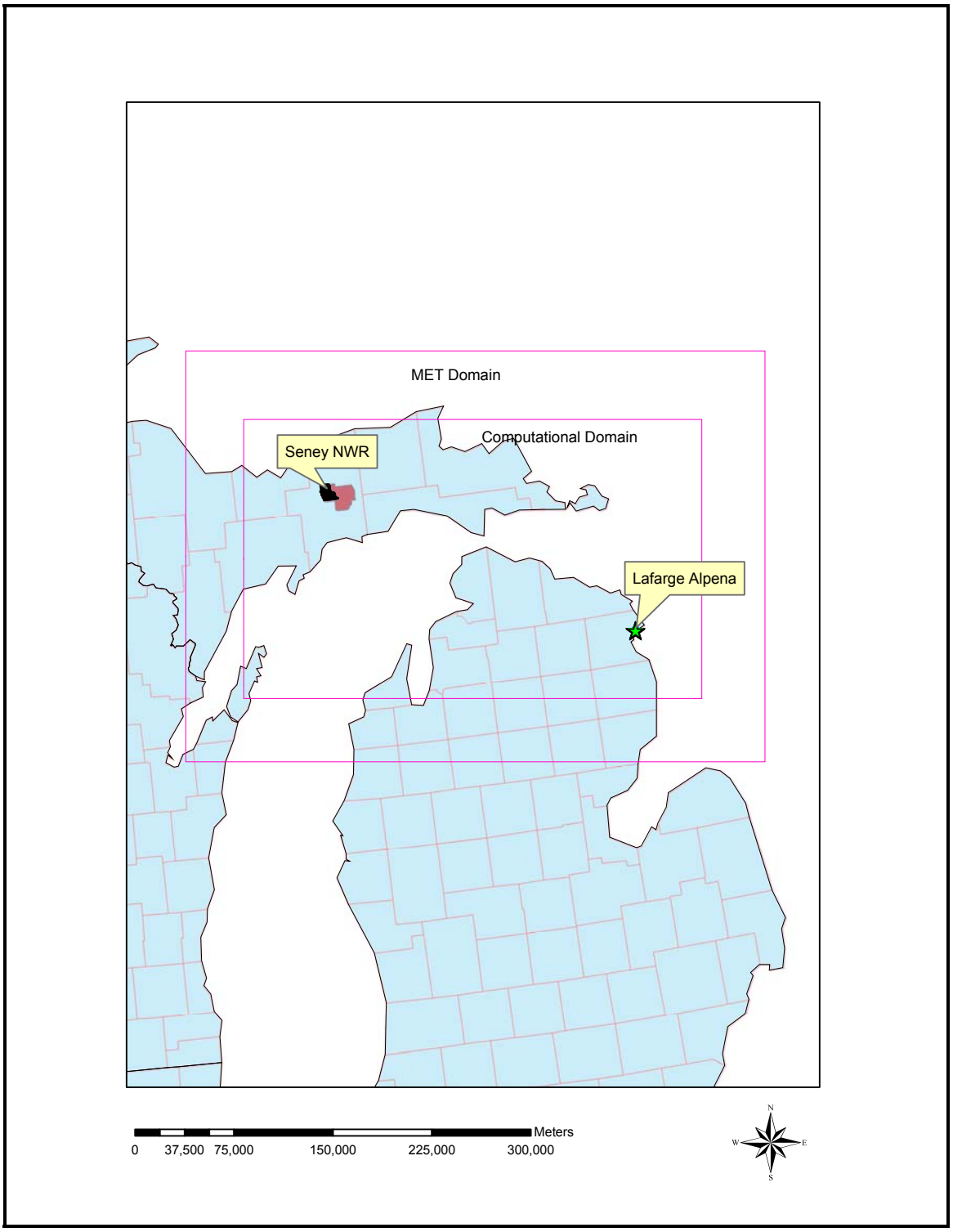

Figure 4-1. Lafarge Meteorological and Computational Domain

Upper air data for 2002, 2003 and 2004 were used as observations in developing the Step 2 Wind Fields in the CALMET model. The upper air data were purchased from BEE-Line Software, Asheville, NC. BEE-Line Software obtained these data from the NOAA Forecast Systems Laboratory web site. Two upper air stations, Gaylord and Green Bay, were found to be located near or in the meteorological modeling domain.

Precipitation data for 2002, 2003 and 2004 were used as observations in developing the Step 2 Wind Fields in the CALMET model. The precipitation data were purchased from BEE-Line Software, Asheville, NC. BEE-Line Software obtained these data from the National Climatic Data Center, Asheville, NC. The dataset includes all stations, with sufficient data for modeling, within or near the meteorological modeling domain. A total of 19 stations were used for 2002 and 21 stations were used for 2003 and 2004.

A list of all the surface, upper air, and precipitation stations that were used in the analysis are presented in Appendix C.

Geophysical Data

Land Use data were used to develop the surface characteristic for input to the CALMET model. For the US portion of the modeling domain, the best large-scale land use data sets are the USGS National Land Cover Dataset (NLCD 92) which have a 30 meter resolution. These data were used for the US portion of the modeling domain. The NLCD data is not available outside of the US. For the Canadian portion of the modeling domain, the USGS EROS Global Land Cover Characterization (GLCC Version 2) were used.

Terrain data is used by the CALMET model to modify the Initial Guess Wind Fields in developing the Step 1 Wind Fields. For the US portion of the modeling domain, USGS 1:250,000 scale Digital Elevation Model (DEM) data were used. For the Canadian portion of the modeling domain, the USGS GTOPO30 data were used.

CALMET Preprocessing

The SMERGE program reads multiple surface data files that may be in several different formats and makes any needed units conversion and writes the combined data to a single file (surf.dat). The surf.dat file is read by CALMET as observations and is used in the modification of the Step 1 Wind Fields in developing the Step 2 Wind Fields.

The READ62 program reads an upper air data file and extracts soundings, makes any needed units conversion and writes the data to a processed data file. READ62 is repeated for each upper air file. Most upper air data files contain missing data and other errors. These missing data are filled and the errors are corrected. These changes are documented in the upper air list (.lst) files. The processed data files are read by CALMET as observations and are used in the modification of the Step 1 Wind Fields in developing the Step 2 Wind Fields.

PXTRACT and PMERGE extract data for specific stations and combine the data into a single processed data file. The processed data file is read by CALMET as observations and are used in the modification of the Step 1 Wind Fields in developing the Step 2 Wind Fields.

CTGPROC reads land use data and calculates weighted land use for each grid cell in the modeling domain and writes a processed data file.

TERREL reads terrain data and calculates the elevation of the center of each grid cell in the modeling domain and writes a processed data file.

MAKEGEO reads the processed data files from CTGPROC and TERREL. MAKEGEO calculates weighted surface characteristics and writes these along with the terrain elevations to a processed data file. The processed data file is used by the CALMET model to modify the Initial Guess Wind Fields in developing the Step 1 Wind Fields.

CALMET Analysis

The CALMET analysis followed guidance of IWAQM[15] and FLAG[16]. Version 6.211 of the CALMET model was used to develop the parameters for the three-dimensional Meteorological Grid. The Meteorological Grid includes meteorological parameters, surface parameters and terrain elevations for each hour. This three-dimensional Meteorological Grid was calculated by CALMET in three steps as follows.

Initial Guess Wind Fields. The 36 km prognostic data for 2002, 2003 and 2004 was used for developing the Initial Guess Wind Fields of the 4 km three-dimensional Meteorological Grid.

Step 1 Wind Fields. The terrain and surface parameters are used to modify the Initial Guess Wind Fields to develop the Step 1 Wind Fields of the 4 km three-dimensional Meteorological Grid. The area that most influences the transport and dispersion of puffs from the source to the Class I Area is the area near a line from the source to the Class I Area. This area is generally gently sloping or overwater. Just to the south of this line in the north-central part of the lower part of Michigan are two higher areas with a shallow valley between. The higher terrain to the south is a little over 400 meters AMS, the valley floor is about 200 meters AMS, and north of the valley the terrain raises to an elevation of about 320 meters AMS. The distance from high terrain to high terrain is about 50 kilometers. Therefore, the radius of influence of terrain features (TERRAD) was set to 25 km to account for this terrain. The slope of the intervening terrain is gentle and the value of TERRAD should have very little influence on the calculated impacts.

Step 2 Wind Fields. Meteorological observations (surface data, upper air data and precipitation data) are used to modify the Step 1 Wind Fields to develop the Step 2

[15] Interagency Workgroup on Air Quality Modeling Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts (EPA-454/R-98-019) (IWAQM)

[16] Federal Land Managers Air Quality Related Values Work Group Phase I report (USFS, NPS, USFWS, 2000) (FLAG)

Wind Fields of the 4 km three-dimensional Meteorological Grid. The terrain is gently rolling in the area that most influences the transport and dispersion of puffs from the source to the Class I Area. Therefore, the radius of influence of the observations should be relatively large. The maximum distances and relative weightings of observations were set as follows.

Maximum Over Land Surface (KM) –	RMAX1 = 100
Maximum Over Land Aloft (KM) -	RMAX2 = 200
Maximum Over Water (KM) -	RMAX3 = 100
Relative Weighting Surface (KM) -	R1 = 30
Relative Weighting Aloft (KM) -	R2 = 60

4.4 CALPUFF

Output from the CALMET model was input to the CALPUFF model, which simulates the effects of the meteorological conditions on the transport and dispersion of pollutants from an individual source. Version 6.112 of CALPUFF was used in the analysis.

Modeling Domain

The CALPUFF modeling domain was designed to include the Lafarge facility and the Seney Class I area (this is the only Class I Area within 500 km of Lafarge). A 50 km buffer zone in each direction was included in establishing the computational modeling domain. The domain dimensions are therefore 440 km east-west by 312 km north-south. The modeling (computational) domain is shown in Figure 3. Ninety eight grid cells were employed in the east-west axis and 65 in the north-south axis.

Class I Area Receptors

Lafarge used the FLM Class I receptors for Seney, with elevations, as obtained from the National Parks Service. The receptor coordinates and elevations are provided in Appendix D.

Control File Settings

In general, Lafarge used the default options in the CALPUFF model.[17] The deviations from the default values are discussed below.

- The MESOPUFF II module was used for chemical transformation (MCHEM=1)
- Number of vertical layers (NZ) was set to 10 and cell face heights (ZFACE) of 0, 20, 40, 80, 160, 320, 1000, 1500, 2200, and 3000 meters were used (to be consistent with CALMET runs).
- The integrated puff sampling methodology was used for puff recognition.
- Building downwash was ignored because the Class Area is located greater than 50 km from the source and downwash should not influence concentration estimates.

Ozone and Ammonia Background Values

CALPUFF uses background ozone (O_3) and ammonia (NH_3) values in its chemistry module. Per LADCO Guidance, Lafarge used the domain seasonal average ozone and ammonia concentration values provided in the LADCO BART Guidance document.

4.5 CALPOST

Calculation Methods for Background Light Extinction

Input required by CALPOST includes an input control file and the hourly concentration output file from CALPUFF. The primary settings for the CALPOST control file are associated with the method for calculation of light extinction. The CALPOST control file was set such that the background light extinction calculation Visibility Method 6 (MVISBK=6) was used. This is the default value as described in LADCO's protocol document. As required by Method 6, The EPA Class I area-specific (centroid) monthly relative humidity values for the Seney Class I area were used. These values were obtained from Table A-3 of the EPA's "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule".[18]

[17] As defined by pages B-2 through B-8 of the IWAQM Phase 2 Summary Report.
[18] "Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule", EPA-450/B-03-005, September 2003.

In Visibility Method 6, CALPOST also requires monthly background concentrations of ammonium sulfate, ammonium nitrate, coarse particulate mass, organic carbon, soil, and elemental carbon. Annual averages reflective of natural background conditions for these species were obtained from the EPA's "Guidance for Natural Visibility" document.

Light Extinction Efficiencies and Rayleigh Scattering Value

The other values required to execute CALPOST include the light extinction efficiencies for the pollutant species identified above (i.e., ammonium sulfate, ammonium nitrate, etc.) and the extinction due to Rayleigh scattering (BEXTRAY). Dry extinction efficiencies for the pollutant species were set equal to the Table 2-1 values of the EPA Visibility Guidance Document. The value for Rayleigh scattering was set to 10 Mm^{-1}.

5.0 BART MODEL RESULTS

The CALPUFF modeling system was executed with input data and settings as described in Section 4. Delta-deciview results were obtained from the "24HR VISIBILITY (deciview)" table in the CALPOST output files. The regional haze regulation and BART guideline stipulate that the States have flexibility in determining the degree of visibility improvement that should be considered acceptable in assessing appropriate BART controls (see 70 FR 39170). The States may consider the frequency, magnitude, and duration components of visibility impairment. EPA suggests that the States use a comparison threshold, as is done for determining if BART-eligible emission units are subject to BART. Alternatively, States may compare the 98th percent days for the pre- and post-control runs. The MDEQ has requested that Lafarge provide the 98th percentile values as well as the number of days with delta deciview values in excess of the 0.5 BART-eligibility criterion for both the pre- and post-control scenarios. These results are presented in Table 5-1 as well as Appendix E.

As shown in Table 5-1, both the 98th percentile deciview value and the number of days in excess of 0.5 deciviews decrease with each of the control scenarios evaluated. However, the majority of the reduction is realized between the baseline and the control scenario no. 1 (SNCR on all kilns and wet scrubbing on KG6). The next highest level of control (adding duct injection to KG5) results in some degree of visibility improvement. However, the costs of the additional level of control outweighs the small additional improvement in modeled visibility impacts. The addition of duct injection on KG5 would only improve the combined, three year 98% dv value by 0.05 dv (0.746-0.697 dv) at a cost of over $3,300/ton or approximately $2,800,000/dv [$1,702,833/1.301-0.6967 dv]. The next level of control (addition of wet scrubbers to KG5) is even more expensive at $7,952/ton or approximately $21,000,000/dv [$16,287,149/(1.301-.509)].

The CALPUFF and CALPOST input and output files are provided on the enclosed CD.

Table 5-1. Delta Deciview Visibility Impact Rankings (4km CALMET Grid, Annual Average Concentrations as Background)

Scenario	2002		2003		2004		2002-2004 Combined	
	98th Percentile Value	No. Days 98% > 0.5 deciview	98th Percentile Value	No. Days 98% > 0.5 deciview	98th Percentile Value	No. Days 98% > 0.5 deciview	98th Percentile Value	No. Days 98% > 0.5 deciview
Baseline	0.711	3	1.852	15	1.089	7	1.301	25
Control Scenario 1: SNCR KG5&6, Wet Scrubbing KG6 (Proposed BART)	0.371	0	1.022	10	0.641	3	0.746	12
Control Scenario 2: SNCR KG5&6, Wet Scrubbing KG6, Duct Injection KG5	0.340	0	0.908	10	0.614	3	0.697	10
Control Scenario 3: SNCR KG5&6, Wet Scrubbing KG5&6	0.242	0	0.644	6	0.474	0	0.509	1

APPENDIX A

PM_{10} Speciation, Emission Calculations, And Worst Case-Stack Parameter Determination

PM_{10} Emissions from Lafarge Alpena Kilns

Source Equipment Number	New MAERS Activity ID No.	Model Source ID	Source Description	Material	Maximum Feed Rate (ton/hr)	Potential Emission Factor (lb/ton feed)	Emission Factor Reference	PM PTE (lbs/hr)	PM_{10} PTE (lbs/hr)	PM_{10} PTE (ton/yr)
25-253	KILN 19	SV00031	K19 Exhaust	Kilns (CKD)	90	0.06	MAERS, Test	5.40	4.59	20.1
25-265	KILN 20	SV00032	K20 Exhaust	Kilns (CKD)	90	0.06	MAERS, Test	5.40	4.59	20.1
25-266	KILN 21	SV00033	K21 Exhaust	Kilns (CKD)	90	0.06	MAERS, Test	5.40	4.59	20.1
26-256	KILN 22	SV00047	K22-23 Exhaust	Kilns (CKD)	144	0.11	MAERS, Test	15.84	13.46	59.0
26-256	KILN 23	SV00047	K22-23 Exhaust	Kilns (CKD)	144	0.07	MAERS, Test	10.08	8.57	37.5

Maximum hourly feed rates based upon a clinker factor of 1.8 and the following maximum clinker rates: K19-K21:50 ton/hr each, K22-K23-80 ton/hr each.

PM Speciation

	Uncontrolled PM10 Emissions (**Bold** Value is **Input** by user.)																	
Kiln	Total PM10		Filterable	Coarse - PMC	Ext.	Fine	Fine Soil - PMF	Ext.	Fine EC	Ext.		Condensible	CPM IOR -SO4	Particle		CPM OR - SOA	Particle	
Lafarge Kiln	(lb/hr)		(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.		(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
KILN 19	31.9		**4.6**	2.1	0.6	2.5	2.2	1	0.2	10		27.3	24.0	SO4	3	3.3	SOA	4
KILN 20	31.9		**4.6**	2.1	0.6	2.5	2.2	1	0.2	10		27.3	24.0	SO4	3	3.3	SOA	4
KILN 21	31.9		**4.6**	2.1	0.6	2.5	2.2	1	0.2	10		27.3	24.0	SO4	3	3.3	SOA	4
KILN 22	93.6		**13.5**	6.3	0.6	7.2	6.5	1	0.7	10		80.1	70.5	SO4	3	9.6	SOA	4
KILN 22	59.5		**8.6**	4.0	0.6	4.6	4.2	1	0.4	10		51.0	44.9	SO4	3	6.1	SOA	4

Worst-Case Stack Parameter Determination - Weighting Based Upon Emissions

Model Source Description	Model Source ID	Sum of Emissions (lb/hr)	Weighting Factor Based on Emissions	Weighted Stack Height (m)	Weighted Base Elevation (m)	Weighted Stack Diameter (m)	Weighted Exit Velocity (m/sec)	Weighted Temp. (K)
K19 Exhaust	SV00031	2027	0.15	9.76	26.48	0.58	0.57	63.91
K20 Exhaust	SV00032	1381	0.10	6.65	18.04	0.39	0.39	43.54
K21 Exhaust	SV00033	1438	0.10	6.92	18.78	0.41	0.62	45.34
K22-23 Exhaust	SV00047	9085	0.65	58.05	118.70	4.77	4.39	306.41
Combined	KILNS	13929	1	**81.37**	**182.00**	**6.15**	**5.97**	**459.19**

APPENDIX B

Control Costing Calculations and Supporting Documentation

KG5 Wet Scrubber Cost Estimate

Item	Basis	Value	Comments
		Capital Cost Estimate	
Purchased equipment Costs			
Scrubber System Cost (SSC)	Vendor Quote + Plant Estimates	43,200,000	Includes scrubber, reagent prep, piping, tanks, and pumps, air compressors, gypsum handling, fans, and duct work.
Instrumentation	= 0.05*SSC	2,160,000	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995) - use 1/2 value to account for instrumentation in scrubber price.
Sales taxes	= 0.03*SSC	1,296,000	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Freight	= 0.05*SSC	2,160,000	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Purchased equipment cost (PEC)	PEC = 1.13*SSC	48,816,000	= Scrubber System Cost (SSC) + Instrumentation + Sales taxes + Freight
Direct installation costs			
Foundations & supports	Included in PEC	-	Included in SSC
Handling & erection	Included in PEC	-	Included in SSC
Electrical	Included in PEC	-	Included in SSC
Piping	Included in PEC	-	Included in SSC
Insulation	Included in PEC	-	Included in SSC
Painting	Included in PEC	-	Included in SSC
Direct installation costs	Included in PEC	-	Included in SSC
Site preparation & Buildings (SP + BLD.)	As required	9,000,000	Lafarage Estimate: includes roads, electrical, water, etc.
Total Direct Costs (DC)	= PEC + SP +BLD.	57,816,000	= Site preparation & Buildings (SP + BLD.) + Purchased equipment cost (PEC)
Indirect Costs (installation)			
Engineering	= 0.10*PEC	4,881,600	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Construction and field expenses	= 0.10*PEC	4,881,600	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Contractor fees	= 0.10*PEC	4,881,600	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Start-up	= 0.01*PEC	488,160	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Performance test	= 0.01*PEC	488,160	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Contingencies	= 0.25*PEC	9,763,200	Conservative estimate of contingency based on level of engineering.
Lost Production During Retrofit	30 days of downtime/kiln	4,320,000	Based on lost production of $40/ton and a capacity of 150 tph.
Total Indirect Costs (IC)	= 0.35*PEC	29,704,320	= SUM of Indirect Cost Elements
Total Capital Investment $ (TCI)	= IC+ DC	91,840,320	= Total Direct Costs (DC) + Total Indirect Costs (IC)

Annualized Cost Estimate			
Annual Cost Inputs			
Reagent Ratio (moles limestone/mole SO2 removed)	Estimate.	1.1	1.05 Reagent Ratio & 95% CaCO3 in limestone.
Operating Labor Cost ($/hr)	Lafarge Data; unburdened cost.	23.78	Lafarge Data
Supervisory Labor Cost ($/hr)	Lafarge Data; unburdened cost.	31.58	Lafarge Data
Maintenance Labor Cost ($/hr)	Lafarge Data; unburdened cost.	24.78	Lafarge Data
Power Cost ($/kW)	Lafarge Data	0.063	Lafarge Data
Limestone Cost ($/ton)	Lafarge Data	1.25	Lafarge Data
Water Cost ($/1000 gal)	Lafarge Data	4.9	Lafarge Data
SO2 to Scrubber (tpy)	Based on 2004/2005 Average Emissions.	2,529	
SO2 Removal Efficiency (%)	Design Estimate.	90%	
FGD On-stream Time (%)	Design Estimate.	90%	
SO2 Removed by Scrubber (tpy)	Calculated from above values.	2,048	= SO2 to Scrubber (tpy) * SO2 Removal Efficiency (%) * FGD On-stream Time (%)
Gypsum MW (lb/lb-mole)	Constant	172	
CaCO3 MW (lb/lb-mole)	Constant	100	
SO2 MW (lb/lb-mole)	Constant	64	
Gypsum Production Rate (tpy -dry basis)	CaSO4*2H2O (dry basis)	5,504	= SO2 Removed by Scrubber (tpy) * Gypsum MW (lb/lb-mole) / SO2 MW (lb/lb-mole)
Gypsum Value ($/ton - dry basis)	Lafarge Data	16	Lafarge Data
Water Evaporation Rate (gpm)	Estimate.	100	
Direct Annual Costs (DAC)			
Operating labor			
• Operator ($/yr)	3.0 operators per shift	624,938	Estimate of staffing based on scrubber complexity.
• Supervisor ($/yr)	15% of operator labor	124,488	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Operating materials			
• Water ($/yr)	10 wt. % free moisture in Gypsum + evap.	233,790	Based on evaporation, and water lost w/ gypsum.
• Limestone ($/yr)	Based on Reagent Ratio of 1.1.	4,400	Calculated based on Reagent Ratio & SO2 removal rate.
• Wastewater disposal ($/yr)	None (FGD is assumed zero discharge)	0	Zero discharge.
Maintenance			
• Labor ($/yr)	1.0 person per shift	217,073	Estimate of staffing based on scrubber complexity.
• Material ($/yr)	100% of maintenance labor	217,073	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Electricity			
• Fans ($/yr)	400 kW for scrubber fans.	198,677	Design estimate.
• Pumps ($/yr)	120 kW for scrubber pumps.	59,603	Design estimate.
• Air Compressors ($/yr)	20 kW for oxidation air compressor.	9,934	Design estimate.
• Limestone Grinding System ($/yr)	150 kW for limestone grinding circuit.	74,504	Design estimate.
Gypsum Credit ($/yr)	Gypsum value as cement additive.	-88,069	= -Gypsum Production Rate (tpy -dry basis) * Gypsum Value ($/ton - dry basis)
DAC Subtotal	Direct Annual Costs (DAC)	1,676,411	= SUM of Direct Annual Cost Items
Indirect Annual Costs (IAC)			
Overhead ($/yr)	60% of total labor and material costs	853,058	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Administrative charges ($/yr)	2% of Total Capital Investment	1,836,806	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Property tax ($/yr)	1% of Total Capital Investment	918,403	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Insurance ($/yr)	1% of Total Capital Investment	918,403	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Capital recovery ($/yr)	10.98% x Total Capital Investment	10,084,067	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
IAC Subtotal	Indirect Annual Costs (IAC)	14,610,738	= SUM of Indirect Annual Cost Items
Annualized Costs			
Total Annual Cost ($/yr)	DAC + IAC	16,287,149	= IAC Subtotal + DAC Subtotal
Control Cost Effectiveness ($/ton)	TAC / Tons SO2 Removed	7,952	= Total Annual Cost ($/yr) / SO2 Removed by Scrubber (tpy)

KG6 Wet Scrubber Cost Estimate

Item	*Basis*	*Value*	*Comments*
		Capital Cost Estimate	
Purchased equipment Costs			
Scrubber System Cost (SSC)	Vendor Quote + Plant Estimates	30,000,000	Includes scrubber, reagent prep, piping, tanks, and pumps, air compressors, gypsum handling, fans, and duct work.
Instrumentation	= 0.05*SSC	1,500,000	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995) - use 1/2 value to account for instrumentation in scrubber price.
Sales taxes	= 0.03*SSC	900,000	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Freight	= 0.05*SSC	1,500,000	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Purchased equipment cost (PEC)	PEC = 1.13*SSC	33,900,000	= Scrubber System Cost (SSC) + Instrumentation + Sales taxes + Freight
Direct installation costs			
Foundations & supports	Included in PEC	-	Included in SSC
Handling & erection	Included in PEC	-	Included in SSC
Electrical	Included in PEC	-	Included in SSC
Piping	Included in PEC	-	Included in SSC
Insulation	Included in PEC	-	Included in SSC
Painting	Included in PEC	-	Included in SSC
Direct installation costs	Included in PEC	-	Included in SSC
Site preparation & Buildings (SP + BLD.)	As required	7,000,000	Lafarage Estimate: includes roads, electrical, water, etc.
Total Direct Costs (DC)	= PEC + SP +BLD.	40,900,000	= Site preparation & Buildings (SP + BLD.) + Purchased equipment cost (PEC)
Indirect Costs (installation)			
Engineering	= 0.10*PEC	3,390,000	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Construction and field expenses	= 0.10*PEC	3,390,000	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Contractor fees	= 0.10*PEC	3,390,000	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Start-up	= 0.01*PEC	339,000	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Performance test	= 0.01*PEC	339,000	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Contingencies	= 0.25*PEC	6,780,000	Conservative estimate of contingency based on level of engineering.
Lost Production During Retrofit	30 days of downtime/kiln	4,608,000	Based on lost production of $40/ton and a capacity of 160 tph.
Total Indirect Costs (IC)	= 0.35*PEC	22,236,000	= SUM of Indirect Cost Elements
Total Capital Investment $ (TCI)	= IC+ DC	63,136,000	= Total Direct Costs (DC) + Total Indirect Costs (IC)

Annualized Cost Estimate			
Annual Cost Inputs			
Reagent Ratio (moles limestone/mole SO2 removed)	Estimate.	1.1	1.05 Reagent Ratio & 95% CaCO3 in limestone.
Operating Labor Cost ($/hr)	Lafarge Data; unburdened cost.	23.78	Lafarge Data
Supervisory Labor Cost ($/hr)	Lafarge Data; unburdened cost.	31.58	Lafarge Data
Maintenance Labor Cost ($/hr)	Lafarge Data; unburdened cost.	24.78	Lafarge Data
Power Cost ($/kW)	Lafarge Data	0.063	Lafarge Data
Limestone Cost ($/ton)	Lafarge Data	1.25	Lafarge Data
Water Cost ($/1000 gal)	Lafarge Data	4.9	Lafarge Data
SO2 to Scrubber (tpy)	Based on 2004/2005 Average Emissions.	13,433	
SO2 Removal Efficiency (%)	Design Estimate.	90%	
FGD On-stream Time (%)	Design Estimate.	90%	
SO2 Removed by Scrubber (tpy)	Calculated from above values.	10,880	= SO2 to Scrubber (tpy) * SO2 Removal Efficiency (%) * FGD On-stream Time (%)
Gypsum MW (lb/lb-mole)	Constant	172	
CaCO3 MW (lb/lb-mole)	Constant	100	
SO2 MW (lb/lb-mole)	Constant	64	
Gypsum Production Rate (tpy -dry basis)	CaSO4*2H2O (dry basis)	29,241	= SO2 Removed by Scrubber (tpy) * Gypsum MW (lb/lb-mole) / SO2 MW (lb/lb-mole)
Gypsum Value ($/ton - dry basis)	Lafarge Data	16	Lafarge Data
Water Evaporation Rate (gpm)	Estimate.	100	
Direct Annual Costs (DAC)			
Operating labor			
• Operator ($/yr)	3.0 operators per shift	624,938	Estimate of staffing based on scrubber complexity.
• Supervisor ($/yr)	15% of operator labor	124,488	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Operating materials			
• Water ($/yr)	10 wt. % free moisture in Gypsum + evap.	242,417	Based on evaporation, and water lost w/ gypsum.
• Limestone ($/yr)	Based on Reagent Ratio of 1.1.	23,376	Calculated based on Reagent Ratio & SO2 removal rate.
• Wastewater disposal ($/yr)	None (FGD is assumed zero discharge)	0	Zero discharge.
Maintenance			
• Labor ($/yr)	1.0 person per shift	217,073	Estimate of staffing based on scrubber complexity.
• Material ($/yr)	100% of maintenance labor	217,073	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Electricity			
• Fans ($/yr)	500 kW for scrubber fans.	248,346	Design estimate.
• Pumps ($/yr)	300 kW for scrubber pumps.	149,008	Design estimate.
• Air Compressors ($/yr)	50 kW for oxidation air compressor.	24,835	Design estimate.
• Limestone Grinding System ($/yr)	200 kW for limestone grinding circuit.	99,338	Design estimate.
Gypsum Credit ($/yr)	Gypsum value as cement additive.	-467,858	= -Gypsum Production Rate (tpy -dry basis) * Gypsum Value ($/ton - dry basis)
DAC Subtotal	Direct Annual Costs (DAC)	1,503,034	= SUM of Direct Annual Cost Items
Indirect Annual Costs (IAC)			
Overhead ($/yr)	60% of total labor and material costs	869,619	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Administrative charges ($/yr)	2% of Total Capital Investment	1,262,720	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Property tax ($/yr)	1% of Total Capital Investment	631,360	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Insurance ($/yr)	1% of Total Capital Investment	631,360	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Capital recovery ($/yr)	10.98% x Total Capital Investment	6,932,333	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
IAC Subtotal	Indirect Annual Costs (IAC)	10,327,392	= SUM of Indirect Annual Cost Items
Annualized Costs			
Total Annual Cost ($/yr)	DAC + IAC	11,830,426	= IAC Subtotal + DAC Subtotal
Control Cost Effectiveness ($/ton)	TAC / Tons SO2 Removed	1,087	= Total Annual Cost ($/yr) / SO2 Removed by Scrubber (tpy)

KG5 Duct Injection Cost Estimate

Item	Basis	Value	Comments
		Capital Cost Estimate	
Purchased equipment Costs			
Duct Injection System Cost (DISC)	Vendor Quote + Plant Estimates	1,455,600	Includes injection system, reagent prep, piping, tanks, silos, and pumps and duct work.
Instrumentation	= 0.10*DISC	145,560	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Sales taxes	= 0.03*DISC	43,668	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Freight	= 0.05*DISC	72,780	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Purchased equipment cost (PEC)	PEC = 1.18*DISC	1,717,608	= Duct Injection System Cost (DISC) + Instrumentation + Sales taxes + Freight
Direct installation costs			
Foundations & supports	Included in PEC	-	Included in DISC
Handling & erection	Included in PEC	-	Included in DISC
Electrical	Included in PEC	-	Included in DISC
Piping	Included in PEC	-	Included in DISC
Insulation	Included in PEC	-	Included in DISC
Painting	Included in PEC	-	Included in DISC
Direct installation costs	Included in PEC	-	Included in DISC
Site preparation & Buildings (SP + BLD.)	As required	500,000	Order of magnitude estimate.
Total Direct Costs (DC)	= PEC + SP +BLD.	2,217,608	= Site preparation & Buildings (SP + BLD.) + Purchased equipment cost (PEC)
Indirect Costs (installation)			
Engineering	= 0.10*PEC	171,761	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Construction and field expenses	= 0.10*PEC	171,761	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Contractor fees	= 0.10*PEC	171,761	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Start-up	= 0.01*PEC	17,176	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Performance test	= 0.01*PEC	17,176	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Contingencies	= 0.25*PEC	343,522	Conservative estimate of contingency based on level of engineering.
Lost Production During Retrofit	10 days of downtime/kiln	1,440,000	Based on lost production of $40/ton and a capacity of 150 tph.
Total Indirect Costs (IC)	= 0.35*PEC	2,333,156	= SUM of Indirect Cost Elements
Total Capital Investment $ (TCI)	= IC+ DC	4,550,764	= Total Direct Costs (DC) + Total Indirect Costs (IC)

Annualized Cost Estimate			
Annual Cost Inputs			
Reagent Ratio (moles limes/mole SO2 removed)	Estimate.	1.0	1.0 reagent ration estiamted to achieve 20% reduction.
Operating Labor Cost ($/hr)	Lafarge Data; unburdened cost.	23.78	Lafarge Data
Supervisory Labor Cost ($/hr)	Lafarge Data; unburdened cost.	31.58	Lafarge Data
Maintenance Labor Cost ($/hr)	Lafarge Data; unburdened cost.	24.78	Lafarge Data
Power Cost ($/kW)	Lafarge Data	0.063	Lafarge Data
Lime Cost ($/ton)	Lafarge Data	80	Estimate
Water Cost ($/1000 gal)	Lafarge Data	4.9	Lafarge Data
CKD disposal cost ($/ton)	Lafarge Data	3.5	Lafarge Data
SO2 to Scrubber (tpy)	Based on 2004/2005 Average Emissions.	2,529	
SO2 Removal Efficiency (%)	Design Estimate.	25%	
FGD On-stream Time (%)	Design Estimate.	80%	
SO2 Removed by System (tpy)	Calculated from above values.	506	= SO2 to Scrubber (tpy) * SO2 Removal Efficiency (%) * FGD On-stream Time (%)
Ca(OH)2 MW (lb/lb-mole)	Constant	74	
SO2 MW (lb/lb-mole)	Constant	64	
Water Evaporation Rate (gpm)	Estimate.	50	
Direct Annual Costs (DAC)			
Operating labor			
• Operator ($/yr)	1.0 operators per shift	208,313	Estimate of staffing based on scrubber complexity.
• Supervisor ($/yr)	15% of operator labor	41,496	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Operating materials			
• Water ($/yr)	Based on evaporation rate.	103,018	Based on evaporation.
• Lime ($/yr)	Based on Reagent Ratio of 1.0.	46,778	Calculated based on Reagent Ratio & SO2 removal rate.
• Wastewater disposal ($/yr)	None (FGD is assumed zero discharge)	0	Zero discharge.
• CKD disposal ($/yr)	Assumes 2 tons CKD/ton SO2 removed.	3,540	Need to purge sulfur from system.
Maintenance			
• Labor ($/yr)	0.5 person per shift	108,536	Estimate of staffing based on scrubber complexity.
• Material ($/yr)	100% of maintenance labor	108,536	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Electricity			
• Fans ($/yr)	50 kW for scrubber fans.	22,075	Design estimate.
• Pumps ($/yr)	20 kW for scrubber pumps.	8,830	Design estimate.
DAC Subtotal	Direct Annual Costs (DAC)	651,123	= SUM of Direct Annual Cost Items
Indirect Annual Costs (IAC)			
Overhead ($/yr)	60% of total labor and material costs	370,006	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Administrative charges ($/yr)	2% of Total Capital Investment	91,015	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Property tax ($/yr)	1% of Total Capital Investment	45,508	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Insurance ($/yr)	1% of Total Capital Investment	45,508	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Capital recovery ($/yr)	10.98% x Total Capital Investment	499,674	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
IAC Subtotal	Indirect Annual Costs (IAC)	1,051,711	= SUM of Indirect Annual Cost Items
Annualized Costs			
Total Annual Cost ($/yr)	DAC + IAC	1,702,833	= IAC Subtotal + DAC Subtotal
Control Cost Effectiveness ($/ton)	TAC / Tons SO2 Removed	3,367	= Total Annual Cost ($/yr) / SO2 Removed by System (tpy)

KG6 Duct Injection Cost Estimate

Item	Basis	Value	Comments
		Capital Cost Estimate	
Purchased equipment Costs			
Duct Injection System Cost (DISC)	Vendor Quote + Plant Estimates	1,344,000	Includes injection system, reagent prep, piping, tanks, silos, and pumps and duct work.
Instrumentation	= 0.10*DISC	134,400	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Sales taxes	= 0.03*DISC	40,320	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Freight	= 0.05*DISC	67,200	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Purchased equipment cost (PEC)	PEC = 1.18*DISC	1,585,920	= Duct Injection System Cost (DISC) + Instrumentation + Sales taxes + Freight
Direct installation costs			
Foundations & supports	Included in PEC	-	Included in DISC
Handling & erection	Included in PEC	-	Included in DISC
Electrical	Included in PEC	-	Included in DISC
Piping	Included in PEC	-	Included in DISC
Insulation	Included in PEC	-	Included in DISC
Painting	Included in PEC	-	Included in DISC
Direct installation costs	Included in PEC	-	Included in DISC
Site preparation & Buildings (SP + BLD.)	As required	500,000	Order of magnitude estimate.
Total Direct Costs (DC)	= PEC + SP +BLD.	2,085,920	= Site preparation & Buildings (SP + BLD.) + Purchased equipment cost (PEC)
Indirect Costs (installation)			
Engineering	= 0.10*PEC	158,592	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Construction and field expenses	= 0.10*PEC	158,592	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Contractor fees	= 0.10*PEC	158,592	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Start-up	= 0.01*PEC	15,859	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Performance test	= 0.01*PEC	15,859	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Contingencies	= 0.25*PEC	317,184	Conservative estimate of contingency based on level of engineering.
Lost Production During Retrofit	10 days of downtime/kiln	1,536,000	Based on lost production of $40/ton and a capacity of 160 tph.
Total Indirect Costs (IC)	= 0.35*PEC	2,360,678	= SUM of Indirect Cost Elements
Total Capital Investment $ (TCI)	= IC+ DC	4,446,598	= Total Direct Costs (DC) + Total Indirect Costs (IC)

Annualized Cost Estimate			
Annual Cost Inputs			
Reagent Ratio (moles lime/mole SO2 removed)	Estimate.	1.0	1.0 reagent ration estiamted to achieve 20% reduction.
Operating Labor Cost ($/hr)	Lafarge Data; unburdened cost.	23.78	Lafarge Data
Supervisory Labor Cost ($/hr)	Lafarge Data; unburdened cost.	31.58	Lafarge Data
Maintenance Labor Cost ($/hr)	Lafarge Data; unburdened cost.	24.78	Lafarge Data
Power Cost ($/kW)	Lafarge Data	0.063	Lafarge Data
Lime Cost ($/ton)	Lafarge Data	80	Estimate
Water Cost ($/1000 gal)	Lafarge Data	4.9	Lafarge Data
CKD disposal cost ($/ton)	Lafarge Data	3.5	Lafarge Data
SO2 to Scrubber (tpy)	Based on 2004/2005 Average Emissions.	13,433	
SO2 Removal Efficiency (%)	Design Estimate.	25%	
FGD On-stream Time (%)	Design Estimate.	80%	
SO2 Removed by System (tpy)	Calculated from above values.	2,687	= SO2 to Scrubber (tpy) * SO2 Removal Efficiency (%) * FGD On-stream Time (%)
Ca(OH)2 MW (lb/lb-mole)	Constant	74	
SO2 MW (lb/lb-mole)	Constant	64	
Water Evaporation Rate (gpm)	Estimate.	50	
Direct Annual Costs (DAC)			
Operating labor			
• Operator ($/yr)	1.0 operators per shift	208,313	Estimate of staffing based on scrubber complexity.
• Supervisor ($/yr)	15% of operator labor	41,496	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Operating materials			
• Water ($/yr)	Based on evaporation rate.	103,018	Based on evaporation.
• Lime ($/yr)	Based on Reagent Ratio of 1.0.	248,504	Calculated based on Reagent Ratio & SO2 removal rate.
• Wastewater disposal ($/yr)	None (FGD is assumed zero discharge)	0	Zero discharge.
• CKD disposal ($/yr)	Assumes 2 tons CKD/ton SO2 removed.	18,806	Need to purge sulfur from system.
Maintenance			
• Labor ($/yr)	0.5 person per shift	108,536	Estimate of staffing based on scrubber complexity.
• Material ($/yr)	100% of maintenance labor	108,536	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Electricity			
• Fans ($/yr)	50 kW for scrubber fans.	22,075	Design estimate.
• Pumps ($/yr)	20 kW for scrubber pumps.	8,830	Design estimate.
DAC Subtotal	Direct Annual Costs (DAC)	868,114	= SUM of Direct Annual Cost Items
Indirect Annual Costs (IAC)			
Overhead ($/yr)	60% of total labor and material costs	491,042	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Administrative charges ($/yr)	2% of Total Capital Investment	88,932	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Property tax ($/yr)	1% of Total Capital Investment	44,466	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Insurance ($/yr)	1% of Total Capital Investment	44,466	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Capital recovery ($/yr)	10.98% x Total Capital Investment	488,237	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
IAC Subtotal	Indirect Annual Costs (IAC)	1,157,142	= SUM of Indirect Annual Cost Items
Annualized Costs			
Total Annual Cost ($/yr)	DAC + IAC	2,025,256	= IAC Subtotal + DAC Subtotal
Control Cost Effectiveness ($/ton)	TAC / Tons SO2 Removed	754	= Total Annual Cost ($/yr) / SO2 Removed by System (tpy)

KG5 SNCR Cost Estimate

Item	Basis	Value	Comments
		Capital Cost Estimate	
Purchased equipment Costs			
SNCR System Cost (SNCRSC)	Vendor Quote + Plant Estimates	975,000	Includes injection system, reagent prep, piping, tanks, silos, and pumps and duct work.
Instrumentation	= 0.10*SNCRSC	97,500	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Sales taxes	= 0.03*SNCRSC	29,250	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Freight	= 0.05*SNCRSC	48,750	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Purchased equipment cost (PEC)	PEC = 1.18*SNCRSC	1,150,500	= SNCR System Cost (SNCRSC) + Instrumentation + Sales taxes + Freight
Direct installation costs			
Foundations & supports	Included in PEC	-	Included in SNCRSC
Handling & erection	Included in PEC	-	Included in SNCRSC
Electrical	Included in PEC	-	Included in SNCRSC
Piping	Included in PEC	-	Included in SNCRSC
Insulation	Included in PEC	-	Included in SNCRSC
Painting	Included in PEC	-	Included in SNCRSC
Direct installation costs	Included in PEC	-	Included in SNCRSC
General Facilities (GF)	= 0.05*PEC	57,525	USEPA Control Cost Manual, Sec. 4.2, C1, Table 1.4 (10/2000).
Total Direct Costs (DC)	= PEC + GF	1,208,025	= General Facilities (GF) + Purchased equipment cost (PEC)
Indirect Costs (installation)			
Engineering	= 0.10*PEC	115,050	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Construction and field expenses	= 0.10*PEC	115,050	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Contractor fees	= 0.10*PEC	115,050	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Start-up	= 0.01*PEC	11,505	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Performance test	= 0.01*PEC	11,505	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Contingencies	= 0.25*PEC	230,100	Conservative estimate of contingency based on level of engineering.
Lost Production During Retrofit	5 days of downtime/kiln	720,000	Based on lost production of $40/ton and a capacity of 150 tph.
Total Indirect Costs (IC)	= 0.35*PEC	1,318,260	= SUM of Indirect Cost Elements
Total Capital Investment $ (TCI)	= IC+ DC	2,526,285	= Total Direct Costs (DC) + Total Indirect Costs (IC)

Annualized Cost Estimate			
Annual Cost Inputs			
Reagent Ratio (moles limestone/mole SO2 removed)	Estimate.	1.0	1.0 reagent ration estiamted to achieve 40% reduction.
Operating Labor Cost ($/hr)	Lafarge Data; unburdened cost.	23.78	Lafarge Data
Supervisory Labor Cost ($/hr)	Lafarge Data; unburdened cost.	31.58	Lafarge Data
Power Cost ($/kW)	Lafarge Data	0.063	Lafarge Data
NH3 Cost ($/ton)	Lafarge Data	650	Estimate.
Water Cost ($/1000 gal)	Lafarge Data	4.9	Lafarge Data
NOx to SNCR (tpy)	Based on 2004/2005 Average Emissions.	3,547	
NOx Removal Efficiency (%)	Design Estimate.	44%	
SNCR On-stream Time (%)	Design Estimate.	80%	
NOx Removed by System (tpy)	Calculated from above values.	1,242	= NOx to SNCR (tpy) * NOx Removal Efficiency (%) * SNCR On-stream Time (%)
NH3 MW (lb/lb-mole)	Constant	17	
NOx MW (lb/lb-mole)	Constant	46	
Water Injection Rate (gpm)	Based on 20% NH3/80% H2O by weight.	1.05	Calculated value.
Direct Annual Costs (DAC)			
Operating labor			
• Operator ($/yr)	0.25 operators per shift	41,663	Estimate of staffing based on scrubber complexity.
• Supervisor ($/yr)	15% of operator labor	8,299	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Operating materials			
• Water ($/yr)	Based on evaporation rate.	2,157	Based on water used in injection system.
• NH3 ($/yr)	Based on Reagent Ratio of 1.0.	214,365	Calculated based on Reagent Ratio & SO2 removal rate.
Maintenance			
• Labor & Materials ($/yr)	1.5% of TCI	37,894	USEPA Control Cost Manual, Sec. 4.2, C1, Eqn. 1.21 (10/2000).
Electricity			
• Vaporization System & Pumps ($/yr)	44 kW	19,426	USEPA Control Cost Manual, Sec. 4.2, C1, Eqn. 1.23 (10/2000).
DAC Subtotal	Direct Annual Costs (DAC)	323,804	= SUM of Direct Annual Cost Items
Indirect Annual Costs (IAC)			
Overhead ($/yr)	60% of total labor and material costs	182,626	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Administrative charges ($/yr)	2% of Total Capital Investment	50,526	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Property tax ($/yr)	1% of Total Capital Investment	25,263	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Insurance ($/yr)	1% of Total Capital Investment	25,263	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Capital recovery ($/yr)	10.98% x Total Capital Investment	277,386	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
IAC Subtotal	Indirect Annual Costs (IAC)	561,064	= SUM of Indirect Annual Cost Items
Annualized Costs			
Total Annual Cost ($/yr)	DAC + IAC	884,867	= IAC Subtotal + DAC Subtotal
Control Cost Effectiveness ($/ton)	TAC / Tons NOx Removed	713	= Total Annual Cost ($/yr) / NOx Removed by System (tpy)

KG6 SNCR Cost Estimate

Item	Basis	Value	Comments
		Capital Cost Estimate	
Purchased equipment Costs			
SNCR System Cost (SNCRSC)	Vendor Quote + Plant Estimates	800,000	Includes injection system, reagent prep, piping, tanks, silos, and pumps and duct work.
Instrumentation	= 0.10*SNCRSC	80,000	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Sales taxes	= 0.03*SNCRSC	24,000	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Freight	= 0.05*SNCRSC	40,000	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Purchased equipment cost (PEC)	PEC = 1.18*SNCRSC	944,000	= SNCR System Cost (SNCRSC) + Instrumentation + Sales taxes + Freight
Direct installation costs			
Foundations & supports	Included in PEC	-	Included in SNCRSC
Handling & erection	Included in PEC	-	Included in SNCRSC
Electrical	Included in PEC	-	Included in SNCRSC
Piping	Included in PEC	-	Included in SNCRSC
Insulation	Included in PEC	-	Included in SNCRSC
Painting	Included in PEC	-	Included in SNCRSC
Direct installation costs	Included in PEC	-	Included in SNCRSC
General Facilities (GF)	= 0.05*PEC	47,200	USEPA Control Cost Manual, Sec. 4.2, C1, Table 1.4 (10/2000).
Total Direct Costs (DC)	= PEC + GF	991,200	= General Facilities (GF) + Purchased equipment cost (PEC)
Indirect Costs (installation)			
Engineering	= 0.10*PEC	94,400	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Construction and field expenses	= 0.10*PEC	94,400	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Contractor fees	= 0.10*PEC	94,400	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Start-up	= 0.01*PEC	9,440	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Performance test	= 0.01*PEC	9,440	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.3 (12/1995).
Contingencies	= 0.25*PEC	188,800	Conservative estimate of contingency based on level of engineering.
Lost Production During Retrofit	5 days of downtime/kiln	768,000	Based on lost production of $40/ton and a capacity of 160 tph.
Total Indirect Costs (IC)	= 0.35*PEC	1,258,880	= SUM of Indirect Cost Elements
Total Capital Investment $ (TCI)	= IC+ DC	2,250,080	= Total Direct Costs (DC) + Total Indirect Costs (IC)

Annualized Cost Estimate			
Annual Cost Inputs			
Reagent Ratio (moles limestone/mole SO2 removed)	Estimate.	1.0	1.0 reagent ration estiamted to achieve 40% reduction.
Operating Labor Cost ($/hr)	Lafarge Data; unburdened cost.	23.78	Lafarge Data
Supervisory Labor Cost ($/hr)	Lafarge Data; unburdened cost.	31.58	Lafarge Data
Power Cost ($/kW)	Lafarge Data	0.063	Lafarge Data
NH3 Cost ($/ton)	Lafarge Data	650	Estimate.
Water Cost ($/1000 gal)	Lafarge Data	4.9	Lafarge Data
NOx to SNCR (tpy)	Based on 2004/2005 Average Emissions.	5,748	
NOx Removal Efficiency (%)	Design Estimate.	50%	
SNCR On-stream Time (%)	Design Estimate.	80%	
NOx Removed by System (tpy)	Calculated from above values.	2,299	= NOx to SNCR (tpy) * NOx Removal Efficiency (%) * SNCR On-stream Time (%)
NH3 MW (lb/lb-mole)	Constant	17	
NOx MW (lb/lb-mole)	Constant	46	
Water Injection Rate (gpm)	Based on 20% NH3/80% H2O by weight.	1.94	Calculated value.
Direct Annual Costs (DAC)			
Operating labor			
• Operator ($/yr)	0.25 operators per shift	41,663	Estimate of staffing based on scrubber complexity.
• Supervisor ($/yr)	15% of operator labor	8,299	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Operating materials			
• Water ($/yr)	Based on evaporation rate.	3,994	Based on water used in injection system.
• NH3 ($/yr)	Based on Reagent Ratio of 1.0.	396,957	Calculated based on Reagent Ratio & SO2 removal rate.
Maintenance			
• Labor & Materials ($/yr)	1.5% of TCI	33,751	USEPA Control Cost Manual, Sec. 4.2, C1, Eqn. 1.21 (10/2000).
Electricity			
• Vaporization System & Pumps ($/yr)	71 kW	31,347	USEPA Control Cost Manual, Sec. 4.2, C1, Eqn. 1.23 (10/2000).
DAC Subtotal	Direct Annual Costs (DAC)	516,011	= SUM of Direct Annual Cost Items
Indirect Annual Costs (IAC)			
Overhead ($/yr)	60% of total labor and material costs	290,798	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Administrative charges ($/yr)	2% of Total Capital Investment	45,002	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Property tax ($/yr)	1% of Total Capital Investment	22,501	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Insurance ($/yr)	1% of Total Capital Investment	22,501	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
Capital recovery ($/yr)	10.98% x Total Capital Investment	247,059	USEPA Control Cost Manual, Sec. 5.2, C1, Table 1.4 (12/1995).
IAC Subtotal	Indirect Annual Costs (IAC)	627,860	= SUM of Indirect Annual Cost Items
Annualized Costs			
Total Annual Cost ($/yr)	DAC + IAC	1,143,871	= IAC Subtotal + DAC Subtotal
Control Cost Effectiveness ($/ton)	TAC / Tons NOx Removed	498	= Total Annual Cost ($/yr) / NOx Removed by System (tpy)

APPENDIX C

CALMET Meteorological Stations

Surface Stations
2002, 2003 and 2004

WBAN Number	WMO Number	Station Name	State	Geographic Location		Lambert CC		UTM			Time Zone
				Longitude	Latitude	Easterly	Northerly	Easterly	Northerly	Zone	
				(deg)	(deg)	(km)	(km)	(km)	(km)		
4874	726394	Charlevoix - Newberry Luce Co	MI	85.47	46.32	885.399	757.221	155.894	5139.320	17	5
14808	726395	Wurtsmith AFB	MI	83.40	44.45	1074.281	573.444	309.041	4924.657	17	5
14841	727347	Pellston Emmet County AP	MI	84.78	45.57	949.275	681.352	205.051	5053.226	17	5
14847	727340	SAULT STE MARIE/NWSO	MI	84.35	46.47	968.599	784.893	242.800	5151.391	17	5
14850	726387	TRAVERSE CITY/FAA AIRPORT	MI	85.58	44.73	898.900	580.888	137.112	4963.516	17	5
14898	726450	GREEN BAY/AUSTIN STRAUBEL FIE	WI	88.13	44.48	701.564	530.828	-67.248	4950.327	17	6
86399*	726399	Seul Choix Pt AMOS - false WBAN	MI	85.92	45.92	856.439	708.678	118.499	5096.940	17	5
94814	726380	Houghton Lake Roscommon	MI	84.68	44.37	975.025	550.216	206.794	4919.558	17	5
94849	726390	ALPENA/PHELPS COLLINS AP	MI	83.57	45.07	1051.088	639.300	297.917	4993.599	17	5
94853	726480	Escanaba AWOS	MI	87.03	45.75	773.078	679.921	31.008	5083.982	17	5
94896	726487	Menominee AWOS	MI	87.63	45.13	733.824	606.346	-21.357	5018.818	17	5

*Pseudo-WBAN number assigned for unknown WBAN number.

Upper Air Stations
2002, 2003 and 2004

Station Number	Station Name	State	Geographic Location		Lambert CC		UTM			Time Zone
			Longitude	Latitude	Easterly	Northerly	Easterly	Northerly	Zone	
			(deg)	(deg)	(km)	(km)	(km)	(km)		
4837	Gaylord	MI	84.43	44.54	992.082	571.628	227.506	4937.577	17	5
14898	GREEN BAY/AUSTIN STRAUBEL FIE	WI	88.13	44.48	701.564	530.828	-67.248	4950.327	17	6

Precipitation Stations
2002, 2003 and 2004

Station Number	Station Name	State	Geographic Location		Lambert CC		UTM			Time Zone
			Longitude	Latitude	Easterly	Northerly	Easterly	Northerly	Zone	
			(deg)	(deg)	(km)	(km)	(km)	(km)		
200164*	ALPENA WB AIRPORT	MI	83.57	45.07	1050.806	639.596	297.692	4993.940	17	5
200662	BELLAIRE	MI	85.20	44.98	925.333	611.962	168.860	4989.315	17	5
200766	BIG BAY 8 NW	MI	87.87	46.88	695.537	798.422	-23.381	5214.786	17	5
201486	CHATHAM EXP FARM 2	MI	86.92	46.33	774.419	745.086	44.371	5147.770	17	5
202094	DETOUR VILLAGE	MI	83.90	46.00	1010.299	738.259	275.450	5098.137	17	5
202626	ESCANABA	MI	87.03	45.75	773.078	679.921	31.008	5083.982	17	5
202788	FIFE LAKE 1 NNW	MI	85.35	44.58	919.318	566.356	154.653	4945.506	17	5
203199	GLENNIE ALCONA DAM	MI	83.80	44.57	1040.981	581.974	277.671	4938.999	17	5
203391	GRAYLING	MI	84.70	44.65	969.256	580.820	206.611	4950.733	17	5
203516	GWINN 1 W	MI	87.45	46.28	734.439	735.145	3.134	5145.413	17	5
203936*	HOUGHTON LAKE WSO AIRPORT	MI	84.68	44.37	975.025	550.216	206.794	4919.558	17	5
204090	IRON MTN-KINGSFORD WWTP	MI	88.08	45.78	691.610	674.781	-50.350	5094.035	17	5
205073	MANISTIQUE	MI	86.25	45.95	830.658	708.932	93.133	5101.908	17	5
205816	NEWBERRY STATE HOSPITL	MI	85.50	46.33	882.967	758.035	153.648	5140.562	17	5
206438	PELLSTON REGIONAL AP	MI	84.79	45.56	948.651	680.145	204.218	5052.152	17	5
207366	SAULT STE MARIE WSO	MI	84.35	46.47	968.552	785.224	242.814	5151.724	17	5
208246	TRAVERSE CITY	MI	85.57	44.77	899.402	585.097	138.373	4967.569	17	5
208293	TROUT LAKE	MI	85.02	46.20	921.517	748.429	189.856	5124.128	17	5
208417	VANDERBILT 11 ENE	MI	84.45	45.17	980.874	640.766	228.893	5007.628	17	5
476510	PESHTIGO	WI	87.73	45.03	727.152	594.481	-30.148	5008.362	17	6
478267	STURGEON BAY EXP FARM	WI	87.33	44.87	760.302	580.063	-0.032	4988.036	17	6

*Not used for 2002 (contained invalid characters)

APPENDIX D

Seney Receptor Locations and Elevations

CALPUFF Receptor Locations (LCC)

LCC Origin: 40.0N, 97.0W, Standard Parallels: 33.0N, 45.0N

Receptor No.	LCC East (km)	LCC West (km)	z (m)	Description	Distance to Lafarge (km)
Source	1066.867	641.697		Lafarge	
1	827.834	740.858	225.000	Seney	258.785
2	828.472	740.934	225.000	Seney	258.225
3	829.110	741.010	225.000	Seney	257.666
4	829.748	741.086	226.000	Seney	257.107
5	830.386	741.163	226.000	Seney	256.548
6	831.024	741.239	226.000	Seney	255.989
7	831.662	741.315	226.000	Seney	255.432
8	832.300	741.391	226.000	Seney	254.874
9	832.938	741.468	226.000	Seney	254.317
10	833.576	741.544	225.000	Seney	253.760
11	834.214	741.621	224.000	Seney	253.204
12	834.852	741.697	223.000	Seney	252.649
13	835.490	741.774	223.000	Seney	252.093
14	836.128	741.850	222.000	Seney	251.538
15	836.765	741.927	221.000	Seney	250.984
16	837.403	742.004	220.000	Seney	250.430
17	838.041	742.081	220.000	Seney	249.877
18	827.725	741.781	227.000	Seney	259.241
19	828.362	741.857	226.000	Seney	258.682
20	829.000	741.933	227.000	Seney	258.124
21	829.638	742.009	227.000	Seney	257.566
22	830.276	742.085	227.000	Seney	257.008
23	830.914	742.161	228.000	Seney	256.451
24	831.552	742.237	228.000	Seney	255.894
25	832.190	742.314	228.000	Seney	255.338
26	832.828	742.390	227.000	Seney	254.782
27	833.465	742.466	226.000	Seney	254.226
28	834.103	742.543	224.000	Seney	253.671
29	834.741	742.619	223.000	Seney	253.117
30	835.379	742.696	223.000	Seney	252.562
31	836.017	742.773	221.000	Seney	252.009
32	836.654	742.849	221.000	Seney	251.455
33	826.977	742.627	227.000	Seney	260.258
34	827.615	742.703	229.000	Seney	259.700
35	828.253	742.779	229.000	Seney	259.142
36	828.890	742.855	228.000	Seney	258.585
37	829.528	742.931	228.000	Seney	258.028
38	830.166	743.007	229.000	Seney	257.471
39	830.804	743.083	229.000	Seney	256.915
40	831.442	743.160	229.000	Seney	256.359
41	832.079	743.236	228.000	Seney	255.804
42	832.717	743.312	229.000	Seney	255.249
43	833.355	743.389	228.000	Seney	254.695

CALPUFF Receptor Locations (LCC)

LCC Origin: 40.0N, 97.0W, Standard Parallels: 33.0N, 45.0N

Receptor No.	LCC East (km)	LCC West (km)	z (m)	Description	Distance to Lafarge (km)
44	833.993	743.465	225.000	Seney	254.141
45	834.630	743.542	226.000	Seney	253.587
46	835.268	743.618	226.000	Seney	253.034
47	835.906	743.695	226.000	Seney	252.481
48	826.867	743.550	229.000	Seney	260.718
49	827.505	743.626	231.000	Seney	260.161
50	828.143	743.702	231.000	Seney	259.604
51	828.780	743.778	231.000	Seney	259.048
52	829.418	743.854	231.000	Seney	258.492
53	830.056	743.930	230.000	Seney	257.936
54	830.694	744.006	230.000	Seney	257.381
55	831.331	744.082	230.000	Seney	256.827
56	831.969	744.158	229.000	Seney	256.273
57	832.607	744.235	229.000	Seney	255.719
58	833.244	744.311	229.000	Seney	255.165
59	833.882	744.387	227.000	Seney	254.613
60	834.520	744.464	229.000	Seney	254.060
61	835.157	744.541	229.000	Seney	253.508
62	835.795	744.617	229.000	Seney	252.957
63	826.120	744.397	229.000	Seney	261.738
64	826.758	744.472	236.000	Seney	261.181
65	827.395	744.548	235.000	Seney	260.625
66	828.033	744.624	234.000	Seney	260.069
67	828.671	744.700	234.000	Seney	259.514
68	829.308	744.776	233.000	Seney	258.959
69	829.946	744.852	232.000	Seney	258.404
70	830.583	744.928	232.000	Seney	257.850
71	831.221	745.004	232.000	Seney	257.297
72	831.859	745.081	231.000	Seney	256.744
73	832.496	745.157	230.000	Seney	256.191
74	833.134	745.233	229.000	Seney	255.639
75	833.771	745.310	229.000	Seney	255.087
76	834.409	745.386	229.000	Seney	254.536
77	835.047	745.463	229.000	Seney	253.985
78	835.684	745.539	229.000	Seney	253.434
79	826.010	745.319	229.000	Seney	262.202
80	826.648	745.395	236.000	Seney	261.646
81	827.286	745.471	237.000	Seney	261.091
82	827.923	745.547	237.000	Seney	260.536
83	828.561	745.622	236.000	Seney	259.982
84	829.198	745.698	236.000	Seney	259.428
85	829.836	745.775	234.000	Seney	258.875
86	830.473	745.851	234.000	Seney	258.322
87	831.111	745.927	235.000	Seney	257.769
88	831.748	746.003	234.000	Seney	257.217

CALPUFF Receptor Locations (LCC)

LCC Origin: 40.0N, 97.0W, Standard Parallels: 33.0N, 45.0N

Receptor No.	LCC East (km)	LCC West (km)	z (m)	Description	Distance to Lafarge (km)
89	832.386	746.079	232.000	Seney	256.666
90	833.023	746.156	231.000	Seney	256.115
91	833.661	746.232	230.000	Seney	255.564
92	834.298	746.309	230.000	Seney	255.014
93	834.936	746.385	229.000	Seney	254.464
94	825.901	746.242	238.000	Seney	262.668
95	826.538	746.317	239.000	Seney	262.114
96	827.176	746.393	239.000	Seney	261.560
97	827.813	746.469	238.000	Seney	261.006
98	828.451	746.545	238.000	Seney	260.453
99	829.088	746.621	237.000	Seney	259.900
100	829.726	746.697	236.000	Seney	259.348
101	830.363	746.773	236.000	Seney	258.796
102	831.000	746.849	236.000	Seney	258.244
103	831.638	746.926	236.000	Seney	257.694
104	832.275	747.002	234.000	Seney	257.143
105	832.913	747.078	233.000	Seney	256.593
106	825.154	747.088	238.000	Seney	263.691
107	825.791	747.164	242.000	Seney	263.137
108	826.429	747.240	242.000	Seney	262.584
109	827.066	747.316	242.000	Seney	262.031
110	827.703	747.391	240.000	Seney	261.478
111	828.341	747.467	240.000	Seney	260.926
112	828.978	747.543	240.000	Seney	260.374
113	829.615	747.619	239.000	Seney	259.823
114	830.253	747.696	238.000	Seney	259.272
115	830.890	747.772	238.000	Seney	258.722
116	831.528	747.848	237.000	Seney	258.172
117	832.165	747.924	236.000	Seney	257.623
118	825.682	748.087	244.000	Seney	263.608
119	826.319	748.162	244.000	Seney	263.056
120	826.956	748.238	244.000	Seney	262.504
121	827.594	748.314	243.000	Seney	261.953
122	828.231	748.390	242.000	Seney	261.402
123	828.868	748.466	242.000	Seney	260.851
124	829.505	748.542	241.000	Seney	260.301
125	830.143	748.618	240.000	Seney	259.751
126	830.780	748.694	240.000	Seney	259.202
127	831.417	748.770	238.000	Seney	258.653
128	832.054	748.847	236.000	Seney	258.105
129	825.572	749.009	244.000	Seney	264.082
130	826.209	749.085	244.000	Seney	263.531
131	826.846	749.161	244.000	Seney	262.980
132	827.484	749.237	244.000	Seney	262.430
133	828.121	749.312	244.000	Seney	261.880

CALPUFF Receptor Locations (LCC)

LCC Origin: 40.0N, 97.0W, Standard Parallels: 33.0N, 45.0N

Receptor No.	LCC East (km)	LCC West (km)	z (m)	Description	Distance to Lafarge (km)
134	828.758	749.388	244.000	Seney	261.330
135	829.395	749.464	243.000	Seney	260.781
136	830.032	749.541	243.000	Seney	260.233
137	830.670	749.617	240.000	Seney	259.684
138	831.307	749.693	239.000	Seney	259.137
139	831.944	749.769	238.000	Seney	258.590
140	825.462	749.932	245.000	Seney	264.558
141	826.100	750.007	245.000	Seney	264.008
142	826.737	750.083	245.000	Seney	263.458
143	827.374	750.159	244.000	Seney	262.909
144	828.011	750.235	244.000	Seney	262.360
145	828.648	750.311	244.000	Seney	261.812
146	829.285	750.387	244.000	Seney	261.264
147	829.922	750.463	243.000	Seney	260.716
148	830.559	750.539	241.000	Seney	260.169
149	831.196	750.615	240.000	Seney	259.623
150	831.834	750.692	240.000	Seney	259.077
151	825.353	750.854	247.000	Seney	265.037
152	825.990	750.930	246.000	Seney	264.488
153	826.627	751.006	245.000	Seney	263.939
154	827.264	751.082	245.000	Seney	263.391
155	827.901	751.158	244.000	Seney	262.843
156	828.538	751.233	244.000	Seney	262.296
157	829.175	751.309	244.000	Seney	261.749
158	829.812	751.386	244.000	Seney	261.203
159	830.449	751.462	242.000	Seney	260.657
160	831.086	751.538	241.000	Seney	260.111
161	831.723	751.614	241.000	Seney	259.566
162	825.243	751.777	247.000	Seney	265.518
163	825.880	751.853	246.000	Seney	264.970
164	826.517	751.928	246.000	Seney	264.422
165	827.154	752.004	245.000	Seney	263.875
166	827.791	752.080	245.000	Seney	263.329
167	828.428	752.156	244.000	Seney	262.782
168	829.065	752.232	244.000	Seney	262.237
169	829.702	752.308	244.000	Seney	261.691
170	830.339	752.384	243.000	Seney	261.146
171	830.976	752.460	242.000	Seney	260.602
172	825.134	752.700	247.000	Seney	266.002
173	825.770	752.775	247.000	Seney	265.455

APPENDIX E

Model Summary Results and
Example CALPOST Output for Baseline 2002 Model

All other model output and input files provided on enclosed CD

Delta Deciview Ranking (4km CALMET Runs)

		Year of Meteorology											
		2002				2003				2004			
Class I Area	Delta Deciview Rank	Baseline	Scenario 1: SNCR KG5&6, Wet Scrub KG6	Scenario 2: SNCR KG5&6, Wet Scrub KG6, DAA KG5	Scenario 3: SNCR KG5&6, Wet Scrub KG5&6	Baseline	Scenario 1: SNCR KG5&6, Wet Scrub KG6	Scenario 2: SNCR KG5&6, Wet Scrub KG6, DAA KG5	Scenario 3: SNCR KG5&6, Wet Scrub KG5&6	Baseline	Scenario 1: SNCR KG5&6, Wet Scrub KG6	Scenario 2: SNCR KG5&6, Wet Scrub KG6, DAA KG5	Scenario 3: SNCR KG5&6, Wet Scrub KG5&6
Seney	1	2.949	1.637	1.498	1.058	3.866	2.098	1.883	1.364	2.178	1.228	1.141	0.869
	2	2.324	1.357	1.281	1.039	3.38	1.932	1.795	1.275	1.777	0.956	0.874	0.678
	3	1.735	0.896	0.798	0.494	2.945	1.61	1.488	1.198	1.616	0.912	0.855	0.619
	4	1.277	0.702	0.642	0.452	2.579	1.555	1.462	0.996	1.315	0.765	0.729	0.613
	5	1.104	0.561	0.496	0.399	2.346	1.221	1.081	0.774	1.305	0.746	0.701	0.557
	6	1.029	0.53	0.477	0.313	2.054	1.058	0.981	0.702	1.3	0.719	0.661	0.526
	7	0.807	0.484	0.464	0.294	1.983	1.047	0.947	0.656	1.285	0.699	0.641	0.509
	8	0.711	0.371	0.34	0.242	1.852	1.022	0.908	0.644	1.089	0.641	0.614	0.474
	9	0.609	0.314	0.29	0.216	1.747	0.974	0.903	0.639	0.96	0.591	0.572	0.461
	10	0.589	0.306	0.274	0.215	1.733	0.957	0.884	0.625	0.935	0.534	0.505	0.414
	11	0.478	0.273	0.26	0.197	1.438	0.82	0.773	0.603	0.777	0.417	0.384	0.283
	12	0.432	0.244	0.233	0.177	1.437	0.778	0.746	0.564	0.653	0.358	0.332	0.252
	13	0.42	0.214	0.191	0.153	1.385	0.772	0.722	0.527	0.608	0.332	0.302	0.206
	14	0.352	0.197	0.186	0.124	1.301	0.769	0.697	0.471	0.529	0.274	0.249	0.194
	15	0.346	0.184	0.169	0.12	1.096	0.597	0.555	0.422	0.435	0.236	0.222	0.173
	16	0.281	0.151	0.141	0.118	1.073	0.586	0.533	0.41	0.428	0.233	0.219	0.171
	17	0.269	0.149	0.14	0.104	1.02	0.566	0.528	0.364	0.414	0.233	0.218	0.171
	18	0.212	0.117	0.11	0.085	0.889	0.481	0.443	0.326	0.389	0.231	0.215	0.165
	19	0.182	0.104	0.097	0.076	0.81	0.423	0.383	0.264	0.338	0.197	0.191	0.161
	20	0.162	0.094	0.09	0.075	0.68	0.362	0.334	0.257	0.324	0.169	0.15	0.119
	21	0.157	0.089	0.083	0.067	0.581	0.335	0.318	0.25	0.262	0.15	0.142	0.104
	22	0.15	0.074	0.066	0.046	0.524	0.264	0.237	0.155	0.249	0.138	0.13	0.096
No. Days > 0.5 dv -->		10	6	4	2	22	17	17	13	14	10	10	7
98% value (8th high) -->		0.711	0.371	0.340	0.242	1.852	1.022	0.908	0.644	1.089	0.641	0.614	0.474
No. Days 8th high > 0.5 dv -->		3	0	0	0	15	10	10	6	7	3	3	0
Largest delta dv -->		2.9	1.6	1.5	1.1	3.9	2.1	1.9	1.4	2.2	1.2	1.1	0.9
3-yrs Combined 98% value ->		1.301	0.746	0.697	0.509								
3-yrs Comb. Days 98% > 0.5 dv ->		25	12	10	1								
Annualized Control Costs		$0	$11,470,682	$12,877,600	$21,949,728	$0	$11,470,682	$12,877,600	$21,949,728	$0	$11,470,682	$12,877,600	$21,949,728
Modeled Rates (lb/hr)		**All Kilns**											
NOx -->		3947	2447	2447	2447								
SO_2 -->		9734	4487	3852	1947								
Modeled Rates (ton/day)		**All Kilns**											
NOx -->		47.4	29.4	29.4	29.4								
SO_2 -->		116.8	53.8	46.2	23.4								

0.5 dv is critical value, allowed 7 exceedences per year.

Assumptions:
No ammonia limiting method.
CALMET in OBS mode, 12 surface, 2 upper air stations
Average background concentration (not 20% best days)
% Reductions Due to Control:

	KG5	KG6
DAA	20	20
Wet Scrubbing	80	80
SNCR	35	40