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CARBO Ceramics PSD Permit Application- Millen, GA Facility

Volume II

Proposed BACT Analysis

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1.0 CONTROL TECHNOLOGY REVIEW

1.1 BACT Applicability and Methodology

The PSD regulation requires that the Best Available Control Technology (BACT) be applied to all regulated air pollutants emitted in significant amounts. Section 169 of the Clean Air Act defines BACT as an emission limitation reflecting the maximum degree of reduction that the permitting authority (in this case Georgia EPD), on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such a facility through application of production processes and available methods, systems, and techniques. In all cases, BACT must establish emission limitations or specific design characteristics at least as stringent as applicable New Source Performance Standards (NSPS). In addition, if there are no economically reasonable or technologically feasible ways to measure the emissions, and hence to impose an enforceable emissions standard, the source may use a design, equipment, work practice, operations standard, or combination thereof, to reduce emissions of the pollutant to the maximum extent practicable.

The BACT determination should, at a minimum, meet two core requirements.[1] The first core requirement is that the determination follows a "top-down" approach. The second core requirement is that the selection of a particular control system as BACT must be justified in terms of the statutory criteria, be supported by the record, and explain the basis for the rejection of other more stringent candidate control systems.

The procedures for performing a top down BACT analysis are set forth in EPA's Draft New Source Review Workshop Manual (Manual), dated October 1990. One critical step in the BACT analysis is to determine if a control option is technically feasible.[2] If a control is determined to be infeasible, it is eliminated from further consideration. The Manual applies several criteria for determining technical feasibility. The first is straightforward. If the control has been installed and operated by the type of source under review, it is demonstrated and technically feasible.

For controls not demonstrated using this straightforward approach, the Manual applies a more complex approach that involves two concepts for determining technical feasibility: availability and applicability. A technology is considered available if it can be obtained through commercial channels. An available control is applicable if it can be reasonably installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

The Manual also requires available technologies to be applicable to the source type under consideration before a control is considered technically feasible. For example, deployment of the control technology on the existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility. However, even in this instance, the Manual would allow an applicant to make a demonstration to

[1] The discussion of the core requirements is taken from the Preamble to the Proposed NSR Reform, 61 FR38272.

[2] Discussion on technical feasibility is taken from the PSD Final Determination for AES Londonderry, L.L. C., Rockingham County, New Hampshire. The PSD Final Determination was written by the U.S. EPA Region I, Air Permits Program.

the contrary. For example, the applicant could show that unresolved technical difficulties with applying a control to the source under consideration (e.g., because of the size of the unit, location of the proposed site and operating problems related to the specific circumstances of the source) make a control technically infeasible.

The five steps of a top-down BACT review procedure as identified by USEPA per BACT guidelines are listed below:

<u>Step 1: Identify all control technologies</u>
<u>Step 2: Eliminate technically infeasible options</u>
<u>Step 3: Rank remaining control technologies by control effectiveness</u>
<u>Step 4: Evaluate most effective controls and document results</u>
<u>Step 5: Select BACT</u>

Once a comprehensive list of all control technologies has been developed, a demonstration of technical infeasiblity should be clearly documented and show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically feasible control technologies should then be ranked based on their control effectiveness, expected emission rate and reduction, energy impacts, environmental impacts, and economic impacts. Once a case-by-case evaluation has been done on each control technology, the most effective option should be selected as BACT.

1.2 Summary of Emission Units Subject to BACT

40 CFR Part 52.21(j) requires a major modification to apply best available control technology for each regulated NSR pollutant which would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit. Table 1.2-1 below displays the NSR pollutants for which a BACT analysis is required and the proposed emission units for which a net increase in those pollutants will occur.

For the purpose of this permit application, the facility-wide increases from Processing Lines 1-4 in non-HF fluorides is assumed to be less than 3 tpy. Notwithstanding minimal amounts of other fluoride compounds possibly emitted by the calciners, current codified performance testing methods do not provide an empirical mechanism to quantify non-HF fluoride emissions (in-and-of themselves). Fluorides are defined in New Source Performance Standards in 40 CFR Part 60 (Subpart S – Aluminum and Phosphate Fertilizer Manufacturing) as all fluoride compounds as measured per Method 13A or 13B. However, Method 13 does not exclude HF and measures all fluorides as captured in an impinger train). Additionally, Method 26A can be used to measure HF but in actuality Method 26A measures all gaseous fluorides, as simply captured in an impinger train. It would require the development of an alternative test method to accurately determine the net emissions of all non-HF fluorides. In the event that there are non-HF fluorides in an amount greater than 3 tpy, any particulate fluoride emissions would already be controlled as part of the PM/PM_{10} BACT of 0.01 gr/dscf and $PM_{2.5}$ BACT of 0.01 gr/dscf. If there are any gaseous non-HF fluorides in an amount greater than 3 tpy, these emissions are essentially addressed in the case-by-case MACT determination required per Section 112(g)(2)(B) which assumes all gaseous fluorides are HF. There would be no incremental environmental benefit in quantifying any non-HF fluorides, as the final magnitude of emission reductions would be the same as currently proposed in this permit application.

Table 1.2-1. BACT Applicability Summary and Table of Contents

Regulated NSR Pollutants[1]	Net Emissions Increase (tpy)	PSD Significance Threshold[1] (tpy)	BACT Applicable?	Location of BACT Review
Nitrogen Oxide	2,446	40	**Yes**	Attachment A
Carbon Monoxide	1,046	100	**Yes**	Attachment B
Sulfur Dioxide	618	40	**Yes**	Attachment C
Particulate Matter (PM) / Particulate Matter (PM_{10}) / Particulate Matter ($PM_{2.5}$)	249 / 249 / 129	25 / 15 / 10	**Yes / Yes / Yes**	Attachment D
Ozone (VOCs)	66.9	40	**Yes**	Attachment E
Lead	0	0.6	No	
Fluorides (excluding HF)	<3	3	No	
Sulfuric Acid Mist	6.83	7	No	
Hydrogen sulfide (H_2S)	0	10	No	
Total reduced sulfur (TRS)[2]	0	10	No	
Reduced sulfur compounds[3]	0	10	No	
MWC Organics (total Dioxins and Furans)	0	3.50E-06	No	
MWC Metals (as PM)	0	15	No	
MWC Acid Gases (as SO_2 and HCl)	0	40	No	
MWC Landfill emissions (non-methane organic compounds)	0	50	No	
Greenhouse gases (GHG, as tpy CO_2e)	404,304	75,000	**Yes**	Attachment F

[1] Per 40 CFR 52.21(b)(23)
[2] Per 40 CFR 63.1579; includes carbonyl sulfide and carbon disulfide as measured using Method 15, and expressed as an equivalent sulfur dioxide concentration
[3] Per 40 CFR 63.1579; includes hydrogen sulfide, carbonyl sulfide, and carbon disulfide.

1.3 Summary of Proposed BACT

Table 1.3-1 below summarizes the conclusions of the detailed BACT analysis included as Attachments A through F of this Volume.

Table 1.3-1: Summary of Proposed BACT by NSR Pollutant

NSR Pollu-tant	Process	Emission Unit ID Nos.	Proposed BACT
NO_x	Direct-fired Rotary Calciner Nos. 1 – 4	KLN1 – KLN4	The use of Low NO_x process technology with a NO_x emission limit of 121 lbs/hr, each
	Spray Dryer Nos. 1 – 8	SD01 – SD08	The use of Good Combustion Techniques with a NO_x emission limit of 8.3 lbs/hr, each
	Gas Fired Boiler Nos. 1 – 4	BLR1 – BLR4	The use of Ultra-low NO_x Burners to limit NO_x emissions to 12ppm @ 3% O_2, each
	Emergency Generator Nos. 1 – 4	EDG1 – EDG4	The use of Good Combustion Techniques to control NO_x emissions to 4.77 g/bhp-hr and a limit of 500 operating hours per year, each
CO	Direct-fired Rotary Calciner Nos. 1 – 4	KLN1 – KLN4	The use of Good Combustion Techniques with a CO emission limit of 24.7 lbs/hr, each
	Spray Dryer Nos. 1 – 8	SD01 – SD08	The use of Good Combustion Techniques with a CO emission limit of 16.6 lbs/hr, each
	Gas Fired Boiler Nos. 1 – 4	BLR1 – BLR4	The use of Good Combustion Techniques
	Emergency Generator Nos. 1 – 4	EDG1 – EDG4	The use of Good Combustion Techniques with a CO emission limit of 2.6 g/bhp-hr and a limit of 500 operating hours per year, each
SO_2	Direct-fired Rotary Calciner Nos. 1 – 4	KLN1 – KLN4	Exclusive use of Natural Gas or Propane as fuel and the use of a wet scrubber as an add-on control device to limit emissions to 34.25 lbs/hr, each
	Spray Dryer Nos. 1 – 8	SD01 – SD08	Exclusive use of natural gas or propane as fuel
	Gas Fired Boiler Nos. 1 – 4	BLR1 – BLR4	Exclusive use of natural gas or propane as fuel
	Emergency Generator Nos. 1 – 4	EDG1 – EDG4	Limit sulfur in fuel to 15 ppm and a limit of 500 operating hours per year, each.
PM/ PM_{10}	Direct-fired Rotary Calciner Nos. 1 – 4	KLN1 – KLN4	The use of a high efficiency baghouse with a PM/PM_{10} emissions limit of 0.01 gr/dscf, each
	Spray Dryer Nos. 1 – 8	SD01 – SD08	The use of a high efficiency baghouse with a PM/PM_{10} emissions limit of 0.02 gr/dscf, each
	Material Storage and Handling Systems	See Table 3.3-1	The use of a high efficiency baghouse with a PM/PM_{10} emissions limit of 0.01 gr/dscf, each
	Gas Fired Boiler Nos. 1 – 4	BLR1 – BLR4	Exclusive use of natural gas or propane as fuel
	Emergency Generator Nos. 1 – 4	EDG1 – EDG4	Exclusive use of diesel as fuel with a PM/PM_{10} emission limit of 0.055 g/bhp-hr and a limit of 500 operating hours per year, each.

Table 1.3-1: Summary of Proposed BACT by NSR Pollutant (Continued)

NSR Pollu-tant	Process	Emission Unit ID Nos.	Proposed BACT
$PM_{2.5}$	Direct-fired Rotary Calciner Nos. 1 – 4	KLN1 – KLN4	The use of a high efficiency baghouse with a $PM_{2.5}$ emissions limit of 0.01 gr/dscf, each
	Spray Dryer Nos. 1 – 8	SD01 - SD08	The use of a high efficiency baghouse with a $PM_{2.5}$ emissions limit of 0.0075 gr/dscf, each
	Material Storage and Handling Systems	See Table 3.3-1	The use of a high efficiency baghouse with a $PM_{2.5}$ emissions limit of 0.005 gr/dscf, each
	Gas Fired Boiler Nos. 1 – 4	BLR1 – BLR4	Exclusive use of natural gas or propane as fuel
	Emergency Generator Nos. 1 – 4	EDG1 – EDG4	Exclusive use of diesel as fuel with a $PM_{2.5}$ emission limit of 0.055 g/bhp-hr and a limit of 500 operating hours per year each.
VOC	Direct-fired Rotary Calciner Nos. 1 – 4	KLN1 – KLN4	The use of good combustion techniques and dedicated use of natural gas and propane as fuels
	Spray Dryer Nos. 1 – 8	SD01 – SD08	Pollution Prevention with a VOC emission limit of 13.64 tons per twelve-month rolling total period per line (spray dryer pair)
	Gas Fired Boiler Nos. 1 – 4	BLR1 – BLR4	The use of Good Combustion Techniques and dedicated use of natural gas and propane as fuels
	Emergency Generator Nos. 1 – 4	EDG1 – EDG4	The use of Good Combustion Techniques with a maximum 500 hours of operation per year each.
GHG	Direct-fired Rotary Calciner Nos. 1 – 4	KLN1 – KLN4	Limiting GHG emissions to 36,715 tpy CO_2e through the use of the following technologies and practices: • Reject Heat Recovery • Good Combustion Practices • Efficient Process (Calciner) Design and Optimization
	Spray Dryer Nos. 1 – 8	SD01 – SD08	Limiting GHG emissions to 28,760 tpy CO_2e through the use of the following technologies and practices: • Good Combustion Practices • Efficient Process (Dryer) Design and Optimization
	Gas Fired Boiler Nos. 1 – 4	BLR1 – BLR4	Limiting GHG emissions to 5,997 tpy CO_2e through the use of the following technologies and practices: • Exclusive use of natural gas and LPG as fuels • Efficient boiler design, operation, and maintenance practices • Insulation of boiler heated surfaces
	Emergency Generator Nos. 1 – 4	EDG1 –EDG4	Limiting GHG emissions to 844 tpy CO_2e through the use of the following technologies and practices: • Efficient Design and Operational Practices • Good Maintenance Practices • Operation limit of 500 hours per year each

ATTACHMENT A

Detailed NO_x BACT Analysis

VOLUME II, ATTACHMENT A
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NO_x BACT- Direct-Fired Rotary Calciner Nos. 1 – 4 (each)

NO_x BACT- Spray Dryer Nos. 1 – 8 (each)

NO_x BACT- Gas-Fired Boiler Nos. 1 – 4 (each)

NO_x BACT- Diesel Fired Emergency Generator Nos. 1 – 4 (each)

A. Top-Down BACT Analysis: Nitrogen Oxide (NO_x)

A.1 NO_x Review: Direct Fired Rotary Calciner Nos. 1 – 4

NO_x is emitted from the direct-fired rotary calciners due to the combustion of natural gas. Because of the temperature of inlet feed air to the calciner burner, which is preheated using a heat recovery mechanism as an energy efficiency measure, the contribution of the thermal NO_x formation process is enhanced. Combustion control technology, such as low-NO_x process technology, as well as post-combustion technologies including Selective Catalytic Reduction (SCR), Catalytic Baghouse, Selective Non-Catalytic Reduction (SNCR), Regenerative Selective Catalytic Reduction (RSCR), and NO_x Wet Scrubbing, were evaluated as possible BACT measures for control of NO_x emissions from the four direct-fired rotary calciners.

This analysis is based on baseline NO_x emissions per calciner of 121 lb/hr or 530 tpy. This emission rate has been selected based on engineering testing and dispersion modeling impact analyses.

<u>Step 1: Identify all control technologies</u>

In reviewing the BACT alternatives to control emissions of NO_x from the direct-fired rotary calciners, applicable BACT determinations and permits for kilns and calciners at non-metallic mineral processing plants have been reviewed as summarized in Table A.1-1 below:

Table A.1-1: Summary of NO_x Control Technology Determinations for Kilns and Calciners

Facility Name	Location	Agency	Database	Process Type[1]	Permit Date	Process Description	Controls / Type	Emission Limits/description	Comments
Holcim	Mobile, AL	ADEM	RBLC	90.028	Feb-03	Coal fired Kiln/Calciner/Preheater	No controls / case-by-case	2998 tpy and CEMS	This is a Coal-Fired Kiln as opposed to a Gas-Fired Calciner at the Millen facility.
Eagle-Picher Filtration & Minerals, Inc.	Florence, OR	OR DEQ	RBLC	90.024	May-03	Diatomaceous Earth Calciner 1/Dryer 1, Calciner 2/Dryer 2	Good Combustion Control	Calciner/Dryer 1: 6.6 lb/hr 3 hour average Calciner/Dryer 2: 7.1 lb/hr 3 hour average	This calciner is fired using fuel gas as opposed to only natural gas at the Millen facility. Considered in BACT analysis, however, since the product being fired in the calciner is different, there is substantial difference in the resulting NO_x emissions.
Roanoke Cement	Botetourt, VA	VA DEQ	RBLC	90.028	Oct-03	Coal fired lime kiln	Good Combustion Practices and CEMS / PSD BACT	982 lb/hr	This is a Coal -Fired Kiln as opposed to a Gas-Fired Calciner at CARBO Ceramics.
Lehigh Cement Company	Gordo, IA	IA DNR	RBLC	90.028	Dec-03	Coal fired Kiln/Preheater	SNCR, low NO_x, Combustion controls, proper kiln design / PSD BACT	2.85 lb/ton and 1,496 tpy	This is a Coal-Fired Kiln as opposed to a Gas-Fired Calciner at CARBO Ceramics. Additionally, SNCR is technically infeasible for a direct-fired rotary calciner with temperatures below 1100°F near the outlet.
Holcim, Inc.	Artesia, MS	MDEQ	RBLC	90.028	Aug-04	HWDF, Coal, and petroleum coke fired rotary kiln	Good Combustion Practice	2625 LB/T Clinker 30 day rolling period 10 lb/hr NO_x	This is a Coal-Fired Kiln as opposed to a Gas-Fired Calciner at the Millen facility.
Thompson Baker Cement Plant	Alacua, FL	FL DEP	RBLC	90.028	Nov-04	Coal Fired Kiln with in line Raw Mill	SNCR with ESP / PSD BACT	1.95 lb/hr 30-day average and 243.75 lb/hr	This is a Coal-Fired Kiln as opposed to a Gas-Fired Calciner at the Millen facility . Additionally, SNCR is technically infeasible for a direct-fired rotary calciner with temperatures below 1100°F near the outlet.
Brookville Cement Plant	Hernando, FL	FL DEP	RBLC	90.028	Dec-04	Coal Fired Clinker Kiln	SNCR / PSD BACT	1.95 lb/hr 30-day average and 243.75 lb/hr	This is a Coal-Fired Kiln as opposed to a Gas-Fired Calciner at the Millen facility. Additionally, SNCR is technically infeasible for a direct-fired rotary calciner with temperatures below 1100°F near the outlet.
Big River Industries, Inc.	Baton Rouge, LA	LA DEQ	RBLC	90.024	June-06	Direct coal-fired rotary kilns, Nos. 1-4	Good Combustion Practices	57.22 lb/hr Input 41 MMBtu/hr	This is a Coal-Fired Kiln as opposed to a Gas-Fired Calciner at the Millen facility.
Branford Cement Plant	Suwanee, FL	FL DEP	RBLC	90.028	Mar-06	Coal Fired Kiln with in-line Raw Mill	SNCR with Baghouse / PSD BACT	1.95 lb/hr 30 day average with CEMS and 247.7 lb/hr	This is a Coal-Fired Kiln as opposed to a Gas-Fired Calciner at CARBO Ceramics. Additionally, SNCR is technically infeasible for a direct-fired rotary calciner with temperatures below 1100°F near the outlet.
Cemex Southeast, LLC	Brooksville, FL	FL DEP	RBLC	90.028	June-07	Kiln with preheater, calciner, inline raw mill, and air heater	SNCR, low NO_x burners	3.0 LB/T Clinker 30 day rolling period 241 lb/hr NO_x	SNCR is technically infeasible for a direct-fired rotary calciner with temperatures below 1100°F near the outlet.
Big River Industries, Inc. - Livite Division	Livingston. AL	ADEM	RBLC	90.024	July-07	Coal fired rotary kiln	Good Combustion Practices	220 lb/hr	This is a Coal-Fired Kiln as opposed to a Gas-Fired Calciner at the Millen facility.
Houston American Cement, LLC	Perry, GA	GA EPD	Title V Permit	90.028	June-08	Kiln with Inline Raw Mill	Selective Non-Catalytic Reduction (SNCR) in combination with staged and controlled combustion (SCC)/multi-staged combustion (MSC), low NO_x burners, and indirect firing	1068 tons NO_x during any period of 12 consecutive months	SNCR is technically infeasible for a direct-fired rotary kiln with temperatures below 1100°F near the outlet.
GCC Dacotah	Rapid City, SD	DENR	RBLC	90.028	Dec-08	Natural Gas or Coal fired Rotary Kiln #6	Pollution Prevention	2267 tpy	This is a Coal-Fired Kiln as opposed to a Gas-Fired Calciner at the Millen facility .
Seadrift Coke	Port Lavaca, TX	TCEQ	RBLC	90.017	Apr-09	Fuel Gas fired Needle Coke Calciner	Pollution Prevention	415 tpy, 95 lb/hr	This is a Fuel Gas-Fired Kiln as opposed to a Gas-Fired Calciner at the Millen facility.
CARBO Ceramics - Toomsboro	Toomsboro, GA	GA EPD	Title V Permit	90.017	Dec-09	Each Calciner	Good combustion techniques, low NO_x burner, use of clean fuels / PSD	121 lb/hr (heat input 60 MMBtu/hr)	Calciner Nos. 3 and 4 are identical in most respects to new Calciner Nos. 1 through 4.
CARBO Ceramics - McIntyre	McIntyre, GA	GA EPD	Title V Permit	90.017	Dec-09	Rotary Calciner Nos. 1 and 2	Good combustion techniques, low NO_x burner, use of clean fuels / PSD	82 lb/hr (heat input 30 MMBtu/hr)	Calciner Nos. 1 and 2 are similar in operation to new Calciner Nos. 1 through 4.
Cemex Southeast, LLC	Clinchfield, GA	GA EPD	Title V Permit	90.028	Jan-10	Dry process Portland cement manufacturing line consisting of a preheater/calciner rotary cement kiln	Selective Non-Catalytic Reduction (SNCR) in combination with staged and controlled combustion (SCC) and low NO_x burners	1,370 tons for 12 month rolling period	SNCR is technically infeasible for a direct-fired rotary kiln with temperatures below 1100°F near the outlet

[1] 90.017 = Calciners & Dryers and Mineral Processing Facilities, 90.024 = Nonmetallic Mineral Processing (excludes 90.017), 90.028 = Portland Cement Manufacturing; All Process types beginning with 90 are Mineral Products

As a consequence of this review and evaluation of other available control technologies, Selective Catalytic Reduction (SCR), use of a Catalytic Baghouse, Selective Non-Catalytic Reduction (SNCR), Wet Scrubbing, Regenerative Selective Catalytic Reduction (RSCR), and Low NO_x Process Technology are being considered as possible control technology options as noted in Table A.1-2 below.

Table A.1-2: **Evaluated Control Options for NO_x Emissions – Direct Gas-fired Rotary Calciner**

Option No.	Control Technology
1	Selective Non-Catalytic Reduction (SNCR)
2	NO_x Wet Scrubbing
3	Selective Catalytic Reduction (SCR)
4	Catalytic Baghouse
5	Regenerative Selective Catalytic Reduction (RSCR)
6	Low NO_x Process Technology

Option 1 - Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion control technology similar to SCR except that no catalyst bed is used. While the process does not require the presence of a catalyst, the temperature requirement for the system is higher than for SCR. Typically, ammonia or urea is injected into the gas stream at a location where the temperature ranges from 1,600 to 2,200°F. The chemical reactions occurring are similar to the reactions shown for the SCR (see discussion under Option 3). In addition to strict control of temperature, this system requires sufficient residence time for the mixture of ammonia and exhaust gas to chemically react, resulting in NO_x reduction. The degree of emission control possible with SNCR varies widely depending on a variety of factors including the degree of mixing of the stack gas with the injected reagent, the residence time allowed for the reactions to take place, the pre-control concentration of NO_x, and the mole ratio of reagent to NO_x in the stack. Increasing the mole ratio increases NO_x control but at the expense of increased ammonia slip (emissions of unreacted ammonia). The latest compilation[1] of operational results for SNCR as applied to cement kilns indicates the varying effect of these factors, listing a range of actual control efficiencies achieved from as low as 10% to as high as 85%. Therefore, an average of 50% is being used for any costing analysis of SNCR.[2]

Option 2 – NO_x Wet Scrubbing

NO_x wet scrubbing involves passing the exhaust gas through direct contact with water, causing the NO_x to absorb in the water, creating insoluble NO, which will slowly reoxidize to NO_2. Different specialty chemicals can be added to the water stream in the scrubber to facilitate the oxidation of NO to NO_2 (which is water-soluble), thus increasing the effective control efficiency. Additionally, the exhaust gas needs to be less

[1] Per EPA Document EPA-453/R-07-006 "Alternative Control Techniques (ACT) Document Update- NO_x Emissions from New Cement Kilns", November 2007, Table 8-8.

[2] Cost analysis for Calciners and Spray Dryers is performed based on guidance from The ACT Document as it is specific to cement kilns.

than 230°F. Typically the exhaust gas from the direct-fired rotary calciner is at temperatures near 1,100°F, and in order to lower the exhaust stream to an appropriate temperature, a gas pre-quencher will need to be installed. With a pre-quencher and appropriate chemicals added to the water stream, residence time of the scrubber should be minimal and a control efficiency of 90%[3] should be achieved.

Option 3– Traditional Selective Catalytic Reduction (SCR)

SCR involves injection of ammonia or urea into exhaust gas upstream of a catalyst bed, which must be maintained at a temperature of 575 to 750°F. The catalyst serves to lower the reaction energy needed to reduce the NO_x. Nitrogen Oxides are typically reduced to nitrogen gas while passing through the catalyst bed, as shown in the following reactions:

$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$
$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O$

SCR has been primarily used in boilers. Based on the review of records in the RBLC database and evaluation of similar sources, SCR has not been applied nor demonstrated in practice to direct-fired rotary calciners processing kaolin. Rotary cement kilns, although not equivalent, have some similar process characteristics to a direct-fired rotary calciner processing kaolin. There are differences between the two in terms of operating temperatures and their respective materials processed. However, both process units are very similar in terms of particulate dust carryover in the exhaust gas stream, which exacerbates the fouling and plugging issues associated with the installation of an SCR. Our review of U.S. Regulatory Agency databases affirms that there are no installations of SCR units at any kilns or calciners in the United States cement industry.[4, 5, 6, 7, 8]

However, on a worldwide basis, three cement kilns have used an SCR to control for NO_x emissions: Solnhofen Cement Works in Solnhofen, Germany (operated 2001-2006 on a pre-heater kiln), Cementaria di Moneselice (began operation in 2006 on a pre-heater kiln), and Italcementi Sarche di Calavino (began operation in 2007 on a semi-dry kiln). The Solnhofer system was installed with a backup SNCR and low NO_x burners because of extensive fouling and reliability issues with the SCR.[9] The unit was constructed to hold up to 6 catalyst layers, and in January 2006, the original catalyst was replaced with an SNCR after 4.5 years in operation. Those with knowledge of this system have indicated that the first SCR system on a cement kiln might be able to achieve emission

[3] Per BE&K Engineering quote for Wet Scrubber Technology for the CARBO Ceramics Toomsboro facility.
[4] Per EPA Document EPA-453/R-94-004 "Alternative Control Techniques Document- NO_x Emissions from Cement Manufacturing". March 1994.
[5] Per EPA Document EPA-453/R-94-004 "Alternative Control Document Update - NO_x Emissions from New Cement Kilns". November 2007. Section 10.
[6] Per EPA Document EPA-457/R-00-002 "NO_x Control Technologies for the Cement Industry; Final Report" September 19, 2000; Page 69.
[7] "Assessment of NO_x Emissions Reduction Strategies for Cement Kilns – Ellis County Final Report". TCEQ Contract No. 582-04-65589. July 14, 2006. Page 4-4.
[8] "Control Technology Analysis". PN 050020.0051. Prepared by Environmental Quality Management, Inc. for Carolinas Cement Company LLC. February 25, 2008. Page 40.
[9] Page 10; "The Experience of SCR at Solnhofen and its Applicability to US Cement Plants"; www.dep.state.pa.us/DEP/DEPUTATE/airwaste/aq/transport/comments/Lehigh_Attachment_Solnhofen.pdf

levels of 200 mg/m^3 or lower, however, sustainable NO_x control utilizing an SCR has yet to be demonstrated.[10]

In a process kiln such as a direct-fired kaolin calciner, particulate matter from the processed material gets carried over into the exhaust gas stream and eventually into the SCR catalyst bed, thus potentially plugging it. Unlike a utility boiler, the concerns that the catalysts may be fouled or deactivated by the high dust loading as well as contamination from the presence of alkalis and sulfur dioxide (e.g. in cement kilns) are well documented.[11] In addition, during kiln upset conditions, periods of unusually high dust loading can occur. These upset conditions may result in dust buildup on the catalyst beds, plugging and blanking off portions of the catalysts which substantially reduce the amount of catalyst available for NO_x reactions, or completely blocks gas flow, negating the operation of the SCR system and/or the calciner.[12] Because of the fouling problems, an SCR system would need to be installed after the particulate control device to prevent imminent fouling. However, the required particulate control devices typically impose temperature limitations that require cooling of the exhaust gas. Therefore, in such a "low-dust" application of an SCR, the air stream would also have to be re-heated for it to be at an optimum temperature for NO_x control using SCR.[13] Since there is no evidence of this technology being applied to a similar process, there is no empirical data regarding its control efficiency. However, if operated correctly, this system should be able to control up to 90%[14] of NO_x emissions as determined from vendor costing data.

In past communications with Fuel Tech Inc., a potential SCR system equipment vendor, CARBO was told that Fuel Tech's catalyst supplier was raising concerns about the expected filter bag failures and the potential blinding and poisoning of the catalyst. CARBO was also told that "If the baghouse fails to keep these particulates out of the flue gas stream entering the SCR, then the catalyst will suffer an irreversible deactivation event which is not covered by warranty." The catalyst supplier expressed concerns that the particulate had a strong tendency to collect on the catalyst surface as well as other downstream equipment due to its charged state. They also noted that the presence of sodium and potassium compounds, which are SCR catalyst poisons, was a cause of concern in terms of catalyst fouling. Additionally, it should be noted that GAEPD has recognized in recent PSD BACT determinations (including CARBO's recent PSD BACT determination for Process Lines 3 and 4 at the Toomsboro, GA facility) that fouling and plugging issues regarding SCR technology applications on rotary kaolin processing calciners are relevant.[15]

[10] Armendariz, Al. "The Costs and Benefits of Selective Catalytic Reduction on Cement Kilns for Multi-Pollutant Control" Febuary 11, 2008. http://www.4cleanair.org/documents/AlsSCR08report.pdf

[11] Per EPA Document EPA-457/R-00-002 "NO_x Control Technologies for the Cement Industry; Final Report"; September 19, 2000; pages 68-70; Also Table 6-3, Annualized Cost Elements and Factors, pages 87-88.

[12] Schreiber, Jr., Robert J. P.E., QEP, Christa O. Russell, Jeff Evers. "Evaluation of Suitability of Selective Catalytic Reduction and Selective Non-Catalytic Reduction for use in Portland Cement Industry"; Page 7-8

[13] EPA Executive Summary, Draft Report on Controls for New Cement Kilns, November 11, 2006; Page 58.

[14] Based on vendor costing received from Fuel Tech, Inc. for an SCR system to control NO_x emissions.

[15] See page 13, C-E Minerals PSD Permit Review, Preliminary Determination, May 2008; See CARBO Ceramics, see PSD Preliminary Review, p. 17 for NO_x BACT determination

Option 4– Catalytic Baghouse

A catalytic baghouse incorporates a baghouse in which the SCR catalyst is integrated into the filter bag media. Tri-Mer Corporation offers UltraCat ceramic filters that incorporate the NO_x SCR catalyst into a 20 mm thick high-temperature ceramic bag material. The catalytic bag operating temperature range is claimed to be 350-700ºF. While the basic SCR technology is not significantly different from traditional SCR applications, it does promise effectiveness at lower catalyst temperatures and near-immunity to plugging from dust. In this regard, particulates are essentially only collected on the outer surface of the ceramic bag media with the catalyst impregnated in deeper layers of the ceramic bag tube. Thus, theoretically, the catalyst is not expected to be subject to the blinding and plugging of traditional SCR applications when exposed to significant dust loadings. Additionally, as there is not a discrete bed of SCR catalyst bed downstream of the filter bags, a bag rupture will not destroy the entire downstream catalyst volume with particulate fouling. Rather, a ruptured bag does not affect the catalyst in the other bags.[16] The bags and catalyst are rated for effective NO_x and PM control at temperatures from 350-700ºF, which eliminates the reheating requirement typically associated with traditional low-dust SCR. This technology can also be combined with upstream sorbent injection to provide SO_2 and acid gas control, and the bags themselves are traditionally a PM control. However, use of sorbent injection in this application would interfere with the material recirculation process critical to proppant sintering implemented at the Millen facility by contaminating the recovered material with spent sorbent. Therefore, this unit would not be used for SO_2 or acid gas control in this application, which presents serious concerns for its practicality. Given the high SO_2 concentrations at the point where ammonia would be injected for the purpose of NO_x control at the catalyst, there is a risk that large amounts of ammonium sulfate would form and condense in the ductwork and catalytic baghouse, potentially interfering with the airflow and operation of the catalytic baghouse. Additionally, sulfur is known to poison SCR catalysts generally, and it is unknown if exposing the UltraCat bags to SO_2 in the calciner exhaust prior to control by the wet scrubber would foul or inactivate the catalyst.

Research and preliminary communications with Tri-Mer indicate that while the bag material itself[17] has a proven track record, there is no evidence that that the catalytic bag has been successfully demonstrated in practice[18] as a long-term, large-scale operational NO_x control. Sales information provided from the vendor indicates "trial results" suggest some promise,[19] but do not confirm industrial-scale feasibility in any application, particularly in the context of a non-metallic mineral calcining application where normal operating conditions would expose the catalyst to high concentrations of SO_2 and heavy dust loading. As such, CARBO considers the catalytic baghouse technically feasible and a promising experimental technology that is not yet sufficiently proven to be established as BACT for NO_x control in this application.

[16] However, it should be noted that a ruptured bag would allow uncontrolled NO_x emissions in addition to the uncontrolled PM emissions normally associated with bag ruptures, as a ruptured bag effectively forms a path for stack gas to bypass the SCR catalyst.
[17] These filter bags are sold as UIltraTemp bags without SCR catalyst.
[18] See definition at 61 FR 38275, col. 2
[19] http://www.tri-mer.com/hot-gas-filtration.html, as viewed August 3, 2011

Option 5 –Regenerative Selective Catalytic Reduction (RSCR)

RSCR, or Regenerative Selective Catalytic Reduction technology, combines Selective Catalytic Reduction with the Regenerative heat-recovery technology sometimes used in thermal oxidizers, thus resulting in a highly thermally efficient process to control NO_x. The reactions are similar to SCR technology and the process involves the injection of ammonia or urea upstream of a catalyst bed. However, the regenerative nature of this system allows it to be installed downstream from a particulate matter (PM) control device such as a baghouse and carry out SCR reactions with significant reductions in exhaust gas re-heating requirements. Babcock Power Environmental Inc. is a provider of this technology and has been a vendor suggested by GAEPD. According to vendor specifications, this system can provide a control efficiency of up to 70%[20] when installed on a direct-fired rotary calciner. Nitrogen oxides are typically reduced to nitrogen gas while passing through the catalyst bed, as shown in the following reactions:

$4NO + 4\ NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$
$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O$

CARBO Ceramics has conducted an in-depth assessment of the viability of the Babcock Power, Inc. (BPI) - Regenerative Selective Catalytic (RSCR) system for the control of NO_x emissions from direct-fired rotary calciner at the Millen facility. CARBO has previously visited BPI - RSCR system installations in Vermont and New Hampshire. Based on these site visits, CARBO believes that the BPI - RSCR system technology is still very preliminary and has not fully demonstrated its ability to operate continuously and reliably 8,760 hours per year. It was CARBO's observation from the sites visited that the objective of the BPI - RSCR systems at each facility was to operate a minimum number of hours in order to qualify under the state programs for Renewable Energy Credits for having produced electricity from biomass fuels without producing NO_x emissions in excess of the level allowed under the state's renewable energy credit guidelines. Conducting such operations for sustained periods of time is not a critical requirement. Moreover, even operating intermittently, the BPI - RSCR systems was having problems with plugging and fouling. RSCR has not been applied nor demonstrated in practice for direct-fired rotary calciners processing kaolin. Based on CARBO's previous in-depth assessment of the BPI-RSCR system, it has been concluded that the BPI-RSCR system is still not well suited for continuous operation on rotary mineral processing kilns with particulate matter carryover.[21] Additionally, to date, no RSCR systems have been successfully implemented on a kiln or calciner.

Option 6 – Low NO_x Process Technology

This is a combustion control technology that involves the reduction of NO_x emissions through the use of good combustion practices (including combustion zone water injection) and burners that can be tuned to reduce the NO_x emitted by the direct-fired rotary calciners. This control is achieved by design features that regulate the aerodynamic distribution and the mixing of the fuel and air, thus minimizing NO_x emissions. Low NO_x process technology will include firing practices that minimize the possibility of formation

[20] Per costing analysis provided by BPE Inc. on 1/13/2009
[21] CARBO letter of February 9, 2009 to GAEPD Re: RSCR update with final assessment.

of NO_x (in particular thermal NO_x) along with appropriate burner and calciner design, operation, maintenance, and combustion zone water injection. There are no adverse energy or environmental impacts with respect to Low-NO_x Process Technology.

Step 2: Eliminate technically Infeasible Options

Option 1 - Selective Non-Catalytic Reduction (SNCR)

Application of SNCR to direct-fired rotary calciners is exceptionally complex, and no evidence of its use in kaolin direct-fired rotary calciner processes has been found. Its application to the direct-fired rotary calciner would be considered developmental. Additionally, there could be negative effects on product quality due to unknown reactions between the reagent and constituents in the kaolin. The temperature of the flue gas leaving the direct-fired rotary calciners is approximately 1,100-1,200°F, which is too low for the SNCR reactions to proceed. Hence, the reagent would need to be injected into the middle of the rotary calciner. Installing such a system to inject reagent continuously in the middle of a rotating calciner requires making major modifications on the calciner, which again would be developmental. In summary, there is no evidence of this being done in the past and its effects on the process and product quality are unknown. Due to difficulties in continuous injection of reagent in a rotating direct-fired calciner, SNCR technology is infeasible to efficiently implement.[22,23] The only cases of SNCR being implemented on kilns are those in which the outlet kiln temperature is typically above 1,600ºF, such as cement kilns. No non-cement kilns have implemented SNCR for NO_x reduction.

Due to lack of evidence of use of such a system with a direct-fired rotary calciner process, technical difficulties with temperatures high enough to sustain SNCR reactions, the possibility of effects on product quality, and possible environmental impact due to ammonia (NH_3) emissions, SNCR is considered technically infeasible and is not considered further as BACT to control NO_x from the calciners.

Step 3: Rank remaining control technologies by control effectiveness

Table A.1-3: Ranking of Control Technology – Direct Gas-fired Rotary Calciners

Control Technology Ranking	Option No.	Control Technology	Control Efficiency	NO_x Reductions (tpy)
1	2	NO_x Wet Scrubbing	90%	477
2	3	Selective Catalytic Reduction[1]	90%	477
3	4	Catalytic Baghouse[1]	90%	477
4	5	Regenerative Selective Catalytic Reduction[1]	70%	371
5	6	Low NO_x Process Technology	N/A	N/A

[1] These technologies are being evaluated for cost-effectiveness despite concerns about their experimental nature in this application.

[22] Per EPA Document EPA-453/R-94-004 "Alternative Control Techniques Document- NO_x Emissions from Cement Manufacturing," March 1994. Updated November 2007.
[23] Per EPA Document EPA-453/R-94-004 "Alternative Control Document Update - NO_x Emissions from New Cement Kilns". November 2007.

Step 4: Evaluate most effective controls and document results

Table A.1-4 and Table A.1-5 below summarize the energy, environmental, and economic impacts of all remaining control technologies.

Table A.1-4: BACT Control Analysis – Direct Gas-fired Rotary Calciners

						Change in Emissions[3]					
Option No.	Control Technology	Annualized Cost	Cost Effectiveness ($/ton NO_x Reduced)	Total Energy Consumed (MMBtu/yr)	Water Usage (Million gallons/day)	**NO_x (tpy)**	VOC (tpy)	CO (tpy)	GHG (tpy CO_2e)	SO_2 (tpy)	Total PM[1] (tpy)
2	NO_x Wet Scrubbing[2]	$6,247,728	$13,098	8,499	0.108	**-477**	0	0	0	0	0
3	Selective Catalytic Reduction	$3,942,076	$8,265	137,649	0	**-477**	+0.365	+5.57	+8,004	+0.040	+0.504
4	Catalytic Baghouse	$4,193,730	$8,792	3,875	0	**-477**	0	0	0	0	0
5	Regenerative Selective Catalytic Reduction	$5,159,838	$13,908	12,784	0	**-371**	+0.014	+0.217	+311	+0.002	+0.020
6	Low NO_x Process Technology	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A	N/A	N/A

[1] Total PM includes filterables and condensables. All PM assumed to be <2.5 microns.
[2] This process creates “blowdown”, used scrubbant containing dissolved salts at the solubility point which must be disposed of.
[3] Duct Burner required to maintain proper temperature in catalyst. Details provided in Table A.5-5 for SCR and RSCR

Table A.1-5: Economic Impacts Analysis – Direct Gas-fired Rotary Calciners

Option No.	Control Technology	NO_x Controlled (tpy)	NO_x Reduced (tpy)	Installed Capital Cost[1] ($)	Total Annualized Cost[1] ($/yr)	Cost Effectiveness ($/ton NO_x Reduced)	Incremental Cost Effectiveness[2] ($/ton)
2	NO_x Wet Scrubbing	530	477	$7,087,707	$6,247,728	$13,098	$0
3	Selective Catalytic Reduction	530	477	$7,606,475	$3,942,076	$8,265	$0
4	Catalytic Baghouse	530	477	$21,103,856	$4,193,730	$8,792	-$9,131
5	Regenerative Selective Catalytic Reduction	530	371	$12,588,917	$5,161,634	$13,913	$13,913
6	Low NO_x Process Technology	N/A	N/A	N/A	N/A	N/A	$0

[1] As specified in the cost spreadsheets (Sections A.5); includes operating cost and capital recovery.
[2] Incremental cost effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emissions resulting from the respective alternatives.

Based upon the significant cost of using NO_x Wet Scrubbing (option 2), SCR (option 3), Catalytic Baghouse (option 4), and RSCR (option 5), these options are not considered BACT due to their being economically burdensome. The SCR and Catalytic Baghouse options are additionally subject to serious concerns about the sustainable operational feasibility of these technologies for this particular application, given the high dust loading and potential inactivation of catalytic materials by alkali and sulfate poisons.

Step 5: Select BACT

The utilization of Low NO_x Process Technology with an emissions limitation of 121 lbs/hr[24] from each direct-fired rotary calciner, in order to effectively control NO_x emissions from the four new process Direct-fired Rotary Calciners (Emission Unit ID Nos. KLN1-KLN4) is proposed as BACT. Table A.1-6 summarizes the proposed BACT requirements for controlling NO_x emissions from the four direct-fired rotary calciners.

Table A.1-6: NO_x BACT Proposed for Direct-fired Rotary Calciner Nos. 1 – 4

Emission Unit ID Nos.	BACT Limit (each emission unit)
KLN1 – KLN4	The use of Low NO_x process technology to control NO_x emissions from each direct-fired rotary calciner to no more than 121 lbs/hr

[24] Based on engineering tests conducted at the Toomsboro facility on Calciners 1, 2, and 3 from 2006-2011 along with extensive review and evaluation by the process engineers at CARBO, external combustion experts, and technical representatives and extensive discussions with burner manufacturers Aecometric, Maxon, FCT, and Northstar. This is the basis for the proposed NO_x limit and what the facility believes constitutes Low NO_x Process Technology.

A.2 NO_x Review: Spray Dryers Nos. 1 – 8

NO_x is emitted from the spray dryers due to the combustion of natural gas. Combustion control technology such as good combustion techniques as well as post-combustion technologies including selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR) and NO_x wet scrubbing were evaluated for control of NO_x emissions from the four spray dryers.

This analysis is based on baseline NO_x emissions of 8.3 lb/hr or 36.4 tpy which has been selected based on engineering testing and dispersion modeling impact analyses.

Step 1: Identify all control technologies

In reviewing the BACT alternatives to control emissions of NO_x from the spray dryers, applicable BACT determinations and permits for non-metallic mineral processing plants have been reviewed, as summarized in Table A.2-1 below:

Table A.2-1: Summary of NO_x Control Technology Determinations for Spray Dryers

Facility Name	Location	Agency	Data-base	Process Type[1]	Permit Date	Process Description	Controls / Type	Emission Limits/ description
CARBO – Toomsboro	Toomsboro, GA	GA EPD	Title V Permit	90.017	Dec-09	Natural gas-fired spray dryers	Good combustion techniques, low NO_x burner, use of clean fuels / PSD	8.3 lb/hr (heat input = 47 MMBtu/hr)
CARBO-Mcintyre	McIntyre, GA	GA EPD	Title V Permit	90.017	Dec-09	Natural gas-fired spray dryers	Good combustion techniques, low NO_x burner, use of clean fuels / PSD	5.32 lb/hr (heat input = 25 MMBtu/hr)

90.017 = Calciners & Dryers and Mineral Processing Facilities.

No additional spray dryers have been found in EPA's RBLC in the last decade with respect to the minerals products category. As a consequence of our review and evaluation of other available control technologies, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), wet scrubbing, and good combustion techniques are being considered as possible control technology options as noted in Table A.2-2. An RSCR is not being evaluated as this technology is considered too experimental for a spray dryer.

Table A.2-2: Evaluated Control Options for NO_x Emissions – Spray Dryers

Option No.	Control Technology
1	Selective Non-Catalytic Reduction (SNCR)
2	NO_x Wet Scrubbing
3	Selective Catalytic Reduction (SCR)
4	Good Combustion Techniques

Option 1 – Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion control technology similar to SCR except that no catalyst bed is used. While the process does not require the presence of a catalyst, the temperature requirement for the system is higher than for SCR. Typically, ammonia or urea is injected into the gas stream at a location where the temperature ranges from 1,600 to 2,200°F. The chemical reactions occurring are similar to the reactions shown for the SCR (see discussion under Option 3). In addition to strict control of temperature, this system requires sufficient residence time for the mixture of ammonia and exhaust gas to chemically react, resulting in NO_x reduction. The degree of emission control possible with SNCR varies widely depending on a variety of factors, including the degree of mixing of the stack gas with the injected reagent, the residence time allowed for the reactions to take place, the pre-control concentration of NO_x, and the mole ratio of reagent to NO_x in the stack. Increasing the mole ratio increases NO_x control but at the expense of increased ammonia slip (emissions of unreacted ammonia). The latest compilation[25] of operational results for SNCR as applied to cement kilns indicates the varying effect of these factors, listing a range of actual control efficiencies achieved from as low as 10% to as high as 85%. Therefore, an average of 50% is being used for any costing analysis of SNCR.

Option 2 – NO_x Wet Scrubbing

NO_x wet scrubbing involves passing the exhaust gas through direct contact with water causing the NO_x to absorb in the water creating insoluble NO, which will slowly reoxidize to NO_2. Different specialty chemicals can be added to the water stream in the scrubber to facilitate the oxidation of NO to NO_2 (which is water soluble). Additionally, the exhaust gas needs to be less than 230°F, whereas typically the exhaust gas from the Spray Dryers is at temperatures near 950°F. In order to lower the exhaust stream to an appropriate temperature a gas pre-quencher would need to be installed. With a pre-quencher and appropriate chemicals added to the water stream, residence time of the scrubber should be minimal and an efficiency of 90%[26] should be achieved.

[25] Per EPA Document EPA-453/R-07-006 "Alternative Control Techniques (ACT) Document Update- NO_x Emissions from New Cement Kilns", November 2007, Table 8-8.
[26] Per Vendor quote for Wet Scrubber Technology for the Toomsboro facility.

Option 3– Selective Catalytic Reduction (SCR)

SCR involves injection of ammonia or urea upstream of a catalyst bed, which must be maintained at a temperature of 575 to 750°F. The catalyst serves to lower the reaction energy needed. Nitrogen oxides are typically reduced to nitrogen gas while passing through the catalyst bed, as shown in the following reactions:

$4NO + 4\ NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$
$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O$

SCR has been primarily used in boilers. Based on the review of records in the RBLC database, SCR has not been applied to spray dryers in this industry. Since there is no evidence of this technology being applied to a similar process, there is no empirical data regarding its control efficiency. However, literature predicts that if operated correctly, this system can control up to 90%[27] of NO_x emissions.

As an SCR system has not been previously applied to a spray dryer, there is no available cost or performance data specific to this potential application. However, the USEPA has published a study of possible NO_x controls on cement manufacturing rotary kilns, "*Alternative Control Techniques Document – NO_x Emissions from Cement Kilns,* EPA-453/R-94-004." Although not completely equivalent to the Spray Dryers, there is cost data for eight model cement kilns published in this study suggesting using OAQPS' 0.6 power rule to estimate SCR Purchased Equipment Costs (PEC) for a different kiln. The model kiln from the USEPA study used to estimate SCR costs for this project is a preheater kiln with 85,000 acfm exhaust gas flow rate.

Option 4 – Good Combustion Techniques

This is a combustion control technology that involves the reduction of NO_x emissions through the use of good combustion practices that minimize the NO_x emitted by the spray dryers.

Good Combustion Practices would include firing practices to minimize the possibility of formation of NO_x along with proper operation and maintenance. *Note:* An incremental cost analysis is not included in this Top-Down BACT Analysis as the cost per ton pollutant reduced is not close to being cost effective.

Step 2: Eliminate technically infeasible options

Option 1 - Selective Non-Catalytic Reduction (SNCR)

Application of SNCR to spray dryers is very complex, and we have found no evidence of its use in spray drying processes. In addition, the maximum temperature in the spray dryers used at this facility is much too low for the SNCR reactions to proceed (well below 1,600ºF).

[27] Per EPA Document EPA-453/R-94-004 "Alternative Control Techniques Document- NO_x Emissions from Cement Manufacturing, March 1994." (Page 6-64).

Due to lack of evidence of use of such a system with a spray dryer and technical difficulties with attaining temperatures high enough for the SNCR reactions to proceed, SNCR is considered technically infeasible, and is not considered any further in this BACT analysis for spray dryers.

Step 3: Rank remaining control technologies by control effectiveness

Table A.2-3: Ranking of Control Technology – Spray Dryers

Control Technology Ranking	Option No.	Control Technology	Control Efficiency	NO_x Reductions (tpy)
1	2	NO_x Wet Scrubbing	90%	32.7
2	3	Selective Catalytic Reduction	90%	32.7
3	4	Good Combustion Techniques	N/A	N/A

Step 4: Evaluate most effective controls and document results

Table A.2-4 below summarize the energy, environmental, and economic impacts of all remaining control technologies.

Table A.2-4: BACT Control Analysis – Spray Dryers

						Change in Emissions[4]					
Option No.	Control Technology	Annualized Cost	Cost Effectiveness ($/ton NO_x Reduced)	Total Energy Consumed (MMBtu/yr)	Water Usage (Million gallons/day)	**NO_x (tpy)**	VOC (tpy)	CO (tpy)	GHG (tpy CO_2e)	SO_2 (tpy)	Total PM[2] (tpy)
2	NO_x Wet Scrubbing[1]	$1,591,705	$48,648 [3]	7,175	0.007	**-32.7**	0	0	0	0	0
3	Selective Catalytic Reduction	$5,285,465	$161,543	224,078	0	**-32.7**	+0.598	+9.13	+13,124	+0.065	+0.826
4	Good Combustion Techniques	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A	N/A	N/A

[1] This process creates “blowdown”, used scrubbant containing dissolved salts at the solubility point which must be disposed of.
[2] Total PM includes filterables and condensables. All PM assumed to be <2.5 microns.
[3] Does not take into account costs involved in cooling the flue gas stream or treatment of the wastewater resulting from scrubber operation
[4] Duct Burner required to maintain proper temperature in catalyst. Details provided in Table A.6-3 for SCR

No incremental cost analysis was performed for any of the aforementioned control technologies as they are cost ineffective. Based upon the significant cost of using NO_x Wet Scrubbing (option 2), and SCR (option 3), these options are not considered BACT due to their being economically burdensome.

Step 5: Select BACT

The utilization of Good Combustion Techniques with an emissions limitation of 8.3 lbs/hr[28] from each spray dryer, in order to effectively control NO_x emissions from the eight spray dryers (Emission Unit ID Nos. SD01-SD08) is proposed as BACT. Table A.2-5 summarizes the proposed BACT requirements for controlling NO_x emissions from Spray Dryers.

Table A.2-5: NO_x BACT Proposed for Spray Dryers Nos. 1 – 8

Emission Unit ID Nos.	BACT Limit (each emission unit)
SD01 – SD08	The use of Good Combustion Techniques to control NO_x emissions from each spray dryer to 8.3 lb/hr.

[28] Based on engineering tests on Spray Dryer Nos. 1 - 4 at the Toomsboro facility from 2006-2010. Measured NO_x emission rate of the emission tests were used to derive the proposed 8.3 lb/hr BACT limit.

A.3 NO_x Review: Gas Fired Boilers Nos. 1 – 4

The Millen facility is proposing to install four gas-fired boilers, each with a maximum heat input of 9.8 MMBtu/hr. NO_x is emitted from the boilers due to the combustion of natural gas. Combustion control technology such as good combustion techniques as well as post-combustion technologies, including selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR) and NO_x wet scrubbing, were evaluated for control of NO_x emissions from the four gas-fired boilers.

This analysis is based on baseline NO_x emissions of 0.140 lb/hr or 0.613 tpy. This emission rate has been selected based on engineering testing and dispersion modeling impact analyses.

<u>Step 1: Identify all control technologies</u>

In reviewing the BACT alternatives to control emissions of NO_x from the boilers, applicable BACT determinations and permits for commercial and institutional size boilers and furnaces have been reviewed, as summarized in Table A.3-1 below:

Table A.3-1: Summary of NO_x Control Technology Determinations for Gas Fired Boilers

Facility Name	Location	Agency	Data-base	Permit Date	Process Description[1]	Controls / Type	Emission Limits/Description
Kern River Gas Transmission Company – Goodsprings Transmission Station	Clark, NV	Clark Co. DAQ	RBLC	May-06	Commercial/ Institutional-Size Boilers – 3.85 MMBtu/hr	Good Combustion Practices	0.101 lb/MMBtu / 1.6 tpy
Northwest Pipeline Corp.-Mt Vernon Compressor	Skagit, WA	WA-State Dep. Of Ecology	RBLC	June-06	Boiler, Natural Gas – 4.19 MMBtu/hr	Good Combustion Practices	34.0 ppmdv @ 3% O_2. 4 lbs/day
Harrah's Operating Company, Inc.	Clark, NV	Clark Co. DAQ	RBLC	Jan-07	Commercial/ Institutional-Size Boilers – 35.4 MMBtu/hr	Low NO_x burner with FGR	0.035 lb/MMBtu / 29 ppmdv @ 3% O_2
Daimler-Chrysler Corp. – Toledo Supplier Park Paint Shop	Lucas, OH	OH-EPA	RBLC	May-07	Boiler (2), Natural Gas – 20.4 MMBtu/hr	Low NO_x burner with FGR	0.72 lb/hr, 3.5 tpy
Kia Motors	West Point, GA	GA EPD	PSD Permit	July-07	Boiler, Natural Gas – <10 MMBtu/hr	Low NO_x Burners	0.09 lb/MMBtu 30 ppmv @ 3% O_2
Medimmune, Inc.	Frederick, MD	MDE	RBLC	Jan-08	Boiler (4), Natural Gas and Diesel – 29.4 MMBtu/hr	Low NO_x Burners	0.011 lb/MMBtu 9 ppmv @ 3% O_2
Associative Electric Cooperative, Inc. – Chouteau Power Plant	Chouteau, OK	OK DEQ	RBLC	Jan-09	Boiler, Natural Gas – 33.5 MMBtu/hr	Low NO_x Burners	0.07 lb/MMBtu 2.36 lb/hr
CARBO – Toomsboro	Tooms-boro, GA	GA EPD	Title V Permit	Dec-09	Boiler (2), Natural Gas –9.8 MMBtu/hr	Good combustion techniques, low NO_x burner, use of clean fuels / PSD	12 ppmv @ 3% O_2 at dry standard conditions
Flopam, Inc.	Iberville Parish, LA	LA DEQ	PSD Permit	Feb-10	Boiler (10), Natural Gas <10 MMBtu/hr	Low NO_x Burners	0.015 lb/MMBtu 9 ppmv @ 3% O_2
Sabina Petrochemicals, LLC	Port Arthur, TX	TCEQ	RBLC	Aug-10	Boiler, Natural Gas – 228 scf/hr	Low NO_x burners and SCR	0.02 lb/MMBtu monthly 0.007 lb/MMBtu annually

[1] All Processes are type 13.310, external combustion of natural gas <100 MMBtu/hr

As a consequence of our review and evaluation of other available control technologies, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), Wet Scrubbing, and ultra-low NO_x burners are being considered as possible control technology options as noted in Table A.3-2:

Table A.3-2: Evaluated Control Options for NO_x Emissions – Gas Fired Boilers

Option No.	Control Technology
1	NO_x Wet Scrubbing
2	Selective Catalytic Reduction (SCR)
3	Selective Non-Catalytic Reduction (SNCR)
4	Ultra-low NO_x Burners

Option 1 – NO_x Wet Scrubbing

NO_x wet scrubbing involves passing the exhaust gas through direct contact with water causing the NO_x to absorb in the water creating insoluble NO, which will slowly reoxidize to NO_2. Different specialty chemicals can be added to the water stream in the scrubber to facilitate the oxidation of NO to NO_2 (which is water soluble). Additionally, the exhaust gas needs to be less than 230°F, whereas, typically, boiler exhaust gas temperatures are around 380°F. In order to cool the exhaust stream to an appropriate temperature, a gas pre-quencher would need to be installed. With a pre-quencher and appropriate chemicals added to the water stream, residence time of the scrubber should be minimal and an efficiency of 90%[29] should be achieved.

Option 2– Selective Catalytic Reduction (SCR)

SCR involves injection of ammonia or urea upstream of a catalyst bed, which must be maintained at a temperature of 575 to 750°F. The catalyst serves to lower the reaction energy needed for the reduction reaction to take place. Nitrogen Oxides are typically reduced to nitrogen gas while passing through the catalyst bed, as shown in the following reactions:

$4NO + 4\ NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$
$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O$

Option 3 - Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion control technology similar to SCR except that no catalyst bed is used. Without the reaction energy lowering effect of the catalyst, the temperature requirement for the system is higher than for SCR. Typically, ammonia or urea is injected into the gas stream at a location where the temperature ranges from 1,600 to 2,200°F. The chemical reactions occurring are similar to the reactions shown for the SCR. In addition to strict control of temperature, this system requires sufficient residence time for the mixture of ammonia and exhaust gas to chemically react, resulting in NO_x reduction.

[29] Per Vendor quote for Wet Scrubber Technology for the Toomsboro facility.

When operated and maintained correctly, an SNCR system can achieve 30%-50% control of NO_x emissions.[30, 31]

Option 4 –Ultra-low NO_x Burners

This control technology involves the reduction of NO_x emissions through the use of specialized burners that can be tuned to reduce the NO_x emitted by the gas-fired boilers. Ultra-low NO_x Burners (ULNB) limit NO_x formation by controlling both the stoichiometric and temperature profiles of the combustion process. This control is achieved by design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding one or more of the following conditions:

- Reduced oxygen in the primary combustion zone;
- Reduced flame temperature;
- Reduced residence time at peak temperature.

Ultra-low NO_x Burners are a mature technology for the reduction of NO_x formation during combustion in gas fired boilers.

Note: An incremental cost analysis is not included in this Top-Down BACT Analysis as the cost per ton pollutant reduced for all options but the use of Ultra-low NO_x burners is not close to being cost effective.

Step 2: Eliminate technically infeasible options

All the above options are deemed technically feasible for the purposes of this analysis.

Step 3: Rank remaining control technologies by control effectiveness

Table A.3-3: Ranking of Control Technology – Gas Fired Boilers

Control Technology Ranking	Option #	Control Technology	Control Efficiency	NO_x Reductions (tpy)
1	1	NO_x Wet Scrubbing	90%	0.55
2	2	Selective Catalytic Reduction (SCR)	90%	0.55
3	3	Selective Non-Catalytic Reduction (SNCR)	50%	0.31
4	4	Ultra-Low NO_x Burners	N/A	N/A

Step 4: Evaluate most effective controls and document results

Table A.3-4 below summarize the energy, environmental, and economic impacts of all remaining control technologies.

[30] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 4.2, Subsection 1.1 (Document ID EPA-452/B-02-001)
[31] Cost analysis for Boilers and Emergency Generators is performed based on guidance from US EPA Cost Manual (6th edition) as the ACT Document is specific to cement kilns, and the Cost Manual provides a more generic approach.

Table A.3-4: BACT Control Analysis – Gas Fired Boilers

						Change in Emissions[3]					
Option No.	Control Technology	Annualized Cost	Cost Effectiveness ($/ton NO_x Reduced)	Total Energy Consumed (MMBtu/yr)	Water Usage (Million Gallons day)	**NO_x (tpy)**	VOC (tpy)	CO (tpy)	GHG (tpy CO_2e)	SO_2 (tpy)	Total PM[1] (tpy)
1	NO_x Wet Scrubbing[2]	$302,706	$548,499[2]	1,250	0.0001	**-0.55**	0	0	0	0	0
2	Selective Catalytic Reduction	$38,071	$68,985	224	0	**-0.55**	0	0	0	0	0
3	Selective Non-Catalytic Reduction	$132,087	$430,811	224	0	**-0.31**	0	0	0	0	0
4	Ultra-Low NO_x Burners	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A	N/A	N/A

[1] Total PM includes filterables and condensables. All PM assumed to be <2.5 microns.
[2] Does not take into account costs involved in cooling the flue gas stream.
[3] Duct Burner required to maintain proper temperature in catalyst. Details provided in Table A.7-4 for SCR

No incremental cost analysis was performed for any of the aforemention control technologies as cost effectiveness is so high. Based upon the significant cost of using NO_x Wet Scrubbing (option 1), an SCR (option 2), and an SNCR (option 3), these options are not considered BACT due to their being economically burdensome.

Step 5: Select BACT

The utilization of Ultra-low NO_x Burners with an emissions limitation of 12 ppm NO_x @ 3% O_2 from each gas-fired boiler, in order to effectively control NO_x emissions from the gas-fired boilers (Emission Unit ID Nos. BLR1 – BLR4) is proposed as BACT. Table A.3-5 summarizes the proposed BACT requirements for controlling NO_x emissions from the gas-fired boilers.

Table A.3-5: NO_x BACT Proposed for Gas Fired Boilers Nos. 1 – 4

Emission Unit ID Nos.	BACT Limit
BLR1 – BLR4	The use of Ultra-low NO_x Burners to limit NO_x emissions from Boiler Nos. 1 – 4 each to 12ppm @ 3% O_2

A.4 NO_x Review: Emergency Generators Nos. 1 – 4

The facility is proposing to install four (4) diesel fired emergency generators driven by diesel engines rated at 3,058 horsepower each. These generators are necessary support equipment for the new process kilns. NO_x is emitted from the emergency generators due to the internal combustion of diesel fuel. The units will be manufacturer-certified as compliant with the New Source Performance Standard (NSPS) requirements of 40 CFR 60, Subpart IIII emission standards for stationary compression-ignition engines. These standards already require dramatic reductions in NO_x emissions relative to the emissions of pre-2007 engines, and are the basis for the NO_x BACT baseline of 4.77 g/hp-hr.

Combustion control technologies, such as good combustion techniques as well as post-combustion technologies, including selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR) and NO_x wet scrubbing, were evaluated for control of NO_x emissions from four (4) diesel-fired emergency generators.

Step 1: Identify all control technologies

In reviewing the BACT alternatives to control emissions of NO_x from the emergency generators, applicable BACT determinations and permits for Diesel Fired Internal Combustion Engines of comparable ratings have been reviewed, as summarized in Table A.4-1 below:

Table A.4-1: Summary of NO_x Control Technology Determinations for Diesel Fired Internal Combustion Engines

Facility Name	Location	Database	Process Type[1]	Permit Date	Process Description	Controls / Type	Emission Limits/description	Comments
Cinergy – PSI Energy Madison Station	Butler Co., Ohio	RBLC	17.11	Aug-04	Two diesel fired emergency generators each rated at 17.1 MMBtu/hr	None indicated	55.07 lb/hr 13.77 tons per rolling 12 month period	Restricted to operate less than 500 hours per consecutive 12 month period
BP Cherry Point Cogeneration Project	Whatcom County, WA	RBLC	17.11	Jan-05	Emergency generator	The engine must be new and must satisfy the federal engine standards of 40 CFR 89 for year of purchase.	Emission standards from new nonroad compression ignition engines specified in 40 CFR 89.112 and 40 CFR 89.113	Equivalent to Tier I standard per 40 CFR 89.
Marathon Petroleum Company, LLC	Garyville, LA	RBLC	17.11	Dec-06	Two diesel fired emergency generators each rated at 671 hp	Use of diesel with a Sulfur content of 15 ppmv of less	0.031 lb/hp-hr annual average	Permitted for 182 hours of operation per year each
Adm Corn Processing - Cedar Rapids	Linn, IA	RBLC	17.11	June-07	Emergency generator	No specific control technology is specified. Engine is required to meet limits established as BACT (TIER 2 Non-Road). This could require any number of control technologies and operational req. to meet the BACT standard.	4.5 g/bhp-hr, 5.29 tpy	The Tier 2 Nonroad Diesel Standard For NO_x specifies an emission limit of Nitrogen Oxides (NO_x) plus Non-Methane Hydrocarbons (NMHC). Based on background documentation from the Rule's development, the Department separated the limits for NO_x And VOC.
Fairbault Energy Park	Rice, MN	RBLC	17.11	June-07	Emergency generator	None indicated	0.024 lbs/hp-hr, 10.89 g/hp-hr	Higher than Tier I Standard. The engines at the CARBO Ceramics facility will satisfy the federal engine standards of 40 CFR 89 for their respective year of purchase.
ADM Corn Processing	Cedar Rapids, IA	RBLC	17.11	June-07	Emergency Generator rated at 1500 kW	None indicated	4.5 g/bhp-hr, 5.29 tpy	Required to meet the Tier 2 Nonroad Diesel Standard which pecifies an emission limit of Nitrogen Oxides (NO_x) plus Non-Methane Hydrocarbons (NMHC). Based on background documentation in the rule development, the Department separated the limits for NO_x and VOC.
Medimmune Frederick Campus	Frederick, MD	RBLC	17.11	Jan-08	Three (3) diesel (no. 2 fuel oil) fired, emergency generators each rated at 2500 kilowatts (3604 brake horsepower)	None indicated	6.06 g/hp-hr	Higher than Tier II Standard. The engines at the CARBO Ceramics facility will satisfy the federal engine standards of 40 CFR 89 for their respective year of purchase.
Mid American Steel and Wire Company	Madill, OK	PSD Permit	17.11	Sept-08	Emergency Generator rated at 1200 hp	Pollution Prevention	15.6 lb/hr, 3.9 tpy 0.013 lb/hp-hr	Operate less than 500 hours per consecutive 12 month period; Unit predated NSPS Subpart IIII
Associated Electric Cooperative, Inc.	Chouteau, OK	RBLC	17.11	Jan-09	Emergency Generator rated at 2200 hp	None indicated	23.15 lbs/hr 6.4 g/kW-hr	This limit is for NO_x only which is equal to the Tier II standard of 6.4 g/kW-hr for NO_x + Non Methane Hydrocarbons.
Shady Hills Power Company Generating Station	Spring Hill, FL	RBLC	17.11	Jan-09	Emergency Generator rated at 2.5 MW	Pollution prevention	6.9 g/hp-hr of 3 1-hr test runs	Equal to 40 CFR 60 Subpart IIII for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)
Concord Steam Corporation	Concord, NH	RBLC	17.11	Feb-09	Two diesel fired emergency generators rated at 5.6 MMBtu/hr and 11.6 MMBtu/hr	Pollution Prevention	1.98 lb/MMBtu of 3 1-hr test runs	Operate less than 500 hours per consecutive 12 month period
Tate & Lyle Indgredients Americas, Inc.	Webster, IA	RBLC	17.11	Sept-09	Emergency generator	None indicated	6.2 g/kW-hr, 2.39 tpy	This limit is for NO_x only which is believed to equal the Tier II standard of 6.4 g/kW-hr for NO_x + Non Methane Hydrocarbons.
MGM Mirage	Las Vegas, NV	RBLC	17.11	Nov-09	Two diesel fired emergency generators each rated at 2206 hp	Turbocharging, After-cooling, and lean-burn technology	0.0131 lb/hp-hr 28.98 lb/hr	Operating hours restricted to one hour per day and 52 hours per year for each unit
CARBO – Toomsboro	Toomsboro, GA	Title V Permit	17.11	Dec-09	Emergency Generators	None indicated	Emission standards from new nonroad compression ignition engines specified in 40 CFR 89.112 and 40 CFR 89.113	The engines at the CARBO Ceramics facility will satisfy the federal engine standards of 40 CFR 89 for their respective year of purchase.

[1] 17.11 = large internal combustion engines (diesel)

As a consequence of our review and evaluation of other available control technologies, selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), wet scrubbing, and good combustion techniques are being considered as possible control technology options as noted in Table A.4-2:

Table A.4-2: Evaluated Control Options for NO_x Emissions – Diesel Fired Emergency Generators

Option No.	Control Technology
1	Selective Non-Catalytic Reduction (SNCR)
2	NO_x Wet Scrubbing
3	Selective Catalytic Reduction (SCR)
4	Good Combustion Techniques

Option 1 - Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion control technology similar to SCR except that no catalyst bed is used. Without the reaction energy lowering effect of the catalyst, the temperature requirement for the system is higher than for SCR. Typically, ammonia or urea is injected into the gas stream at a location where the temperature ranges from 1,600 to 2,200°F. The chemical reactions occurring are similar to the reactions shown for the SCR. In addition to strict control of temperature, this system requires sufficient residence time for the mixture of ammonia and exhaust gas to chemically react, resulting in NO_x reduction. When operated and maintained correctly, an SNCR system can achieve 30%-50% control of NO_x emissions.[32]

Option 2 – NO_x Wet Scrubbing

NO_x wet scrubbing involves passing the exhaust gas through direct contact with water causing the NO_x to absorb in the water creating insoluble NO, which will slowly reoxidize to NO_2. Different specialty chemicals can be added to the water stream in the scrubber to facilitate the oxidation of NO to NO_2 (which is water soluble). Additionally the exhaust gas temperature needs to be below 230°F whereas per vendor specification, the exhaust gas from the diesel-fired emergency generators is 869°F for EDG1 through 4. In order to cool the exhaust stream to an appropriate temperature a gas pre-quencher would need to be installed. With a pre-quencher and appropriate chemicals added to the water stream, residence time of the scrubber should be minimal and an efficiency of 90%[33] should be achieved.

Option 3– Selective Catalytic Reduction (SCR)

SCR involves injection of ammonia or urea upstream of a catalyst bed, which must be maintained at a temperature of 575 to 750°F. The catalyst serves to lower the reaction energy needed. Nitrogen Oxides are typically reduced to nitrogen gas while passing through the catalyst bed, as shown in the following reactions:

[32] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 4.2, Subsection 1.1 (Document ID EPA-452/B-02-001)
[33] Per Vendor quote for Wet Scrubber Technology for the Toomsboro facility.

$4NO + 4 NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$
$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O$

Option 4 – Good Combustion Techniques

This is a combustion control technology that involves the reduction of NO_x emissions through the use of good combustion practices that minimize the NO_x emitted by the diesel-fired emergency generators.

The diesel-fired emergency generators will be certified to meet the required US EPA Tier II emission standards of 40 CFR Part 89 for Non-road Diesel Engines based on their model year. In order to achieve this certification, the engines are emissions-optimized by their manufacturer. These optimization and design practices vary by manufacturer and model, but certified engines typically include features such as electronically controlled air-fuel ratio and cooled exhaust gas recirculation (EGR). Good Combustion Practices would include firing practices to minimize the possibility of forming NO_x along with operating at optimum conditions and proper maintenance.

Note: An incremental cost analysis is not included in this Top-Down BACT Analysis as the cost per ton pollutant reduced is not close to being cost effective.

<u>Step 2: Eliminate technically infeasible options</u>

Option 1 - Selective Non-Catalytic Reduction (SNCR)

SNCR technology has not been applied to diesel-fired emergency generators. Per vendor specifications, the temperature of the flue gas from the generators will be 869°F for Emergency Generators 1 through 4. This temperature is too low for the SNCR reactions to proceed. The temperature of the flue gas stream would have to be increased significantly to be in the required temperature range to facilitate SNCR reactions to control $NO_{x,}$ requiring additional fuel combustion or similar energy supply to create compatible exhaust temperatures. This process will incur a significant cost. Additionally, considering the large temperature difference, collateral NO_x and CO emissions resulting from the heating process will be significant and further diminish the reduction in NO_x emissions achieved by this option.

Due to lack of evidence of use of such a system on a diesel-fired emergency generator, significant costs and collateral emissions associated with heating the flue gas streams to temperatures high enough to sustain SNCR reactions and possible environmental impact due to ammonia (NH_3) emissions, SNCR is considered technically infeasible and is not considered any further as BACT to control NO_x.

Step 3: Rank remaining control technologies by control effectiveness

Table A.4-3: Ranking of Control Technology – Diesel Fired Emergency Generators

Control Technology Ranking	Option No.	Control Technology	Control Efficiency	NO_x Reduced (tpy)
1	2	NO_x Wet Scrubbing	90%	7.28
2	3	Selective Catalytic Reduction (SCR)	90%	7.28
3	4	Good Combustion Techniques	N/A	N/A

Step 4: Evaluate most effective controls and document results

Table A.4-4 below summarize the energy, environmental, and economic impacts of all remaining control technologies.

Table A.4-4: Summary of BACT Environmental Analysis – Diesel Fired Emergency Generators

						Change in Emissions[3]					
Option No.	Control Technology	Annualized Cost	Cost Effectiveness ($/ton NO_x Reduced)	Total Energy Consumed (MMBtu/yr)	Water Usage (MGD)	**NO_x (tpy)**	VOC (tpy)	CO (tpy)	GHG (tpy CO_2e)	SO_2 (tpy)	Total PM[2] (tpy)
2	NO_x Wet Scrubbing	$768,434	$105,540[2]	218	0.002	**-7.28**	0	0	0	0	0
3	Selective Catalytic Reduction	$78,176	$10,737	2,191	0	**-7.28**	+0.002	+0.040	+179	+0.002	+0.026
4	Good Combustion Techniques	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A	N/A	N/A

[1]Total PM includes filterables and condensables. All PM assumed to be <2.5 microns
[2]Does not take into account costs involved in cooling the flue gas stream.
[3]Duct Burner required to maintain proper temperature in catalyst. Details provided in Table A.8-4 for SCR

No incremental cost analysis was performed for any of the aforementioned control technologies as cost effectiveness is so high. Based upon the significant cost of using NO_x Wet Scrubbing (option 2), and SCR (option 3), these options are not considered BACT due to their being economically burdensome.

Step 5: Select BACT

The utilization of Good Combustion Techniques with an emissions limitation of 4.77 g/bhp-hr[34] for EDG1 through EDG4 each with a federally enforceable limit of 500 hours of operation per year each, in order to effectively control NO_x emissions from the four diesel-fired emergency generators (Emission Unit ID Nos. EDG1-EDG4) is proposed as BACT. Table A.4-5 summarizes the proposed BACT requirements for controlling NO_x emissions from the diesel-fired emergency generators.

Table A.4-5: NO_x BACT Proposed for Diesel Fired Emergency Generator Nos. 1 – 4

Emission Unit ID Nos.	BACT Limit (each emission unit)
EDG1 – EDG4	The use of Good Combustion Techniques to control NO_x emissions from EDG1 through EDG4 to 4.77 g/bhp-hr each and to limit hours of operation to 500 hours per year each.

[34] Based on US EPA Tier II Standards for Non-Road Diesel Equipment per 40 CFR 89, which the generators are designed to meet.

Table A.5-1: NO_x BACT Cost Analysis for Wet NO_x Scrubbers: Direct-fired Calciners Nos. 1 through 4 (each)

Cost Element	Budget Amount	Comments
Capital Costs		
Direct Costs		
Purchased Equipment Cost (PEC)	**$2,147,267**	See Table A.5-1a. Based on vendor quote for a wet scrubber with a design flow rate of 85,000 acfm at another facility. Cost scaled to 63,000 acfm using "6/10th rule": Cost A = Cost B * (Capacity of A / Capacity of B)$^{0.6}$
Direct Installation Costs (DIC)		
Site Preparation	$1,266,384	See Table A.5-1a.
Foundations & Supports	$718,242	
Electrical and instrumentation	$182,768	
Safety systems and equipment	$37,598	
Piping	$74,361	
Ductwork	$53,473	
Total Direct Installation Cost (DIC)	**$2,332,826**	
Freight	$107,363	See Table A.5-1a
Total Direct Cost (TDC)	**$4,587,456**	**TDC=(PEC+DIC+Freight)**
Indirect Costs		
Engineering	$259,844	See Table A.5-1a.
Startup/Performance testing/Training	$149,557	
Contractor Fees	$304,962	
Controls integration	$167,103	
Contingency	$1,093,784	
Cost of Lost Production During Installation	$525,000	
Total Indirect Cost (TIC)	**$2,500,250**	
Total Capital Cost (TCC)	**$7,087,707**	**TCC= (TDC+TIC)**
Annual Costs		
Operating Labor	$16,110	Based on 3 shifts/day, 8,592 operating hours per year at $30/hr, and 1 labor hour/shift per the ACT Document, Ch. 6.1.3.2
Supervisory Labor	$2,710	15% of Operating Labor per the ACT Document, Table 6-3
Maintenance Labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per the ACT Document, Ch. 6.1.3.3
Reagent and Water	$4,164,167	From a vendor estimate for a scrubber system with 1,054.5 tpy of controlled NO_x and Annual Reagent Cost of $9,205,689. Scaled down using ratio of controlled NO_x (i.e. 477 tpy/1054.5 tpy).
Electricity	$138,706	Based on vendor estimate ($154,985) for a scrubber system with design flow rate of 85,000 acfm and incremental motor load of 465 HP. Motor load scaled down using "6/10th rule". Electricity rate is $0.056/kWh.
Maintenance Repair Parts	$501,308	From a vendor estimate ($603,981) for a scrubber system with a design flow rate of 85,000 acfm and annual maintenance and repair costs of $600,000. Scaled down by ratio of flow rates using "6/10th rule"
Administrative and Insurance	$212,631	Assumes 3% of TCC per the ACT Document, Table 6-3
Annual Cost of Lost Production	$525,000	Assumes 1-week/year shutdown for maintenance and repair of control
Capital Recovery Factor	9.44%	Calculated using The ACT Document Chapter 6.1.3.8, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery	$669,029	Capital Recovery = TCC * Capital Recovery Factor
Total Annualized Cost, $	**$6,247,728**	Sum of capital recovery cost and other annual costs above
Total Cost per ton NO_x controlled	**$13,098**	Based on 530 tpy baseline and 90% control; 477 tons removed

Note (1):"The ACT Document" refers to EPA Document *Alternative Control Techniques Document - NO_x Emissions from Cement Manufacturing* (EPA-453/R-94-004)

Table A.5-1a: Detailed Capital Cost Analysis for Wet Scrubbers

Except as noted, per TMTS's preliminary estimate for construction of Tri-Mer wet scrubber using RSMeans Construction Costing data (2007 Edition).
Unless otherwise noted, scaled costs are scaled from 85,000 acfm to 63,000 acfm using "6/10th rule"

Equipment	Cost From Vendor Quote	Notes	Source
Detailed Project Costs			
Direct Costs			
Purchased Equipment Cost (PEC)			
Total from Tri-Mer Lump Sum Price Quote	$2,570,000		Tri-Mer 4/9/07 quote
Total Cost of PEC:	**$2,570,000**		
Scaled Cost of PEC:	**$2,147,267**		
Site Preparation			
Site work, demolition, earth work	$920,200	McIntyre system's design flow rate is 37,000 acfm, so cost scaling will be conducted on that basis	Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility
Total Cost of Site Preparation:	**$920,200**		
Scaled Cost of Site Preparation:	**$1,266,384**		
Foundations & Supports			
Foundations & Supports	$521,900	McIntyre system's design flow rate is 37,000 acfm, so cost scaling will be conducted on that basis	Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility
Total Cost of Foundations & Supports:	**$521,900**		
Scaled Cost of Foundations & Supports:	**$718,242**		
Electrical and Instrumentation			
NO/NO_2 gas analyzer	$119,750	Optional add-on in quote	Tri-Mer 4/9/07 quote
Insulation and Freeze Protection	$26,000	Assumes chemical lines, water line, and recirc lines FG w/ASJ insulation and heat tracing	TMTS/RSMeans
Yard and Local Lighting	$73,000	Includes 18 pole mounted HPS at 40' high and 10 LPS area lights	TMTS/RSMeans
Total Cost of Electrical Equipment:	**$218,750**		
Scaled Cost of Electrical Equipment:	**$182,768**		
Safety Systems and Equipment			
Safety Equipment	$40,000	SCBA, acid suits, etc. and ambient air monitors	MSA Firehawk SCBA or Comparable
Showers/Eyewash Stations	$5,000	Assumes 6 combination ES/EW stations	TMTS/RSMeans
Total Cost of Safety Equipment:	**$45,000**		
Scaled Cost of Safety Equipment:	**$37,598**		
Piping			
Y basket strainers for recirculation systems	$6,000	Used 3" Y basket strainer, CPVC, quantity 10	West Coast Pump, Inc., on-line catalog
Liquid Flowmeters	$83,000	8 to 80 gph , 1/2" NPT flowmeter, quantity 20, CPVC	Omega, on-line brochure, 2x price for PVC model
Total Cost of Piping:	**$89,000**		
Scaled Cost of Piping:	**$74,361**		
Ductwork			
Integral and interconnecting 66" dia UV white PPE ductwork and I/O transitions for between quench and 4-stage Tri-NOx and blower assmbly only	N/A	Incl. In Tri-Mer lump sum	-
Ductwork, hot gas in from plant to stage 1	$49,000	Assumes 200 LF hot gas ductwork, galvanized	TMTS/RSMeans
Non-Tri-Mer Equipment Ductwork	-	Installation cost is included in "Hot Gas Ductwork" line item above.	
Tri-Mer system Installation, Ductwork	N/A	Incl. In Tri-Mer lump sum	-
Stack	$15,000	Assumes 50 LF stack	TMTS/RSMeans
Total Cost of Ductwork:	**$64,000**		
Scaled Cost of Ductwork:	**$53,473**		

Table A.5-1a: Detailed Capital Cost Analysis for Wet Scrubbers

Except as noted, per TMTS's preliminary estimate for construction of Tri-Mer wet scrubber using RSMeans Construction Costing data (2007 Edition).
Unless otherwise noted, scaled costs are scaled from 85,000 acfm to 63,000 acfm using "6/10th rule"

Equipment	Cost From Vendor Quote	Notes	Source
		Freight	
Freight	$128,500	Assumed to be 5% of PEC per table 6-2 of the ACT Document	
Total Cost of Freight:	**$128,500**		
Scaled Cost of Freight:	**$107,363**		
Total Direct Cost:	**$4,587,456**		
		Indirect Costs	
		Engineering	
Detailed Design and Engineering Review of Detailed Design	$300,000		Comparable Experience on other jobs
Air Permit Application, Preparation and Processing	$10,000		Comparable Experience on other jobs
Building Permit	$1,000		Comparable Experience on other jobs
Total Cost of Engineering:	**$311,000**		
Scaled Cost of Engineering:	**$259,844**		
		Start-Up/Performance Testing/Training	
Tri-Mer Assistance, Per Tri-Mer quote, allow 15 days plus travel time and T/L at $950/man day on job and $750/man day travel for 2 personnel	$42,000	Optional add-on in quote	Value of $42K was provided in Tri-Mer Proposal of 4/9/07
Design Firm Assistance during start-up	$45,000		15% of Detailed Design Cost
Wastewater and Air Pollution Control Consultant Assistance during start-up	$75,000		Comparable Experience on other jobs
Stack Testing	$12,000		Comparable Experience on other jobs
Other Testing	$5,000		Comparable Experience on other jobs
Total Cost of Start-Up:	**$179,000**		
Scaled Cost of Start-Up:	**$149,557**		
		Contractor Fees	
Tri-Mer System Installation, Set/Install	N/A	Incl. In Tri-Mer lump sum	-
Non-Tri-Mer Equipment Setting/Installation	$10,000		Comparable Experience on other jobs
Non-Tri-Mer Equipment Piping, incl feed (air, water, and drain piping)	$75,000		Comparable Experience on other jobs
Tri-Mer System Installation, Electrical Feeds, Controls, and Interconnects	$200,000	Note that this is not included in Tri-Mer proposal scope.	Comparable Experience on other jobs
Tri-Mer System Installation, Piping	N/A	Incl. In Tri-Mer lump sum	-
Non-Tri-Mer Electrical, incl panels, mains/feeds, and disconnects	$80,000		Comparable Experience on other jobs
Total Cost of Contractor Fees:	**$365,000**		
Scaled Cost of Contractor Fees:	**$304,962**		
		Controls Integration	
Controls Integration	$200,000	Includes HMI/Graphics development, logic programming, BMS integration	Comparable Experience on other jobs
Total Cost of Controls Integration:	**$200,000**		
Scaled Cost of Controls Integration:	**$167,103**		
Subtotal Indirect Cost:	**$881,466**		
Contingency @ 20%	$1,093,784	20% of sum of Total Direct Cost and Subtotal Indirect Costs due to technology not having been demonstrated in practice for this source category	
Lost Production During Installation	$525,000	Assumes construction takes one week longer with control equipment	
Total Indirect Cost:	**$2,500,250**		

Note (1): 6/10th rule: Cost A = Cost B * (Capacity of A / Capacity of B)$^{0.6}$

Table A.5-2: NO_x Cost Analysis for Selective Catalytic Reduction (SCR) Systems: Direct-fired Rotary Calciners Nos. 1 through 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Cost (PEC)	**$1,525,000**	This cost is based upon Fuel Tech Proposal No. 09-C-020, dated 2/2/09. This is an equipment only proposal.
Direct Installation Costs (DIC)		
Site Preparation	$1,266,384	See Table A.5-2a. Costs scaled using 6/10ths rule from 37,000 acfm quote for construction of a wet scrubber at CARBO McIntyre: Cost A = Cost B * (Capacity of A / Capacity of B)$^{0.6}$
Foundations & Supports	$718,242	
Electrical and Instrumentation	$260,713	See Table A.5-2a
Safety Systems and Equipment	$29,000	
Piping	$75,000	
Ductwork	$227,000	
Duct Burner Package	$48,000	
Initial Spare Parts Inventory	$50,000	
Wastewater Treatment System	$0	Not required
Total Direct Installation Costs (DIC)	**$2,674,338**	
Freight	$27,450	See Table A.5-2a
Total Direct Costs (TDC)	**$4,226,788**	**TDC=(PEC+DIC+Freight)**
Indirect Costs		
Engineering and Project Management	$381,000	See Table A.5-2a
Start-Up, Performance Test, and Training	$82,500	
Contractor Fees	$557,000	
Controls Integration	$200,000	
Contingency @ 30%	$1,634,187	
Cost of Lost Production	$525,000	
Total Indirect Costs (TIC)	**$3,379,687**	
Total Capital Cost (TCC)	**$7,606,475**	**TCC=(TDC+TIC)**
Annual Cost		
Operating Labor	$32,220	Based on 3 shifts/day, 8,592 operating hours per year at $30/hr, and 1 labor hour/shift per the ACT Document, Ch. 6.1.3.2
Supervision Labor	$4,833	15% of Operating Labor Cost per the ACT Document, Table 6-3
Maintenance and Repair Parts	$152,500	10% of Purchased Equipment Cost per the ACT Document, Table 6-3
Cost of Lost Production for Annual Maintenance & Repair	$525,000	Assumes 1-week annual shutdown for maintenance
Electricity	$39,131	As determined in Table A.5-2b
Natural Gas	$1,161,567	As determined in Table A.5-2b
Reagent Chemicals	$798,912	Calculated based on Fuel Tech specification of 22.8 GPH of 40% liquid urea reagent at $4.00/gallon (facility estimate).
Plant air and water	$7,369	Calculated based on Fuel Tech advised usage for water and air and County rates for water
Cost of off-site disposal of purge water	$65,700	Based on comparable experience on other jobs
Administrative and Insurance	$228,194	Assumes 3% of capital cost per the ACT Document, Table 6-3
Overhead	$91,500	60% of Maintenance per the ACT Document, Table 6-3
Capital Recovery Factor	10.98%	Calculated using The ACT Document Chapter 6.1.3.8, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery Cost/Year	$835,150	Total Capital Cost * Total Recovery Factor
Total Annual Cost, $	**$3,942,076**	
Annual Cost $ per Ton NO_x Removed	**$8,265**	Based on 530 tpy baseline and 90% control; 477 tons removed

Note (1):"The ACT Document" refers to EPA Document *Alternative Control Techniques Document - NO_x Emissions from Cement Manufacturing* (EPA-453/R-94-004)

Table A.5-2a: Detailed Budetary Cost Analysis for Selective Catalytic Reduction System: Rotary Calciners 1 through 4 (each)

Estimated for a High Temp. SCR System for a Rotary Calciner by TMTS using "RSMeans" Construction Costing Data , except as noted.

Equipment	Cost From Vendor Quote	Notes	Source
Detailed Capital Costs			
Direct Costs			
Purchased Equipment Cost (PEC)			
Total from Fuel Tech Lump Sum Price in Proposal (Purchase Equipment Cost)	$1,525,000	This is an equipment only proposal.	This cost is based upon Fuel Tech Proposal No. 09-C-020, dated 2/2/09.
Total Cost of PEC:	**$1,525,000**		
Site Preparation			
Site work, demolition, earth work	$920,200	McIntyre system's design flow rate is 37,000 acfm, so cost scaling will be conducted on that basis	Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility
Total Cost of Site Preparation:	**$920,200**		
Scaled Cost of Site Preparation:	**$1,266,384**		
Foundations & Supports			
Foundations & Supports	$521,900	McIntyre system's design flow rate is 37,000 acfm, so cost scaling will be conducted on that basis	Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility
Total Cost of Foundations & Supports:	**$521,900**		
Scaled Cost of Foundations & Supports:	**$718,242**		
Electrical and Instrumentation			
NO/NO_2 gas analyzer	$137,713	One (1) Horiba NO/NO_2 gas analyzer ENDA – 1300 Series, CEMS package, Model #ENOA-1390 with auto calibration, calibration flow path to meet EPA requirements for calibration gas at sample probe, weather resistant enclosure	From File Quotation, Tri-Mer
Triboelectric Dust Detector	$23,000	Auburn Systems Tribo Series or equivalent, 4 sensors with ceramic tips into processor, with 4-20 mA output	File quote, Auburn
Associated Electrical Equipment not provided by Fuel Tech	$100,000	Includes MCC, motor starters, breakers, distribution panels, overload protection, and distribution wiring	Comparable Experience on other jobs
Total Cost of Electrical/Instr.:	**$260,713**		
Safety Systems and Equipment			
Showers/Eyewash Stations	$4,000	Assumes 4 combination ES/EW stations	
Safety Equipment	$25,000	Chemical splash suits, ambient air monitors, etc.	Comparable Experience on other jobs
Total Cost of Safety Equipment:	**$29,000**		
Piping			
SCR and air heater Piping materials and Purge Water Holding Tank	$62,000	Piping for SCR system, schedule 40, and hangers 10' OC, air, water, and drain piping, material portion and 500 gallon holding tank	TMTS/RSMeans and File quote, Tarmac
Insulation and Freeze Protection materials	$13,000	Assumes urea lines, water line, and recirc lines, FG w/ASJ insulation and heat tracing, material portion	TMTS/RSMeans
Total Cost of Piping:	**$75,000**		
Ductwork			
Modifications and additions to existing plant exhaust system.	$29,000	Assumes 150 LF hot gas ductwork, material portion	TMTS/RSMeans
Ductwork for urea decomposition and SCR systems	$135,000	Assumes hot gas ductwork and 10' by 15' by 25' long horizontal flow SCR reactor enclosure and CEMS enclosure, material portion	TMTS/RSMeans
Duct Insulation	$63,000	Insulation, 2' thick, 1# density, FSK facing for ductwork and Cerafelt 8#/ft3 internal fiberboard duct insulation for air heater enclosure, material portion	TMTS/RSMeans and File quote, Thermal Ceramics
Total Cost of Ductwork:	**$227,000**		
Duct Burner Package			
Duct Burner Package	$48,000	Maxon burners, control valves, packaged gas train, flame supervisory system panel, and combustion blower.	File records re Maxon burner quote and based on comparable experience on other jobs
Total Cost of Duct Burner Package:	**$48,000**		

Table A.5-2a: Detailed Budetary Cost Analysis for Selective Catalytic Reduction System: Rotary Calciners 1 through 4 (each)

Estimated for a High Temp. SCR System for a Rotary Calciner by TMTS using "RSMeans" Construction Costing Data , except as noted.

Equipment	Cost From Vendor Quote	Notes	Source
Initial Spare Parts Inventory			
Initial Spare Parts Inventory	$50,000	For SCR system - not included in Fuel Tech proposal	Comparable Experience on other jobs
Total Cost of Spare Parts Inventory:	**$50,000**		
Freight			
Freight	$27,450		Based on 1.5% of Fuel Tech Equipment Cost plus a portion of non Fuel Tech costs
Total Cost of Freight:	**$27,450**		
Total Direct Cost:	**$4,226,788**		
Indirect Costs			
Engineering			
Detailed Design and Engineering Review of Detailed Design	$250,000		Comparable Experience on other jobs
Air Permit Application, Preparation and Processing	$10,000		
Building Permit	$1,000		
Stack Testing	$20,000		
Other Testing	$10,000		
Project Management	$90,000	Oversight of site preparation, equipment construction, and equipment startup	
Total Cost of Engineering:	**$381,000**		
Start-Up, Performance Test, and Training			
Detailed Design Firm Assistance during start-up	$37,500		15% of Detailed Design Cost
Air Pollution Control Consultant Assistance during start-up	$45,000	200 hours at $200/hour for advance prep and on-site assistance plus $5k expenses	
Total Cost of Start-Up, PT, Training.:	**$82,500**		
Contractor Fees			
Labor for Setting/Installation	$120,000	Including rigging and anchor bolts/tie-downs	Comparable Experience on other jobs
Labor for Ductwork	$225,000	Labor portion ductwork and insulation	Means Constr Cost Data
Labor for Piping	$62,000	Labor portion, non-Fuel Tech supplied piping plus assembly of fittings, instrumentation, etc. supplied by Fuel Tech and air heater piping	TMTS/Means and Comparable Experience on other jobs
Labor for Electrical	$150,000		Comparable Experience on other jobs
Total Cost of Contractor Fees:	**$557,000**		
Controls Integration			
Controls Integration	$200,000	Includes HMI/Graphics development, logic programming, BMS integration	Comparable Experience on other jobs
Total Cost of Controls Integration:	**$200,000**		
Subtotal Indirect Costs:	**$1,220,500**		
Contingency @ 30%	$1,634,187	30% of sum of Total Direct Cost and Subtotal Indirect Costs due to control technology not having been demonstrated in practice for this source category	
Lost Production During Installation	$525,000	Assumes construction takes one week longer with control equipment	
Total Indirect Costs:	**$3,379,687**		

Table A.5-2b: NO_x BACT Energy Cost Analysis for Selective Catalytic Reduction: Rotary Calciners 1 through 4 (each)

Gas flowrate:	63,000	[acfm]
Reference temperature:	77	[^oF]
Inlet gas temperature (after baghouse):	405	[^oF]
Gas flowrate:	39,102	[scfm]
Inlet gas density:[1]	0.046	[lb/acf]
Waste gas heat capacity:[2]	0.248	[Btu/lb-^oF]
Output temperature to SCR catalyst:[3]	700	[^oF]
Fuel heat of combustion:[4]	21,502	[Btu/lb]
Fuel density:[4]	0.041	[lb/ft^3]
Duct Heater Fuel Requirement:[5]	9.83	[lb/min]
Duct Heater Fuel Requirement:[6]	241.04	[scfm]
Total Gas Flowrate after Duct Heater:	39,343	[scfm]

	Average Unit Cost[7,8]	Fuel Required	No. Hours per Year[11]		
Duct Burner Natural Gas[9]	8.76 $/Mscf	14.46 Mscf/hr	8,592	$	1,088,514.90
Urea Decomposition Natural Gas[10]	8.76 $/Mscf	0.97 Mscf/hr	8,592	$	73,052.22
Total Annual Natural Gas Usage:	132,599 Mscf/yr			$	1,161,567.12
Incremental Electricity at ID Fan[12,13]	0.056 $/kWh	81 kW	8,592	$	38,551.37
Urea Decomposition Blower[13,14]	0.056 $/kWh	1 kW	8,592	$	579.53
Total Annual Electricity Usage:	702,530 kWh/yr			$	39,130.90

Footnotes

1	Based on ideal gas equation at waste gas exhaust temperature, assuming waste gas is principally air
2	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996
3	Minimum catalyst temperature specified in FuelTech quote
4	Burner fuel is assumed to be natural gas (as methane). Please refer to Table 2.14 of EPA 452/B-02-001 Section 3.2
5	Duct burner fuel needed to sustain the required catalyst temperature of 700 °F Fuel Required (lb/min)= (Inlet Gas Density, lb/acf) * (Gas flow rate, acfm) * [(Waste Gas Heat Capacity, Btu/lb·ºF) * (Output Temperature, ºF) – (Waste Gas Heat Capacity, Btu/lb·ºF) * (Inlet Temperature, ºF)] / (Fuel Heat of Combustion, Btu/lb)
6	Fuel Required (scfm) = Fuel Required (lb/min) / (Fuel Density, lb/ft^3)
7	Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial secto consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
8	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial secto consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 o http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.htm
9	Duct heater is required to re-heat exhaust gas from maximum baghouse temperature (405ºF) to minimum catalyst temperature (700ºF); Fuel Required (Mscf/hr) = (Duct Heater Fuel Requirement/ scfm) * (60 min/hr)
10	Heat required for urea decomposition chamber to allow for decomposition of urea/air mixture to ammonia gas for SCR process: Fuel Required (Mscf/hr) = (0.99 MMBtu/hr) / (1.02 MMBtu/Mscf
11	Assumes 8,760 hour per year potential minus one week (7 days * 24 hours) annual downtime for system maintenance and repair.
12	Incremental electricity required to compensate for additional pressure drop of SCR system is assumed to include duct burner (1"w.c.), additional ductwork (7"w.c.), and SCR catalyst (2.5"w.c.)
13	Power requirement calculated as specified in EPA Air Pollution Control Cost Manual, 6th Edition, Chapter 3.2, Equation 2.42, assuming 60% combined efficiency of the fan and motor.
14	Based on 621 scfm downstream of urea decomposition chamber and 10"w.c. pressure for ammonia injection grid

Table A.5-3: NO_x Cost analysis for a Catalytic Baghouse: Rotary Calciners 1 through 4 (each)

Cost Element	Budget Amount	Basis/Comments
Capital Cost		
Direct Costs		
Capital Cost	$10,395,988	Calculated using "6/10th rule" and escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) PEC_1=[PEC_2 x (Gas $Flowrate_1$/Gas $Flowrate_2$)$^{0.6}$] * (1522.1/943.1) PEC_2 based on the ACT Document Table 6-1, Mode No. 5
Direct Installation Cost (DIC)	$4,678,195	45% Capital Cost per the ACT Document, Chapter 6.1.2
Freight	$519,799	Assumed to be 5% of PEC per the ACT Document, Table 6-2
Total Direct Cost (TDC)	$15,593,982	
Indirect Costs		
Indirect Installation Cost(IIC)	$3,430,676	33% Capital Cost per the ACT Document Chapter 6.1.2
Contingency @ 20%	$2,079,198	20% of PEC (Capital Cost) per the ACT Document, Chapter 6.1.2
Total Indirect Cost (TIC)	$5,509,874	
Total Capital Cost (TCC)	**$21,103,856**	
Annual Cost		
Operating Labor	$32,850	Based on 3 shifts/day, 8,760 operating hours per year at $30/hr, and a labor factor of 1 hour per/shift per the ACT Document, Ch. 6.1.3.2
Supervision Labor	$4,928	15% of Operating Labor per the ACT Document, Table 6-3
Ammonia Reagent	$13,284	AR_1=AR_2 x (Emissions $_1$ / Emissions $_2$) * (1522.1/943.1) (AR_2=$238,000, $Emissions_2$ = 240lbs/hr) Calculated from ammonia reagent cost of model kiln from USEPA study, scaled down according to uncontrolled NO_x emission rates. Costs escalated using Marshal and Swift Annual Average Cost Index for 2nd Qtr. 2010.
Catalyst	$559,992	CT_1=CT_2 x (Gas $Flowrate_1$/Gas $Flowrate_2$) * (1522.1/943.1) (CT_2=$293,000, Gas $Flowrate_2$ = 53,200 dscfm) Estimated from catalyst cost of an SCR installed in a model cement kiln described in the ACT Document, Table 6-15
Energy Costs	$632,471	See Table A.5-3a
Catalyst Maintenance	$0	Multi-compartment baghouse can be maintained online
Administrative and Insurance	$633,116	Assumes 3% of capital cost per the ACT Document, Table 6-3
Capital Recovery Factor	10.98%	Calculated using the ACT Document, Chapter 6.1.3.8, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery	$2,317,090	Total Capital Cost * Total Recovery Factor
Total Annualized Cost, $	**$4,193,730**	
Total Cost per ton NO_x controlled	**$8,792**	Based on 530 tpy baseline and 90% control; 477 tons removed

Note (1):"The ACT Document" refers to EPA Document *Alternative Control Techniques Document - NO_x Emissions from Cement Manufacturing* (EPA-453/R-94-004); *Alternative Control Techniques Document - NO_x Emissions from New Cement Kilns* (EPA-453/R-07-006, November 2007)

Table A.5-3a: NO_x BACT Energy Cost Analysis for a Catalytic Baghouse: Rotary Calciners 1 through 4 (each)

Gas flowrate:	63,000	[acfm]
Reference temperature:	77	[^oF]
Inlet gas temperature (after baghouse):	405	[^oF]
Gas flowrate:	39,102	[scfm]

	Average Unit Cost[1]	Electricity Required	No. Hours per Year[2]		
Incremental Electricity at ID Fan[3,4]	0.56 $/kWh	130 kW	8,760	$	632,470.55
Total Annual Electricity Usage:	1,135,495 kWh/yr			$	632,470.55

Footnotes

1	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial secto consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 o http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.htm
2	Assumes 8,760 hour per year
3	Incremental electricity required to compensate for additional pressure drop of system is assumed to include additional ductwork (7"w.c.), and SCR catalyst bags (10"w.c.).
4	Power requirement calculated as specified in EPA Air Pollution Control Cost Manual, 6th Edition, Chapter 3.2, Equation 2.42, assuming 60% combined efficiency of the fan and motor.

Table A.5-4: NO_x Cost Analysis for Regenerative Selective Catalytic Reduction (RSCR): Direct-fired Rotary Calciner Nos.1 through 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
BPE Equipment Cost, RSCR Aqueous Ammonia NO_x Control System	$2,415,000	This cost is based upon BPE Proposal No. 502DDD, dated 1/8/09. This is an equipment-only proposal.
Purchased Equipment Cost (PEC)	**$2,415,000**	
Direct Installation Costs (DIC)		
Site Preparation	$1,266,384	See Table A.5-4a. Costs scaled using 6/10ths rule from 37,000 acfm quote for construction of a wet scrubber at CARBO McIntyre: Cost A = Cost B * (Capacity of A / Capacity of B)$^{0.6}$
Foundations and Supports	$718,242	
Electrical and Instrumentation	$235,713	See Table A.5-4a
Safety Systems and Equipment	$52,000	
Piping	$55,000	
Ductwork	$174,800	
Initial Spare Parts Inventory	$50,000	
Wastewater Treatment System	$1,150,000	
Total Direct Installation Costs (DIC)	**$3,702,138**	
Freight	$43,470	See Table A.5-4a
Total Direct Costs (TDC)	**$6,160,608**	**TDC=PEC+DIC+Freight**
Owner Provided Indirect Costs		
Engineering and Project Management	$262,000	See Table A.5-4a
Start-Up, Performance Test, and Training	$69,375	
Contractor Fees	$400,000	
Controls Integration	$100	
Cost of Lost Production	$525,000	
Contingency @ 40%	$2,756,833	
Total Indirect Costs (TIC)	**$4,013,308**	
Total Capital Cost (TCC)	**12,588,917**	**TCC=TDC+TIC**
Annual Cost		
Operating Labor	$32,220	Based on 3 shifts/day, 8,592 operating hours per year at $30/hr, and 1 labor hour/shift per the ACT Document, Ch. 6.1.3.2
Supervision Labor	$4,833	15% of Operating Labor Cost per the ACT Document, Table 6-3
Maintenance and Repair Parts	$881,375	Assumes annual repair parts at 7% of capital cost plus $151K annual expense for repair and replacement of catalyst; assumes 2-year catalyst life based on BPE catalyst warranty and concerns regarding potential catalyst poisons in flue gas
Cost of Lost Production for Annual Maintenance & Repair	$525,000	Assumes 1-week annual shutdown for maintenance
Electricity	$122,814	Incremental load is 344 HP (257kW assuming 0.746 kW/HP) at $0.056/kWh. 8,592 operating hours per year assumed.
Natural Gas	$45,160	Calculated based on BPE advised usage (5,256 Mscf) and cost of $8.76/Mscf. 8,592 operating hours per year assumed.
Reagent Chemicals	$845,210	Calculated based on information provided by BPE re usage and price from BPE for 19% aqueous ammonia reagent. 8,592 operating hours per year assumed.
Plant air and water	$4,356	Calculated based on BPE advised usage for water and air and County rates for water. 8,592 operating hours per year assumed.
Administrative and Insurance	$377,668	Assumes 3% of capital per the ACT Document, Table 6-3
Overhead	$528,825	60% of Maintenance per the ACT Document, Table 6-3
Capital Recovery Factor	14.24%	Calculated per the ACT Document, Chapter 6.1.3.8 using 7% interest (i) and 10 year life. CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery Cost/Year	$1,792,379	Total Capital Cost * Total Recovery Factor
Total Annual Cost, $	**$5,159,838**	
Annual Cost $ per Ton NO_x Removed	**$13,908**	Based on 530 tpy baseline and 70% control; 371 tons removed

Note (1):"The ACT Document" refers to EPA Document *Alternative Control Technoques Document - NO_x Emissions from Cement Manufacturing* (EPA-453/R-94-004)

Table A.5-4a: Detailed Budgetary Cost Analysis for Regenerative Selective Catalytic Reduction direct-fired Rotary Calciner Nos.1 through 4

Estimated by TMTS Associates based on a quote from Babcock Power Environmental for an RSCR system

Equipment	Cost From Vendor Quote	Notes	Source
Detailed Project Costs			
Direct Costs			
Purchased Equipment Cost (PEC)			
Total from BPE Lump Sum Price in Proposal	$2,415,000		This cost is based upon BPE Proposal date 1/8/09
Total Cost of PEC:	**$2,415,000**		
Site Preparation			
Site work, demolition, earth work	$920,200	McIntyre system's design flow rate is 37,000 acfm, so cost scaling will be conducted on that basis	Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility
Total Cost of Site Preparation:	**$920,200**		
Scaled Cost of Site Preparation:	**$1,266,384**		
Foundations & Supports			
Foundations & Supports	$521,900	McIntyre system's design flow rate is 37,000 acfm, so cost scaling will be conducted on that basis	Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility
Total Cost of Foundations/Supports:	**$521,900**		
Scaled Cost of Foundations/Supports:	**$718,242**		
Electrical and Instrumentation			
NO/NO_2 gas analyzer	$137,713	One (1) Horiba NO/NO_2 gas analyzer ENDA – 1300 Series, (CEMS) package, Model #ENOA-1390 with auto calibration, calibration flow path to meet EPA requirements for calibration gas at sample probe, weather resistant enclosure.	From File Quotation, Tri-Mer
Triboelectric Dust Detector	$23,000	Auburn Systems Tribo Series or equivalent, 4 sensors with ceramic tips into processor, with 4-20 mA output	File quote, Auburn
Associated Electrical Equipment not provided by BPE	$75,000	Includes MCC, motor starters, breakers, distribution panels, overload protection, and distribution wiring	Comparable Experience on other jobs
Total Cost of Elec. and Instr.:	**$235,713**		
Safety Systems and Equipment			
Showers/Eyewash Stations	$2,000	Assumes 2 combination ES/EW stations	Means Constr Cost Data
Safety Equipment	$50,000	Chemical splash suits, ambient air monitors, etc.	Comparable Experience on other jobs
Total Cost of Safety Systems:	**$52,000**		
Piping			
RSCR Piping materials	$42,000	Piping for RSCR system, Schedule 40, and hangers 10' OC, air, water, and drain piping, material portion	Means Constr Cost Data
Insulation and Freeze Protection materials	$13,000	Assumes ammonia lines, water line, and recirc lines, FG w/ASJ insulation and heat tracing, material portion	Means Constr Cost Data
Total Cost of Piping:	**$55,000**		
Ductwork			
Modifications and additions to existing plant exhaust system.	$29,000	Assumes 150 LF hot gas ductwork, material portion	Means Constr Cost Data (Further discussion may be necessary with plant re duct material.)
Ductwork for RSCR system	$108,000	Assumes hot gas ductwork and CEMS enclosure, material portion	Means Constr Cost Data
Duct Insulation	$37,800	Insulation, 2" thick, 1# density, FSK facing for ductwork, material portion	Means Constr Cost Data
Total Cost of Ductwork:	**$174,800**		

Table A.5-4a: Detailed Budgetary Cost Analysis for Regenerative Selective Catalytic Reduction direct-fired Rotary Calciner Nos.1 through 4

Estimated by TMTS Associates based on a quote from Babcock Power Environmental for an RSCR system

Equipment	Cost From Vendor Quote	Notes	Source
Initial Spare Parts Inventory			
Initial Spare Parts Inventory	$50,000	For RSCR system - not included in BPE proposal	Comparable Experience on other jobs
Total Cost of Spare Parts Inv.:	**$50,000**		
Wastewater Treatment System			
Wastewater treatment system and chemicals	$1,150,000	To build an adequate system for blowdown rate calculated based on BPE advised usage for water for the wash system.	-
Total Cost of WWT:	**$1,150,000**		
Freight			
Freight	$43,470		Based on 1.5% of BPE Equipment Cost plus a portion of non-BPE costs
Total Cost of Freight:	**$43,470**		
Total Direct Cost:	**$6,160,608**		
Indirect Costs			
Engineering and Project Management			
Detailed Design and Engineering Review of Detailed Design	$162,500		Comparable Experience on other jobs
Air Permit Application, Preparation and Processing	$10,000		Comparable Experience on other jobs
Building Permit	$1,000		Comparable Experience on other jobs
Stack Testing	$20,000		Comparable Experience on other jobs
Other Testing	$10,000		Comparable Experience on other jobs
Project Management	$58,500	Oversight of site preparation, equipment construction, and equipment startup	Comparable Experience on other jobs
Total Cost of Eng. & Proj. Mgt:	**$262,000**		
Start-Up, Performance Test, and Training			
Detailed Design Firm Assistance during start-up	$24,375		15% of Detailed Design Cost
APC Consultant Assistance during start-up	$45,000	200 hours at $200/hour for advance prep and on-site assistance plus $5k expenses	
Total Cost of Start-Up, PT, Training:	**$69,375**		
Contractor Fees			
Labor for Setting/Installation	$78,000	Including assembly, rigging, and anchor bolts/tie-downs	Comparable Experience on other jobs
Labor for Ductwork	$180,000	Labor portion ductwork and insulation	Means Constr Cost Data
Labor for Piping	$42,000	Labor portion, non-BPE supplied piping plus assembly of fittings, instrumentation, etc. supplied by BPE	Means Constr Cost Data and Based on comparable Experience on other jobs
Labor for Electrical	$100,000		Comparable Experience on other jobs
Total Cost of Labor:	**$400,000**		
Controls Integration			
Controls Integration	$100	Includes interfaces and enhancements, HMI/Graphics development, logic programming, BMS integration	Comparable Experience on other jobs
Total Cost of Controls Integration:	**$100**		
Subtotal Indirect Cost:	**$731,475**		
Contingency @ 40%	$2,756,833	Includes interfaces and enhancements, HMI/Graphics development, logic programming, BMS integration	Comparable Experience on other jobs
Lost Production During Installation	$525,000	Assumes construction takes one week longer with control equipment	
Total Indirect Cost:	**$4,013,308**		

Table A.5-5: Energy and Environmental Impact Summary for Direct Fired Rotary Calciners Nos. 1 through 4 (each)

	Resource Consumption			Energy Equivalents	
Control Technology	Water (MGD)[1]	Gas (Mscf/yr)[1]	Electricity (kWh/yr)[1]	Total Energy Consumed (MMBtu/yr)[2]	Total Energy Consumed (MMBtu/hr)[3]
NO_x Wet Scrubbing	0.108	0	2,490,227	8,499	0.970
SCR	0	132,599	702,530	137,649	15.7
Catalytic Baghouse	0	0	1,135,495	3,875	0.442
Regenerative SCR	0	5,155	2,204,913	12,784	1.46
Low NO_x Processing Technology	0	0	0	0	0

	Collateral Emissions					
Control Technology	NO_x (tpy)[4]	GHG (tpy CO_2e)[5]	CO (tpy)[6]	VOC (tpy)[7]	SO_2 (tpy)[8]	Total PM (tpy)[9,10]
NO_x Wet Scrubbing	0.000	0.000	0.000	0.000	0.000	0.000
SCR[11]	0.663	8,004	5.57	0.365	0.040	0.504
Catalytic Baghouse	0.000	0.000	0.000	0.000	0.000	0.000
Regenerative SCR[11]	0.077	311	0.217	0.014	0.002	0.020
Low NO_x Processing Technology	0.000	0.000	0.000	0.000	0.000	0.000

Notes	
1	Per cost-effectiveness calculation sheets.
2	Total Energy Consumed, MMBtu/yr = (Gas Consumption, Mscf/yr) / (1,000 Mscf/MMscf) * (1,020 MMBtu/MMscf) + (Electricity Consumption, kWh/year) * (3413 Btu-hr/kWh) / (10^6 Btu/MMBtu)
3	Total Energy Consumed, MMBtu/hr = (Total Energy Consumed, MMBtu/yr) / (8,760 hr/yr)
4	Estimated NO_x emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1, NO_x emissions from small uncontrolled boilers. NO_x tpy = (Gas Consumption, Mscf) * (1 Mscf/1000 MMscf) * (100 lb NO_x/MMscf) / (2000 lb/ton)
5	Estimated greenhouse gas (GHG) emissions from natural gas combustion in control device calculated using AP-42 emission factors, 5th Edition, Table 1.4-2. Combined GHG Emission Factor, lb CO_2e/MMscf = (120,000 lb CO_2/MMscf) * (CO_2 GWP =1) + (2.2 lb N_2O/MMscf) * (N_2O GWP=310) + (2.3 lb CH_4/MMscf) * (CH_4 GWP=21) GHG Emissions, tpy CO_2e = (Gas Consumption, Mscf) * (1 Mscf/1000 MMscf) * (GHG EF=120,730 lb CO_2e/MMscf) / (2000 lb/ton)
6	Estimated CO emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1. CO, tpy = (Gas Consumption, Mscf) * (1 Mscf/1000 MMscf) * (84 lb CO/MMscf) / (2000 lb/ton)
7	Estimated VOC emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. VOC, tpy = (Gas Consumption, Mscf) * (1 Mscf/1000 MMscf) * (5.5 lb VOC/MMscf) / (2000 lb/ton)
8	Estimated SO_2 emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. SO_2, tpy = (Gas Consumption, Mscf) * (1 Mscf/1000 MMscf) * (0.6 lb SO_2/MMscf) / (2000 lb/ton)
9	Estimated PM emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. PM, tpy = (Gas Consumption, Mscf) * (1 Mscf/1000 MMscf) * (7.6 lb PM/MMscf) / (2000 lb/ton)
10	Total PM includes filterables and condensables. All PM assumed to be <2.5 microns
11	NO_x created by the SCR's duct burner is also controlled by the catalyst. A 14.75 MMBtu/hr duct burner is required for proper temperature maintenance of catalyst.

Table A.6-1: NO_x BACT Cost Analysis for Wet NO_x Scrubbers: Spray Dryers Nos. 1 through 8 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Cost (PEC)	**$1,778,019**	See Table A.6-1a.
Direct Installation Costs (DIC)		
Site Preparation	$1,048,615	See Table A.6-1a.
Foundations & Supports	$594,732	
Electrical and instrumentation	$151,339	
Safety systems and equipment	$31,133	
Piping	$61,573	
Ductwork	$44,278	
Wastewater Treatment Plant (WWTP)	$0	Not Required
Total Direct Installation Cost (DIC)	**$1,931,669**	
Freight	$88,901	See Table A.6-1a.
Total Direct Cost (TDC)	**$3,798,589**	**TDC=(PEC+DIC+Freight)**
Indirect Costs		
Engineering	$215,161	See Table A.6-1a.
Startup/Performance testing/Training	$123,839	
Contractor Fees	$252,520	
Controls integration	$138,367	
Contingency @ 20%	$905,695	
Cost of Lost Production During Installation	$525,000	
Total Indirect Cost (TIC)	**$2,160,583**	
Total Capital Cost (TCC)	**$5,959,172**	**TCC= (TDC+TIC)**
Annual Cost		
Operating Labor	$16,425	Based on 3 shifts/day, 8,592 operating hours per year at $30/hr, and 1 labor hour/shift per the ACT Document, Ch. 6.1.3.2
Maintenance Labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per the ACT Document, Ch. 6.1.3.3
Supervisory Labor	$2,710	15% of Operating Labor per the ACT Document, Table 6-3
Reagent and Water	$281,023	From a vendor quote for a scrubber system with 1,054.5 tpy of controlled NO_x and Annual Reagent Cost of $9,057,186. Scaled down using ratio of controlled NO_x (i.e 32.72/1054.5).
Electricity	$117,099	Based on quote for a scrubber system with design flow rate of 85,000 acfm and incremental motor load of 465 HP. Motor load scaled down using "6/10th rule". Electricity rate is $0.056/kWh- Per Table 1.5-1b. 8,760 operating hours per year assumed.
Administrative and Insurance	$178,775	Assumes 3% of capital cost as documented in the ACT Document, Table 6-3
Maintenance Repair Parts	$415,102	From a vendor quote for a scrubber system with a design flow rate of 85,000 acfm and annual maintenance and repair costs of $600,000. Scaled down by ratio of flow rates using "6/10th rule".
Capital Recovery Factor	9.44%	Calculated using The ACT Document Chapter 6.1.3.8, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery	$562,504	Total Capital Cost * Capital Recovery Factor
Total Annualized Cost, $	**$1,591,705**	
Total Cost per ton NO_x controlled	**$48,648**	Based on 36.4 tpy baseline and 90% control; 32.7 tons removed

Note (1):"The ACT Document" refers to EPA Document *Alternative Control Techniques Document - NO_x Emissions from Cement Manufacturing* (EPA-453/R-94-004)

Table A.6-1a: Detailed Capital Cost Analysis for Wet Scrubbers

Except as noted, per TMTS's preliminary estimate for construction of Tri-Mer wet scrubber using RSMeans Construction Costing data (2007 Edition).
These details do not include the cost of the required wastewater treatment plant.
Unless otherwise noted, scaled costs are scaled from 85,000 acfm to 46,000 acfm using "6/10th rule"

Equipment	Cost From Vendor Quote	Notes	Source
Detailed Project Costs			
Direct Costs			
Purchased Equipment Cost (PEC)			
Total from Tri-Mer Lump Sum Price Quote	$2,570,000		Tri-Mer 4/9/07 quote
Total Cost of PEC:	**$2,570,000**		
Scaled Cost of PEC:	**$1,778,019**		
Site Preparation			
Site work, demolition, earth work	$920,200	McIntyre system's design flow rate is 37,000 acfm, so cost scaling will be conducted on that basis	Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility
Total Cost of Site Preparation:	**$920,200**		
Scaled Cost of Site Preparation:	**$1,048,615**		
Foundations & Supports			
Foundations & Supports	$521,900	McIntyre system's design flow rate is 37,000 acfm, so cost scaling will be conducted on that basis	Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility
Total Cost of Foundations & Supports:	**$521,900**		
Scaled Cost of Foundations & Supports:	**$594,732**		
Electrical and Instrumentation			
NO/NO_2 gas analyzer	$119,750	Optional add-on in quote	Tri-Mer 4/9/07 quote
Insulation and Freeze Protection	$26,000	Assumes chemical lines, water line, and recirc lines FG w/ASJ insulation and heat tracing	TMTS/RSMeans
Yard and Local Lighting	$73,000	Includes 18 pole mounted HPS at 40' high and 10 LPS area lights	TMTS/RSMeans
Total Cost of Electrical Equipment:	**$218,750**		
Scaled Cost of Electrical Equipment:	**$151,339**		
Safety Systems and Equipment			
Safety Equipment	$40,000	SCBA, acid suits, etc. and ambient air monitors	MSA Firehawk SCBA or Comparable
Showers/Eyewash Stations	$5,000	Assumes 6 combination ES/EW stations	TMTS/RSMeans
Total Cost of Safety Equipment:	**$45,000**		
Scaled Cost of Safety Equipment:	**$31,133**		
Piping			
Y basket strainers for recirculation systems	$6,000	Used 3" Y basket strainer, CPVC, quantity 10	West Coast Pump, Inc., on-line catalog
Liquid Flowmeters	$83,000	8 to 80 gph , 1/2" NPT flowmeter, quantity 20, CPVC	Omega, on-line brochure, 2x price for PVC model
Total Cost of Piping:	**$89,000**		
Scaled Cost of Piping:	**$61,573**		
Ductwork			
Integral and interconnecting 66" dia UV white PPE ductwork and I/O transitions for between quench and 4-stage Tri-NOx and blower assmy only	N/A	Incl. In Tri-Mer lump sum	-
Ductwork, hot gas in from plant to stage 1	$49,000	Assumes 200 LF hot gas ductwork, galvanized	TMTS/RSMeans
Non-Tri-Mer Equipment Ductwork	-	Installation cost is included in "Hot Gas Ductwork" line item above.	
Tri-Mer system Installation, Ductwork	N/A	Incl. In Tri-Mer lump sum	-
Stack	$15,000	Assumes 50 LF stack	TMTS/RSMeans
Total Cost of Ductwork:	**$64,000**		
Scaled Cost of Ductwork:	**$44,278**		
Wastewater Treatment			
Wastewater Treatment Plant (WWTP)	$13,110,948	Not Required	
Total Cost of Wastewater Treatment:	**$0**		
Scaled Cost of Wastewater Treatment:	**$0**		
Freight			
Freight	$128,500	Assumed to be 5% of PEC per table 6-2 of the ACT Document	
Total Cost of Freight:	**$128,500**		
Scaled Cost of Freight:	**$88,901**		
Total Direct Cost:	**$3,798,589**		

Table A.6-1a: Detailed Capital Cost Analysis for Wet Scrubbers

Except as noted, per TMTS's preliminary estimate for construction of Tri-Mer wet scrubber using RSMeans Construction Costing data (2007 Edition).
These details do not include the cost of the required wastewater treatment plant.
Unless otherwise noted, scaled costs are scaled from 85,000 acfm to 46,000 acfm using "6/10th rule"

Equipment	Cost From Vendor Quote	Notes	Source
Indirect Costs			
Engineering			
Detailed Design and Engineering Review of Detailed Design	$300,000		Comparable Experience on other jobs
Air Permit Application, Preparation and Processing	$10,000		Comparable Experience on other jobs
Building Permit	$1,000		Comparable Experience on other jobs
Total Cost of Engineering:	**$311,000**		
Scaled Cost of Engineering:	**$215,161**		
Start-Up/Performance Testing/Training			
Tri-Mer Assistance, Per Tri-Mer quote, allow 15 days plus travel time and T/L at $950/man day on job and $750/man day travel for 2 personnel	$42,000	Optional add-on in quote	Value of $42K was provided in Tri-Mer Proposal of 4/9/07
Design Firm Assistance during start-up	$45,000		15% of Detailed Design Cost
Wastewater and Air Pollution Control Consultant Assistance during start-up	$75,000		Comparable Experience on other jobs
Stack Testing	$12,000		Comparable Experience on other jobs
Other Testing	$5,000		Comparable Experience on other jobs
Total Cost of Start-Up:	**$179,000**		
Scaled Cost of Start-Up:	**$123,839**		
Contractor Fees			
Tri-Mer System Installation, Set/Install	N/A	Incl. In Tri-Mer lump sum	-
Non-Tri-Mer Equipment Setting/Installation	$10,000		Comparable Experience on other jobs
Non-Tri-Mer Equipment Piping, incl feed (air, water, and drain piping)	$75,000		Comparable Experience on other jobs
Tri-Mer System Installation, Electrical Feeds, Controls, and Interconnects	$200,000	Note that this is not included in Tri-Mer proposal scope.	Comparable Experience on other jobs
Tri-Mer System Installation, Piping	N/A	Incl. In Tri-Mer lump sum	-
Non-Tri-Mer Electrical, incl panels, mains/feeds, and disconnects	$80,000		Comparable Experience on other jobs
Total Cost of Contractor Fees:	**$365,000**		
Scaled Cost of Contractor Fees:	**$252,520**		
Controls Integration			
Controls Integration	$200,000	Includes HMI/Graphics development, logic programming, BMS integration	Comparable Experience on other jobs
Total Cost of Controls Integration:	**$200,000**		
Scaled Cost of Controls Integration:	**$138,367**		
Subtotal Indirect Cost:	**$729,887**		
Contingency @ 20%	$905,695	20% of sum of Total Direct Cost and Subtotal Indirect Costs due to technology not having been demonstrated in practice for this source category	
Lost Production During Installation	$525,000	Assumes construction takes one week longer with control equipment	
Total Indirect Cost:	**$2,160,583**		

Note (1): 6/10th rule: Cost A = Cost B * $(\text{Capacity of A / Capacity of B})^{0.6}$

Table A.6-2: NO_x Cost analysis for Selective Catalytic Reduction (SCR) Systems: Spray Dryers 1 through 8 (each)

Cost Element	Budget Amount	Basis/Comments
Capital Cost		
Direct Costs		
Capital Cost	$8,608,275	Calculated using "6/10th rule" and escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) PEC_1=[PEC_2 x (Gas $Flowrate_1$/Gas $Flowrate_2$)$^{0.6}$] * (1522.1/943.1) PEC_2 based on the ACT Document Table 6-1, Mode No. 5
Direct Installation Cost (DIC)	$3,873,724	45% Capital Cost Per the ACT Document, Chapter 6.1.2
Freight	$430,414	Assumed to be 5% of PEC per the ACT Document, Table 6-2
Total Direct Cost (TDC)	$12,912,413	
Indirect Costs		
Indirect Installation Cost(IIC)	$2,840,731	33% Capital Cost Per the ACT Document Chapter 6.1.2
Contingency @ 20%	$1,721,655	20% of PEC per the ACT Document, Chapter 6.1.2
Total Indirect Cost (TIC)	$4,562,386	
Total Capital Cost (TCC)	**$17,474,799**	
Annual Cost		
Operating Labor	$32,850	Based on 3 shifts/day, 8,760 operating hours per year at $30/hr, and a labor factor of 1 hour per/shift per the ACT Document, Ch. 6.1.3.2
Supervision Labor	$4,928	15% of Operating Labor per the ACT Document, Table 6-3
Ammonia Reagent	$13,284	AR_1=AR_2 x (Emissions $_1$ / Emissions $_2$) * (1522.1/943.1) (AR_2=$238,000, $Emissions_2$ = 240lbs/hr) Calculated from escalated ammonia reagent cost of model kiln from USEPA study, scaled down according to uncontrolled NO_x emission rates. Costs escalated using Marshal and Swift Annual Average Cost Index for 2nd Qtr. 2010.
Catalyst	$408,883	CT_1=CT_2 x (Gas $Flowrate_1$/Gas $Flowrate_2$) * (1522.1/943.1) (CT_2=$293,000, Gas $Flowrate_2$ = 53,200 dscfm) Estimated from catalyst cost of an SCR installed in a model cement kiln described in the ACT Document, Table 6-15
Energy Costs	$2,282,637	See Table A.6-2a
Catalyst Maintenance	$100,000	Twice a year at $50,000 for overhead costs incurred per maintenance event. This number is based on a discussion with a current facility with an SCR system installed.
Administrative and Insurance	$524,244	Assumes 3% of capital cost per the ACT Document, Table 6-3
Capital Recovery Factor	10.98%	Calculated using the ACT Document, Chapter 6.1.3.8, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery	$1,918,639	Total Capital Cost * Total Recovery Factor
Total Annualized Cost, $	**$5,285,465**	
Total Cost per ton NO_x controlled	**$161,543**	Based on 36.4 tpy baseline and 90% control; 32.7 tons removed

Note (1):"The ACT Document" refers to EPA Document *Alternative Control Techniques Document - NO_x Emissions from Cement Manufacturing* (EPA-453/R-94-004)

Table A.6-2a: NO_x BACT Energy Cost Analysis for Selective Catalytic Reduction: Spray Dryers 1 through 8 (each)

Gas flowrate:	45,000	[acfm]
Reference temperature:	77	[°F]
Inlet gas temperature (after baghouse):	180	[°F]
Gas flowrate:	37,754	[scfm]
Inlet gas density:[1]	0.062	[lb/acf]
Waste gas heat capacity:[2]	0.248	[Btu/lb-°F]
Output temperature to SCR catalyst:[3]	700	[°F]
Fuel heat of combustion:[4]	21,502	[Btu/lb]
Fuel density:[4]	0.041	[lb/ft^3]
Duct Heater Fuel Requirement:[5]	16.74	[lb/min]
Duct Heater Fuel Requirement:[6]	410.18	[scfm]
Total Gas Flowrate after Duct Heater:	38,164	[scfm]

	Average Unit Cost[7,8]	Fuel Required	No. Hours per Year[11]		
Duct Burner Natural Gas[9]	8.76 $/Mscf	24.61 Mscf/hr	8,592	$	1,852,353.22
Urea Decomposition Natural Gas[10]	8.76 $/Mscf	0.69 Mscf/hr	8,592	$	52,180.15
Total Annual Natural Gas Usage:	217,412 Mscf/yr			$	1,904,533.37
Incremental Electricity at ID Fan[12,13]	0.56 $/kWh	78 kW	8,592	$	373,964.33
Urea Decomposition Blower[13,14]	0.56 $/kWh	1 kW	8,592	$	4,139.50
Total Annual Electricity Usage:	678,822 kWh/yr			$	378,103.82

Footnotes

1	Based on ideal gas equation at waste gas exhaust temperature, assuming waste gas is principally air.
2	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996.
3	Minimum catalyst temperature specified in FuelTech quote
4	Burner fuel is assumed to be natural gas (as methane). Please refer to Table 2.14 of EPA 452/B-02-001 Section 3.2.
5	Duct burner fuel needed to sustain the required catalyst temperature of 700 °F: Fuel Required (lb/min)= (Inlet Gas Density, lb/acf) * (Gas flow rate, acfm) * [(Waste Gas Heat Capacity, Btu/lb·ºF) * (Output Temperature, ºF) – (Waste Gas Heat Capacity, Btu/lb·ºF) * (Inlet Temperature, ºF)] / (Fuel Heat of Combustion, Btu/lb)
6	Fuel Required (scfm) = Fuel Required (lb/min) / (Fuel Density, lb/ft^3)
7	Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
8	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial secto consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 o http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.htm
9	Duct heater is required to re-heat exhaust gas from maximum baghouse temperature (405ºF) to minimum catalyst temperature (700ºF); Fuel Required (Mscf/hr) = (Duct Heater Fuel Requirement, scfm)
10	Heat required for urea decomposition chamber to allow for decomposition of urea/air mixture to ammonia gas for SCR process based on burner size specified in vendor quote for 63,000 acfm system: Fuel Required (Mscf/hr) = (0.99 MMBtu/hr vendor quote) / (1.02 MMBtu/Mscf) * (60 min/hr) * (45,000 acfm) / (63,000 acfm)
11	Assumes 8,760 hour per year potential minus one week (7 days * 24 hours) annual downtime for system maintenance and repair.
12	Incremental electricity required to compensate for additional pressure drop of SCR system is assumed to include duct burner (1"w.c.), additional ductwork (7"w.c.), and SCR catalyst (2.5"w.c.).
13	Power requirement calculated as specified in EPA Air Pollution Control Cost Manual, 6th Edition, Chapter 3.2, Equation 2.42, assuming 60% combined efficiency of the fan and motor.
14	Based on 621 scfm downstream of urea decomposition chamber and 10"w.c. pressure for ammonia injection grid per vendor. Flow requirement scaled down from quoted system of 63,000 acfm controlled airflow to 45,000 acfm.

Table A.6-3: Energy and Environmental Impact Summary for Spray Dryers 1 through 8 (each)

	Resource Consumption			Energy Equivalents	
Control Technology	Water (MGD)[1]	Gas (Mscf/yr)[1]	Electricity (kWh/yr)[1]	Total Energy Consumed (MMBtu/yr)[2]	Total Energy Consumed (MMBtu/hr)[3]
NO_x Wet Scrubbing	0.007	0	2,102,322	7,175	0.819
SCR	0	217,412	678,822	224,078	25.6

	Collateral Emissions					
Control Technology	NO_x (tpy)[4]	GHG (tpy CO_2e)[5]	CO (tpy)[6]	VOC (tpy)[7]	SO_2 (tpy)[8]	Total PM (tpy)[9,10]
NO_x Wet Scrubbing	0.000	0.000	0.000	0.000	0.000	0.000
SCR[11]	1.09	13,124	9.13	0.598	0.065	0.826

Notes	
1	Per cost-effectiveness calculation sheets.
2	Total Energy Consumed, MMBtu/yr = (Gas Consumption, Mscf/yr) / (1,000 Mscf/MMscf) * (1,020 MMBtu/MMscf) + (Electricity Consumption, kWh/year) * (3413 Btu-hr/kWh) / (10^6 Btu/MMBtu)
3	Total Energy Consumed, MMBtu/hr = (Total Energy Consumed, MMBtu/yr) / (8,760 hr/yr)
4	Estimated NO_x emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1, NO_x emissions from small uncontrolled boilers. NO_x, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (100 lb NO_x/MMscf) / (2000 lb/ton)
5	Estimated greenhouse gas (GHG) emissions from natural gas combustion in control device calculated using AP-42 emission factors, 5th Edition, Table 1.4-2. Combined GHG Emission Factor, lb CO_2e/MMscf = (120,000 lb CO_2/MMscf) * (CO_2 GWP =1) + (2.2 lb N_2O/MMscf) * (N_2O GWP=310) + (2.3 lb CH_4/MMscf) * (CH_4 GWP=21) GHG Emissions, tpy CO_2e = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (GHG EF=120,730 lb CO_2e/MMscf) / (2000 lb/ton)
6	Estimated CO emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1. CO, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (84 lb CO/MMscf) / (2000 lb/ton)
7	Estimated VOC emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. VOC, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (5.5 lb VOC/MMscf) / (2000 lb/ton)
8	Estimated SO_2 emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. SO_2, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (0.6 lb SO_2/MMscf) / (2000 lb/ton)
9	Estimated PM emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. PM, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (7.6 lb PM/MMscf) / (2000 lb/ton)
10	Total PM includes filterables and condensables. All PM assumed to be <2.5 microns
11	NO_x created by the SCR duct burner is also controlled by the catalyst. A 25.1 MMBtu/hr duct burner is required for proper temperature maintenance of catalyst.

Table A.7-1: NO_x BACT Cost Analysis for Wet NO_x Scrubbers: Boilers Nos. 1 through 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Cost (PEC)	**$309,775**	See Table A.7-1a
Direct Installation Costs (DIC)		
Site Preparation	$182,694	See Table A.7-1a.
Foundations & Supports	$103,617	
Electrical and instrumentation	$26,367	
Safety systems and equipment	$5,424	
Piping	$10,728	
Ductwork	$7,714	
Wastewater Treatment Plant (WWTP)	$0	Not Required
Total Direct Installation Cost (DIC)	**$336,544**	
Freight	$15,489	See Table A.7-1a.
Total Direct Cost (TDC)	**$661,807**	**TDC=(PEC+DIC+Freight)**
Indirect Costs		
Engineering	$37,486	See Table A.7-1a.
Startup/Performance testing/Training	$21,576	
Contractor Fees	$43,995	
Controls integration	$24,107	
Contingency @ 20%	$157,794	
Cost of Lost Production During Installation	$525,000	
Total Indirect Cost (TIC)	**$809,959**	
Total Capital Cost (TCC)	**$1,471,766**	**TCC= (TDC+TIC)**
Annual Cost		
Operating Labor	$6,629	From a vendor quote for a scrubber system with a designed flowrate of 85,000 acfm. Cost scaled down using "6/10th rule"
Supervisory Labor	$994	15% of Operating Labor per the ACT Document, Table 6-3
Maintenance Labor	$14,464	From a vendor quote for a scrubber system with a designed flowrate of 85,000 acfm. Cost scaled down using "6/10th rule"
Maintenance Repair Parts	$72,321	From a vendor quote for a scrubber system with a design flow rate of 85,000 acfm and annual maintenance and repair costs of $600,000. Scaled down by ratio of flow rates using "6/10th rule".
Reagent and Water	$4,818	From a vendor quote for a scrubber system with 1,054.5 tpy of controlled NO_x and Annual Reagent Cost of $9,205,689. Scaled down using ratio of controlled NO_x (i.e 0.55/1054.5).
Electricity	$20,402	Based on quote for a scrubber system with design flow rate of 85,000 acfm and incremental motor load of 465 HP. Motor load scaled down using "6/10th rule". Electricity rate is $0.056/kWh-Per Table 7-1a. 8,760 operating hours per year assumed.
Administrative and Insurance	$44,153	Assumes 3% of capital cost as documented in the ACT Document, Table 6-3
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery	$138,924	Total Capital Cost * Capital Recovery Factor
Total Annualized Cost, $	**$302,706**	
Total Cost per ton NO_x controlled	**$548,499**	Based on 0.61 tpy baseline and 90% control; 0.55 tons removed

Table A.7-1a: Detailed Capital Cost Analysis for Wet Scrubbers

Except as noted, per TMTS's preliminary estimate for construction of Tri-Mer wet scrubber using RSMeans Construction Costing data (2007 Edition).
These details do not include the cost of the required wastewater treatment plant.
Unless otherwise noted, scaled costs are scaled from 85,000 acfm to 2,500 acfm using "6/10th rule"

Equipment	Cost From Vendor Quote	Notes	Source
Detailed Project Costs			
Direct Costs			
Purchased Equipment Cost (PEC)			
Total from Tri-Mer Lump Sum Price Quote	$2,570,000		Tri-Mer 4/9/07 quote
Total Cost of PEC:	**$2,570,000**		
Scaled Cost of PEC:	**$309,775**		
Site Preparation			
Site work, demolition, earth work	$920,200	McIntyre system's design flow rate is 37,000 acfm, so cost scaling will be conducted on that basis	Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility
Total Cost of Site Preparation:	**$920,200**		
Scaled Cost of Site Preparation:	**$182,694**		
Foundations & Supports			
Foundations & Supports	$521,900	McIntyre system's design flow rate is 37,000 acfm, so cost scaling will be conducted on that basis	Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility
Total Cost of Foundations & Supports:	**$521,900**		
Scaled Cost of Foundations & Supports:	**$103,617**		
Electrical and Instrumentation			
NO/NO2 gas analyzer	$119,750	Optional add-on in quote	Tri-Mer 4/9/07 quote
Insulation and Freeze Protection	$26,000	Assumes chemical lines, water line, and recirc lines FG w/ASJ insulation and heat tracing	TMTS/RSMeans
Yard and Local Lighting	$73,000	Includes 18 pole mounted HPS at 40' high and 10 LPS area lights	TMTS/RSMeans
Total Cost of Electrical Equipment:	**$218,750**		
Scaled Cost of Electrical Equipment:	**$26,367**		
Safety Systems and Equipment			
Safety Equipment	$40,000	SCBA, acid suits, etc. and ambient air monitors	MSA Firehawk SCBA or Comparable
Showers/Eyewash Stations	$5,000	Assumes 6 combination ES/EW stations	TMTS/RSMeans
Total Cost of Safety Equipment:	**$45,000**		
Scaled Cost of Safety Equipment:	**$5,424**		
Piping			
Y basket strainers for recirculation systems	$6,000	Used 3" Y basket strainer, CPVC, quantity 10	West Coast Pump, Inc., on-line catalog
Liquid Flowmeters	$83,000	8 to 80 gph , 1/2" NPT flowmeter, quantity 20, CPVC	Omega, on-line brochure, 2x price for PVC model
Total Cost of Piping:	**$89,000**		
Scaled Cost of Piping:	**$10,728**		
Ductwork			
Integral and interconnecting 66" dia UV white	N/A	Incl. In Tri-Mer lump sum	-
Ductwork, hot gas in from plant to stage 1	$49,000	Assumes 200 LF hot gas ductwork, galvanized	TMTS/RSMeans
Non-Tri-Mer Equipment Ductwork	-	Installation cost is included in "Hot Gas Ductwork" line item above.	
Tri-Mer system Installation, Ductwork	N/A	Incl. In Tri-Mer lump sum	-
Stack	$15,000	Assumes 50 LF stack	TMTS/RSMeans
Total Cost of Ductwork:	**$64,000**		
Scaled Cost of Ductwork:	**$7,714**		
Wastewater Treatment			
Wastewater Treatment Plant (WWTP)	$13,110,948	Not Required	
Total Cost of Wastewater Treatment:	**$0**		
Scaled Cost of Wastewater Treatment:	**$0**		

Table A.7-1a: Detailed Capital Cost Analysis for Wet Scrubbers

Except as noted, per TMTS's preliminary estimate for construction of Tri-Mer wet scrubber using RSMeans Construction Costing data (2007 Edition).
These details do not include the cost of the required wastewater treatment plant.
Unless otherwise noted, scaled costs are scaled from 85,000 acfm to 2,500 acfm using "6/10th rule"

Equipment	Cost From Vendor Quote	Notes	Source
Freight			
Freight	$128,500	Assumed to be 5% of PEC per table 6-2 of the ACT Document	
Total Cost of Freight:	**$128,500**		
Scaled Cost of Freight:	**$15,489**		
Total Direct Cost:	**$661,807**		
Indirect Costs			
Engineering			
Detailed Design and Engineering Review of Detailed Design	$300,000		Comparable Experience on other jobs
Air Permit Application, Preparation and Processing	$10,000		Comparable Experience on other jobs
Building Permit	$1,000		Comparable Experience on other jobs
Total Cost of Engineering:	**$311,000**		
Scaled Cost of Engineering:	**$37,486**		
Start-Up/Performance Testing/Training			
Tri-Mer Assistance, Per Tri-Mer quote, allow 15 days plus travel time and T/L at $950/man day on job and $750/man day travel for 2 personnel	$42,000	Optional add-on in quote	Value of $42K was provided in Tri-Mer Proposal of 4/9/07
Design Firm Assistance during start-up	$45,000		15% of Detailed Design Cost
Wastewater and Air Pollution Control Consultant Assistance during start-up	$75,000		Comparable Experience on other jobs
Stack Testing	$12,000		Comparable Experience on other jobs
Other Testing	$5,000		Comparable Experience on other jobs
Total Cost of Start-Up:	**$179,000**		
Scaled Cost of Start-Up:	**$21,576**		
Contractor Fees			
Tri-Mer System Installation, Set/Install	N/A	Incl. In Tri-Mer lump sum	-
Non-Tri-Mer Equipment Setting/Installation	$10,000		Comparable Experience on other jobs
Non-Tri-Mer Equipment Piping, incl feed (air, water, and drain piping)	$75,000		Comparable Experience on other jobs
Tri-Mer System Installation, Electrical Feeds, Controls, and Interconnects	$200,000	Note that this is not included in Tri-Mer proposal scope.	Comparable Experience on other jobs
Tri-Mer System Installation, Piping	N/A	Incl. In Tri-Mer lump sum	-
Non-Tri-Mer Electrical, incl panels, mains/feeds, and disconnects	$80,000		Comparable Experience on other jobs
Total Cost of Contractor Fees:	**$365,000**		
Scaled Cost of Contractor Fees:	**$43,995**		
Controls Integration			
Controls Integration	$200,000	Includes HMI/Graphics development, logic programming, BMS integration	Comparable Experience on other jobs
Total Cost of Controls Integration:	**$200,000**		
Scaled Cost of Controls Integration:	**$24,107**		
Subtotal Indirect Cost:	**$127,164**		
Contingency @ 20%	$157,794	20% of sum of Total Direct Cost and Subtotal Indirect Costs due to technology not having been demonstrated in practice for this source category	
Lost Production During Installation	$525,000	Assumes construction takes one week longer with control equipment	
Total Indirect Cost:	**$809,959**		

Note (1): 6/10th rule: Cost A = Cost B * (Capacity of A / Capacity of B)$^{0.6}$

Table A.7-2: NO_x Cost analysis for Selective Catalytic Reduction (SCR) Systems: Boilers 1 through 4 (each)

Cost Element	Budget Amount	Basis/Comments
Capital Cost		
Total Capital Cost	**$168,000**	Based on June 2008 budgetary cost estimate from TMTS Associates.
Annual Cost		
Supervision Labor	$0	Per EPA Cost Manual,Section 4.2, Chapter 2.4.1
Operating Labor	$0	
Maintenance Labor and Materials	$2,520	1.5% of the Total Capital Cost per EPA Cost Manual, Section 4.2, Chapter 2.4.1
Reagent Costs	$494	Calculated by TMTS Associates; 40% Urea for use with a 10 MMBtu/hr boiler at 0.75 lb/hr NO_x at $2,646/year; scaled down to 0.14 lb/hour emission rate
Air and Water Costs	$500	Calculated by TMTS Associates.
Electricity Costs	$3,659	Based on a 10 HP (7.5kW) incremental load per TMTS Associates and $0.056/kWh utility rate. 8,760 operating hours per year assumed.
Annual Replacement cost for Catalyst	$10,000	Estimated by TMTS Associates based on replacement of catalyst every 2 years.
Administrative and Insurance	$5,040	Assumes 3% of capital cost as documented in the ACT Document, Table 6-3
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery	$15,858	Total Capital Cost * Capital Recovery Factor
Total Annualized Cost, $	**$38,071**	
Total Cost per ton NO_x controlled	**$68,985**	Based on 0.61 tpy baseline and 90% control; 0.55 tons removed

Table A.7-3: NO_x Cost Analysis for Selective Non-Catalytic Reduction (SNCR) Systems: Boilers 1 through 4 (each)

Cost Element	Budget Amount	Basis/Comments
Capital Cost		
Total Capital Cost	**$384,000**	Based on June 2008 budgetary cost estimate from TMTS Associates.
Annual Cost		
Reagent Costs	$5,261	Calculated by TMTS Associates: 32.5% Urea
Air and Water Costs	$500	Calculated by TMTS Associates.
Electricity	$3,659	Based on a 10 HP (7.5kW) incremental load per TMTS Associates and $0.056/kWh utility rate. 8,760 operating hours per year assumed.
Supervision Labor	$36,135	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 1 hour per/shift
Operating Labor	$32,850	Based on 3 shifts/day, 8,760 operating hours per year at $30/hr, and a labor factor of 1 hour per/shift
Insurance and Administrative	$11,520	3% of Escalated TCC per ACT Document
Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery	$42,161	Total Capital Cost * Capital Recovery Factor
Total Annualized Cost, $	**$132,087**	
Total Cost per ton NO_x controlled	**$430,811**	Based on 0.61 tpy baseline and 50% control; 0.31 tons removed

Table A.7-4: Energy and Environmental Impact Summary for Boilers 1 through 4 (each)

Control Technology	Resource Consumption: Water (MGD)[1]	Resource Consumption: Gas (Mscf/yr)[1]	Resource Consumption: Electricity (kWh/yr)[1]	Energy Equivalents: Total Energy Consumed (MMBtu/yr)[2]	Energy Equivalents: Total Energy Consumed (MMBtu/hr)[3]
NOx Wet Scrubbing	0.0001	0	366,276	1,250	0.143
SCR	0	0	65,700	224	0.026
SNCR	0	0	65,700	224	0.026
Low NOx Processing Technology	0	0	0	0	0

Control Technology	Collateral Emissions: NO_x (tpy)[4]	GHG (tpy CO_2e)[5]	CO (tpy)[6]	VOC (tpy)[7]	SO_2 (tpy)[8]	Total PM (tpy)[9,10]
NOx Wet Scrubbing	0.000	0.000	0.000	0.000	0.000	0.000
SCR[11]	0.000	0.000	0.000	0.000	0.000	0.000
SNCR	0.000	0.000	0.000	0.000	0.000	0.000
Low NOx Processing Technology	0.000	0.000	0.000	0.000	0.000	0.000

Notes
1 Per cost-effectiveness calculation sheets.
2 Total Energy Consumed, MMBtu/yr = (Gas Consumption, Mscf/yr) / (1,000 Mscf/MMscf) * (1,020 MMBtu/MMscf)
+ (Electricity Consumption, kWh/year) * (3413 Btu-hr/kWh) / (10^6 Btu/MMBtu)
3 Total Energy Consumed, MMBtu/hr = (Total Energy Consumed, MMBtu/yr) / (8,760 hr/yr)
4 Estimated NO_x emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1, NO_x emissions from small uncontrolled boilers. NO_x tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (100 lb NO_x/MMscf) / (2000 lb/ton)
5 Estimated greenhouse gas (GHG) emissions from natural gas combustion in control device calculated using AP-42 emission factors, 5th Edition, Table 1.4-2.
Combined GHG Emission Factor, lb CO_2e/MMscf = (120,000 lb CO_2/MMscf) * (CO_2 GWP =1) + (2.2 lb N_2O/MMscf) * (N_2O GWP=310)
+ (2.3 lb CH_4/MMscf) * (CH_4 GWP=21)
GHG Emissions, tpy CO_2e = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (GHG EF=120,730 lb CO_2e/MMscf) / (2000 lb/ton)
6 Estimated CO emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1.
CO, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (84 lb CO/MMscf) / (2000 lb/ton)
7 Estimated VOC emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2.
VOC, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (5.5 lb VOC/MMscf) / (2000 lb/ton)
8 Estimated SO_2 emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2.
SO_2, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (0.6 lb SO_2/MMscf) / (2000 lb/ton)
9 Estimated PM emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2.
PM, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (7.6 lb PM/MMscf) / (2000 lb/ton)
10 Total PM includes filterables and condensables. All PM assumed to be <2.5 microns
11 NO_x created by the duct burner is also controlled by the catalyst

Table A.8-1: NO_x BACT Cost Analysis for Wet NO_x Scrubbers: Emergency Generators Nos. 1 through 4 (each)

Cost Element	Budget Amount	Comments
Capital Costs		
Direct Costs		
Purchased Equipment Cost (PEC)	**$947,165**	See Table A.8-1a.
Direct Installation Costs (DIC)		
Site Preparation	$558,606	See Table A.8-1a.
Foundations & Supports	$316,818	
Electrical and instrumentation	$80,620	
Safety systems and equipment	$16,585	
Piping	$32,801	
Ductwork	$23,587	
Wastewater Treatment Plant (WWTP)	$0	Not Required
Total Direct Installation Cost (DIC)	**$1,029,016**	
Freight	$47,358	See Table A.8-1a.
Total Direct Cost (TDC)	**$2,023,540**	**TDC=(PEC+DIC+Freight)**
Indirect costs		
Engineering	$114,618	See Table A.8-1a.
Startup/Performance testing/Training	$65,970	
Contractor Fees	$134,520	
Controls integration	$73,709	
Contingency @ 20%	$482,471	
Cost of Lost Production During Installat	$525,000	
Total Indirect Cost (TIC)	**$1,396,288**	
Total Capital Cost (TCC)	**$3,419,828**	TCC= (TDC+TIC)
Annual Costs		
Reagent and Water	$63,562	From a vendor quote for a scrubber system with 1,054.5 tpy of controlled NO_x and Annual Reagent Cost of $9,205,689. Scaled down using ratio of controlled NO_x (i.e 7.28/1054.5).
Electricity	$3,560	Based on quote for a scrubber system with design flow rate of 85,000 acfm and incremental motor load of 465 HP. Motor load scaled down using "6/10th rule". Electricity rate is $0.056/kWh. 500 operating hours per year assumed.
Maintenance Repair Parts	$221,128	From a vendor quote for a scrubber system with a design flow rate of 85,000 acfm and annual maintenance and repair costs of $600,000. Scaled down by ratio of flow rates using "6/10th rule".
Maintenance Labor	$1,031	Based on 3 shifts/day, 500 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 5.2, Table 1.4
Operating Labor	$938	Based on 3 shifts/day, 500 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 5.2, Table 1.4
Supervisory Labor	$140.6	15% of Operating Labor per EPA Cost Manual, Section 5.2, Table 1.4
Administrative and Insurance	$102,595	Assumes 3% of capital cost as documented in the ACT Document, Table 6 3
Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery	$375,479	Total Capital Cost * Capital Recovery Factor
Total Annualized Cost, $	**$768,434**	
Total Cost per ton NO_x controlled	**$105,540**	Based on 8.09 tpy baseline and 90% control; 7.28 tons removed

Table A.8-1a: Detailed Capital Cost Analysis for Wet Scrubbers

Except as noted, per TMTS's preliminary estimate for construction of Tri-Mer wet scrubber using RSMeans Construction Costing data (2007 Edition).
These details do not include the cost of the required wastewater treatment plant.
Unless otherwise noted, scaled costs are scaled from 85,000 acfm to 16,103 acfm using "6/10th rule"

Equipment	Cost From Vendor Quote	Notes	Source
Detailed Project Costs			
Direct Costs			
Purchased Equipment Cost (PEC)			
Total from Tri-Mer Lump Sum Price Quote	$2,570,000		Tri-Mer 4/9/07 quote
Total Cost of PEC:	**$2,570,000**		
Scaled Cost of PEC:	**$947,165**		
Site Preparation			
Site work, demolition, earth work	$920,200	McIntyre system's design flow rate is 37,000 acfm, so cost scaling will be conducted on that basis	Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility
Total Cost of Site Preparation:	**$920,200**		
Scaled Cost of Site Preparation:	**$558,606**		
Foundations & Supports			
Foundations & Supports	$521,900	McIntyre system's design flow rate is 37,000 acfm, so cost scaling will be conducted on that basis	Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility
Total Cost of Foundations & Supports:	**$521,900**		
Scaled Cost of Foundations & Supports:	**$316,818**		
Electrical and Instrumentation			
NO/NO2 gas analyzer	$119,750	Optional add-on in quote	Tri-Mer 4/9/07 quote
Insulation and Freeze Protection	$26,000	Assumes chemical lines, water line, and recirc lines FG w/ASJ insulation and heat tracing	TMTS/RSMeans
Yard and Local Lighting	$73,000	Includes 18 pole mounted HPS at 40' high and 10 LPS area lights	TMTS/RSMeans
Total Cost of Electrical Equipment:	**$218,750**		
Scaled Cost of Electrical Equipment:	**$80,620**		
Safety Systems and Equipment			
Safety Equipment	$40,000	SCBA, acid suits, etc. and ambient air monitors	MSA Firehawk SCBA or Comparable
Showers/Eyewash Stations	$5,000	Assumes 6 combination ES/EW stations	TMTS/RSMeans
Total Cost of Safety Equipment:	**$45,000**		
Scaled Cost of Safety Equipment:	**$16,585**		
Piping			
Y basket strainers for recirculation systems	$6,000	Used 3" Y basket strainer, CPVC, quantity 10	West Coast Pump, Inc., on-line catalog
Liquid Flowmeters	$83,000	8 to 80 gph , 1/2" NPT flowmeter, quantity 20, CPVC	Omega, on-line brochure, 2x price for PVC model
Total Cost of Piping:	**$89,000**		
Scaled Cost of Piping:	**$32,801**		
Ductwork			
Integral and interconnecting ductwork	N/A	Incl. In Tri-Mer lump sum	-
Ductwork, hot gas in from plant to stage 1	$49,000	Assumes 200 LF hot gas ductwork, galvanized	TMTS/RSMeans
Non-Tri-Mer Equipment Ductwork	-	Installation cost is included in "Hot Gas Ductwork" line item above.	
Tri-Mer system Installation, Ductwork	N/A	Incl. In Tri-Mer lump sum	-
Stack	$15,000	Assumes 50 LF stack	TMTS/RSMeans
Total Cost of Ductwork:	**$64,000**		
Scaled Cost of Ductwork:	**$23,587**		
Wastewater Treatment			
Wastewater Treatment Plant (WWTP)	$13,110,948	Not Required	
Total Cost of Wastewater Treatment:	**$0**		
Scaled Cost of Wastewater Treatment:	**$0**		

Table A.8-1a: Detailed Capital Cost Analysis for Wet Scrubbers

Except as noted, per TMTS's preliminary estimate for construction of Tri-Mer wet scrubber using RSMeans Construction Costing data (2007 Edition).
These details do not include the cost of the required wastewater treatment plant.
Unless otherwise noted, scaled costs are scaled from 85,000 acfm to 16,103 acfm using "6/10th rule"

Equipment	Cost From Vendor Quote	Notes	Source
	Freight		
Freight	$128,500	Assumed to be 5% of PEC per table 6-2 of the ACT Document	
Total Cost of Freight:	**$128,500**		
Scaled Cost of Freight:	**$47,358**		
Total Direct Cost:	**$2,023,540**		
	Indirect Costs		
	Engineering		
Detailed Design and Engineering Review of Detailed Design	$300,000		Comparable Experience on other jobs
Air Permit Application, Preparation and Processing	$10,000		Comparable Experience on other jobs
Building Permit	$1,000		Comparable Experience on other jobs
Total Cost of Engineering:	**$311,000**		
Scaled Cost of Engineering:	**$114,618**		
	Start-Up/Performance Testing/Training		
Tri-Mer Assistance, Per Tri-Mer quote, allow 15 days plus travel time and T/L at $950/man day on job and $750/man day travel for 2 personnel	$42,000	Optional add-on in quote	Value of $42K was provided in Tri-Mer Proposal of 4/9/07
Design Firm Assistance during start-up	$45,000		15% of Detailed Design Cost
Wastewater and Air Pollution Control Consultant Assistance during start-up	$75,000		Comparable Experience on other jobs
Stack Testing	$12,000		Comparable Experience on other jobs
Other Testing	$5,000		Comparable Experience on other jobs
Total Cost of Start-Up:	**$179,000**		
Scaled Cost of Start-Up:	**$65,970**		
	Contractor Fees		
Tri-Mer System Installation, Set/Install	N/A	Incl. In Tri-Mer lump sum	-
Non-Tri-Mer Equipment Setting/Installation	$10,000		Comparable Experience on other jobs
Non-Tri-Mer Equipment Piping, incl feed (air, water, and drain piping)	$75,000		Comparable Experience on other jobs
Tri-Mer System Installation, Electrical Feeds, Controls, and Interconnects	$200,000	Note that this is not included in Tri-Mer proposal scope.	Comparable Experience on other jobs
Tri-Mer System Installation, Piping	N/A	Incl. In Tri-Mer lump sum	-
Non-Tri-Mer Electrical, incl panels, mains/feeds, and disconnects	$80,000		Comparable Experience on other jobs
Total Cost of Contractor Fees:	**$365,000**		
Scaled Cost of Contractor Fees:	**$134,520**		
	Controls Integration		
Controls Integration	$200,000	Includes HMI/Graphics development, logic programming, BMS integration	Comparable Experience on other jobs
Total Cost of Controls Integration:	**$200,000**		
Scaled Cost of Controls Integration:	**$73,709**		
Subtotal Indirect Cost:	**$388,817**		
Contingency @ 20%	$482,471	20% of sum of Total Direct Cost and Subtotal Indirect Costs due to technology not having been demonstrated in practice for this source category	
Lost Production During Installation	$525,000	Assumes construction takes one week longer with control equipment	
Total Indirect Cost:	**$1,396,288**		

Note (1): 6/10th rule: Cost A = Cost B * (Capacity of A / Capacity of B)$^{0.6}$

Table A.8-2: NO_x BACT Cost analysis for Selective Catalytic Reduction (SCR) System: Emergency Generator Nos. 1 through 4 (each)

Cost Element	Budget Amount	Comments
Capital Costs		
Direct Costs:		
SCR System Cost	$360,706	Per EPA Cost Manual, Section 4.2, Equation 2.36 for a new boiler with a bypass installed in 1999 Dollars. Includes the capital cost for the initial charge of catalyst. Catalyst cost estimated at 240 $/ft3 for a ceramic Honeycomb catalyst.
SCR System Cost - Escalated	$493,401	Based on Marshall & Swift Equipment Cost Index for the second quarter of 2010 Escalated Biofilter cost = (M&S Index, 2nd Q 2010)/(M&S Index, 1998) * (SCR Cost, 1999 Dollars) M&S Index, 2nd Q 2010 = 1,461.3 M&S Index, 1999 = 1,068.3
Total Direct Costs (TDC)	$493,401	
Indirect Installation Costs:		
General Facilities	$24,670	Cost factor (0.05 * TDC) per EPA Cost Manual, Section 4.2, Table 2.5
Engineering and Home Office Fees	$49,340	Cost factor (0.10 * TDC) per EPA Cost Manual, Section 4.2, Table 2.5
Process Contingency	$24,670	Cost factor (0.05 * TDC) per EPA Cost Manual, Section 4.2, Table 2.5
Total Indirect Installation Costs (TIC)	$98,680	
Plant Costs:		
Project Contingency	$88,812	Cost factor (0.05 * (TDC+ TIC)) per EPA Cost Manual, Section 4.2, Table 2.5
Total Plant Cost (TPC)	$680,893	DCC + TIC + Project Contingency
Preproduction Cost	$13,618	Cost factor (0.02 * TPC) per EPA Cost Manual, Section 4.2, Table 2.5
Inventory Capital	$1,325	Section 4.2, Equation 2.44. Cost for ammonia stored at site, the first fill of the reagent tanks.
Total Capital Cost (TCC)	**$695,835**	**TCC= TDC+TIC+TPR+Preproduction Cost+Inventory Capital**
Annual Cost		
Maintenance	$10,438	Cost factor (0.015 * TCI) per EPA Cost Manual, Section 4.2, Equation 2.46
Reagent Solution Cost	$1,971	Per EPA Cost Manual, Section 4.2, Equation 2.47
Electricity	$85	As determined in Table A.8-2a
Operating Labor	$0	No additional operating labor required per EPA Cost Manual, Section 4.2, p.2-45
Supervisory Labor	$0	No additional supervisory labor required per EPA Cost Manual, Section 4.2, p.2-45
Catalyst Replacement Cost:	$0	Assuming 24,000 hour catalyst life and 20 year system life, no catalyst replacement needed life of the system
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery	$65,682	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$78,176**	
Total Cost per ton NOx controlled	**$10,737**	Based on 8.09 tpy baseline and 90% control; 7.28 tons removed

Table A.8-2a: NO_x BACT Energy Cost Analysis for Selective Catalytic Reduction (SCR): Emergency Generators 1 through 4 (each)

SCR Input Parameters

Gas Flowrate ($q_{fluegas}$):	16,103	[acfm]
Inlet Gas Temperature (T):	869	[F]
Equipment Heat Input Rate (Q_B):	17	[MMBtu/hr]
Fuel Sulfur Content (S):	0.05	[% by weight]
Ammonia Slip[1]:	10	[ppm]
Catalyst Volume[2]:	98	[ft^3]
Catalyst Area[3]:	16.8	[ft^2]
Nominal Height of Catalyst (h'_{layer})[4]:	3.1	[ft]
Number of Catalyst Layers (n_{layer})[5]:	2.00	
Height of a Catalyst Layer (h_{layer})[6]:	3.93	[ft]
Reactor Area[7]:	19.3	[ft^2]
Reactor Length[8]:	4.39	[ft]
Reactor height (h_{SCR})[9]:	41.78	[ft]

Potential Emissions

Potential NO_x Emissions:	32.36	[lb/hr]
Potential NO_x Emissions:	8.09	[tpy]
Potential NO_x Emissions (NO_x in):	1.90	[lb/MMBtu]
NO_x Reduction Efficiency (n_{NOx}):	0.9	
Tons NO_x Reduced:	7.3	[tpy]

Reagent Consumption

NH_3 Mass Flow rate[10]:	11.3	[lb/hr]
NH_3 Solution Mass Flow rate[11]:	39	[lb/hr]

Fuel Consumption

Inlet gas density:[18]	0.074	[lb/acf]
Waste gas heat capacity:[19]	0.248	[Btu/lb-°F]
Output temperature to SCR catalyst:[20]	572	[°F]
Fuel heat of combustion:[21]	137,000	[Btu/gal]
Duct Heater Fuel Requirement:[22]	1.07	[gal/min]

Reagent	Average Cost[12,13, 14]	Consumption[15,16, 17]	No. Hours per year	
Reagent Solution	0.101 $/lb	39 lb/hr	500	$1,971.04
Fuel				
Duct Burner Diesel Fuel	2.43 $/gal	63.98 gal/hr	250	$ 38,867.98
Total Annual Diesel Fuel Usage:		15,995 gal/yr		$ 38,867.98
Electricity				
NH_3 Vaporization	0.056 $/kWh	3.1 kW	500	$85.17
Fan Power	0.056 $/kWh	0.0 kW	500	$0.00
Total Annual Electricity Usage:		1,529.0 KWh/yr		$85.17

Footnotes

1	Per vendor quote on an SCR system for generators
2	Calculated as specified in Section 4.2, Equation 2.19 of EPA Cost Manual assuming one SCR reactor per equipment.
3	Calculated as specified in Section 4.2, Equation 2.25 of EPA Cost Manual.
4	Per EPA Cost Manual, Section 4.2, p. 2-38.
5	Calculated as specified in Section 4.2, Equation 2.28 of EPA Cost Manual and rounded to the nearest integer.
6	Calculated as specified in Section 4.2, Equation 2.29 of EPA Cost Manual.
7	Calculated as specified in Section 4.2, Equation 2.26 of EPA Cost Manual.
8	Calculated as specified in Section 4.2, Equation 2.27 of EPA Cost Manual
9	Calculated as specified in Section 4.2, Equation 2.31 of EPA Cost Manual assuming one empty catalyst layer for future installation of catalyst.
10	Calculated as specified in Section 4.2, Equation 2.11 and 2.32 of EPA Cost Manual.
11	Calculated as specified in Section 4.2, Equation 2.33 of EPA Cost Manual for a 29% aqueous ammonia solution.
12	Reagent solution cost for a 29% aqueous ammonia solution per EPA Cost Manual, Section 4.2.
13	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
14	Diesel fuel unit cost is the mean of the 3 years (2007-2009) of annual average ULSD price data available for industrial sector consumers in the Gulf Coast Region per US Dept. of Energy, Energy Information Administration; see http://www.eia.gov/dnav/pet/pet_pri_dist_dcu_R30_a.htm
15	Reagent consumption estimated per Section 4.2, Equation 2.47 of EPA Cost Manual
16	Ammonia vaporization power requirement estimated per Section 4.2, Equation 2.48 of EPA Cost Manual. Accounts for dilution air blower.
17	Fan power requirement omitted for emergency generators.
18	Based on ideal gas equation at waste gas exhaust temperature, assuming waste gas is principally ai
19	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 199€
20	Minimum catalyst temperature specified in FuelTech quot€
21	Heating value of diesel fuel
22	Duct burner fuel needed to sustain the required catalyst temperature of 700 °F Fuel Required (lb/min)= (Inlet Gas Density, lb/acf) * (Gas flow rate, acfm) * [(Waste Gas Heat Capacity, Btu/lb·°F) * (Output Temperature, °F) - (Waste Gas Heat Capacity, Btu/lb·°F) * (Inlet Temperature, °F)] / (Fuel Heat of Combustion, Btu/lt

Table A.8-3: Energy and Environmental Impact Summary for Emergency Generators 1 through 4 (each)

Control Technology	Resource Consumption				Energy Equivalents	
	Water (MGD)[1]	Gas (Mscf/yr)[1]	Diesel Fuel (gal/yr)[1]	Electricity (kWh/yr)[1]	Total Energy Consumed (MMBtu/yr)[2]	Total Energy Consumed (MMBtu/hr)[3]
NO_x Wet Scrubbing	0.002	0	0	63,923	218	0.436
SCR	0	0	15,995	0	2,191	4.38
Good Combustion Techniques	0	0	0	0	0	0

Control Technology	Collateral Emissions					
	NO_x (tpy)[4]	GHG (tpy CO_2e)[5]	CO (tpy)[6]	VOC (tpy)[7]	SO_2 (tpy)[8]	Total PM (tpy)[9,10]
NO_x Wet Scrubbing	0.000	0.000	0.000	0.000	0.000	0.000
SCR[11]	0.016	179	0.040	0.002	0.002	0.026
Good Combustion Techniques	0.000	0.000	0.000	0.000	0.000	0.000

Notes	
1	Per cost-effectiveness calculation sheets.
2	Total Energy Consumed, MMBtu/yr = (Gas Consumption, Mscf/yr) / (1,000 Mscf/MMscf) * (1,020 MMBtu/MMscf) + (Diesel Fuel Consumption, gal/year) * (140,000 Btu/gal) / (10^6 Btu/MMBtu)
3	Total Energy Consumed, MMBtu/hr = (Total Energy Consumed, MMBtu/yr) / (500 hr/yr)
4	Estimated NO_x emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1, NO_x emissions from small uncontrolled boilers. NO_x, tpy = (Fuel Consumption, gal) * (1 Kgal/1000 gal) * (20 lb NO_x/Kgal) / (2000 lb/ton)
5	Estimated greenhouse gas (GHG) emissions from diesel combustion in control device calculated using AP-42 emission factors, 5th Edition, Table 1.4-2. Combined GHG Emission Factor, lb CO_2e/kgal = (22,300 lb CO_2/kgal) * (CO_2 GWP =1) + (0.260 lb N_2O/kgal) * (N_2O GWP=310) + (2.3 lb CH_4/MMscf) * (CH_4 GWP=21) GHG Emissions, tpy CO_2e = (Fuel Consumption, gal) * (1 kgal/1000 gal) * (GHG EF=22,382 lb CO_2e/kgal) / (2000 lb/ton)
6	Estimated CO emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-1. CO, tpy = (Fuel Consumption, gal) * (1 kgal/1000 gal) * (5 lb CO/kgal) / (2000 lb/ton)
7	Estimated VOC emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-3. VOC, tpy = (Fuel Consumption, gal) * (1 kgal/1000 gal) * (0.200 lb VOC/kgal) / (2000 lb/ton)
8	Estimated SO_2 emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-1. SO_2, tpy = (Fuel Consumption, gal) * (1 kgal/1000 gal) * (142S lb SO_2/kgal) / (2000 lb/ton); S=sulfur content = 0.0015%
9	Estimated PM emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-1 and 1.3-2. PM, tpy = (Fuel Consumption, gal) * (1 kgal/1000 gal) * (3.3 lb PM/kgal) / (2000 lb/ton) Total PM E.F. = 3.3 (Filterable E.F=2.0 lb/kgal and condensable E.F.=1.3 lb/kgal)
10	Total PM includes filterables and condensables. All PM assumed to be <2.5 microns
11	NO_x created by the duct burner is also controlled by the catalyst

ATTACHMENT B

Detailed CO BACT Analysis

VOLUME II, ATTACHMENT B
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CO BACT- Gas-Fired Boiler Nos. 1 – 4 (each)

CO BACT- Diesel Fired Emergency Generator Nos. 1 – 4 (each)

B. Top-Down BACT Analysis: Carbon Monoxide (CO)

B.1 CO Review: Direct Fired Rotary Calciner Nos. 1 – 4

Carbon monoxide (CO) is emitted from the direct-fired rotary calciners due to incomplete oxidation of fuel. Pre-combustion control technology such as good combustion techniques was evaluated for control of CO emissions from four direct-fired rotary calciners, including optimization of the design, operation, and maintenance of the calciner and combustion system and its efficient operation. Additionally, post-combustion control technology such as Regenerative Thermal Oxidizer (RTO) and Catalytic Oxidizer were evaluated for control of CO emissions from the four direct-fired rotary calciners.

This analysis is based on baseline CO emissions of 24.7 lb/hr or 108 tpy. This emission rate has been selected based on engineering testing and dispersion modeling impact analyses.

<u>Step 1: Identify all control technologies</u>

In reviewing the BACT alternatives to control emissions of CO from the four direct-fired rotary calciners, applicable BACT determinations and permits for non-metallic mineral processing plants have been reviewed, as summarized in Table B.1-1 below.

Table B.1-1: Summary of CO Control Technology Determinations for Kilns and Calciners

Facility Name	Location	Agency	Data-base	Process Type[1]	Permit Date	Process Description	Controls / Type	Emisssion Limits/ Description
Eagle-Picher Filtration & Minerals, Inc.	Vale, OR	OR DEQ	RBLC	90.024	May-03	Dryer/ Calciner Natural Gas Fired	Good Combustion Control	19.7 lb/hr for 3 hr average
Eagle-Picher Filtration & Minerals, Inc.	Vale, OR	OR DEQ	RBLC	90.024	May-03	Dryer/ Calciner Natural Gas Fired	Good Combustion Control	21.4 lb/hr for 3 hr average
Dalitalia LLC	Muskogee, OK	OK DEQ	RBLC	90.008	Oct-05	Natural Gas-fired Kilns	Good Combustion Techniques	1.55 lb/ton
CARBO – Toomsboro	Toomsboro, GA	GA EPD	Title V Permit	90.017	Dec-09	Natural gas-fired Rotary Calciners	Good combustion techniques / PSD	24.7 lb/hr
CARBO – McIntyre	McIntyre, GA	GA EPD	Title V Permit	90.017	Dec-09	Natural gas-fired Rotary Calciners	Good combustion techniques / PSD	24.5 lb/hr

[1] 90.017 = Calciners & Dryers and Mineral Processing Facilities, 90.024 = Nonmetallic Mineral Processing (excludes 90.017), 90.008 = Clay and Fly Ash Sintering

As a consequence of our review, pre-combustion control technology such as Good Combustion Techniques and post-combustion control technologies such as Regenerative

Thermal Oxidation and Catalytic Oxidation have been considered as summarized in Table B.1-2 below.

Table B.1-2: Evaluated Control Options for CO Emissions – Direct-fired Rotary Calciners Nos. 1 – 4

Option No.	Control Technology
1	BPI RSCR System with CO Catalyst
2	Regenerative Thermal Oxidation
3	Catalytic Oxidation
4	Good Combustion Techniques

Option 1 - BPI RSCR system with CO Catalyst

RSCR, or Regenerative Selective Catalytic Reduction technology, combines Selective Catalytic Reduction with the regenerative heat-recovery technology sometimes used in thermal oxidizers. The Babcock Power Inc. (BPI) RSCR system uses specialized regenerative media for heat recuperation combined with a selective catalyst reduction (SCR) for NO_x control. The regenerative nature of this system allows it to be installed downstream from a particulate matter (PM) control device such as a baghouse, and carry out SCR reactions with significant reductions in exhaust gas re-heating requirements. The availability and/or feasibility of a CO catalyst as an add-on to the BPI RSCR NO_x control system was evaluated. It was assumed that that the CO catalyst add-on would use a specialized catalyst to facilitate reduction of CO in the flue gas stream upstream to the ammonia injection port required as integral to the NO_x BPI-RSCR control system.

Option 2 –Regenerative Thermal Oxidation (RTO)

Carbon Monoxide can be oxidized to carbon dioxide and water vapor at high temperatures (generally about 1800°F). Regenerative thermal oxidizer (RTOs) use direct contact heat exchangers made from a ceramic material which can tolerate the high temperatures needed to achieve ignition of the waste streams. The waste gas stream enters the first stone bed where the gas is heated to a desired combustion temperature, then subsequently enters the second stone bed where heat is released from combustion and is recovered and stored in the bed. The beds alternate so the waste gas enters the second bed first in order to heat up to the desired combustion temperature, with the system operating on an alternating cycle to recover up to 95%[1] of the thermal energy during oxidation. The control efficiency of an RTO, when properly maintained and operated, can be as high as 98%.[1] Although the use of an RTO has been found to be technically feasible in theory, our review indicates that an RTO has not been applied as a measure to control CO in this industry before. Thus, using an RTO on Direct-fired Rotary Calciner Nos. 1 – 4 would be considered experimental.

[1] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.2.1

Option 3 – Catalytic Oxidation

Catalytic oxidation is a post combustion control technique for reducing emissions of CO and hydrocarbons. A catalytic oxidation system is a passive reactor, which consists of a honeycomb grid of metal panels, typically coated with platinum or rhodium. The catalyst grid is placed in the exhaust where the optimum reaction temperature can be maintained (450°F – 1200°F). The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the flue gas stream. The catalyst serves to increase reaction rates, thereby enabling conversions to carbon dioxide at lower reaction temperatures than in thermal oxidizers. The catalyst itself is not consumed in the reaction, but merely acts as the surface agent that enables the chemical reactions to take place. The active component of most catalytic oxidation systems is platinum metal, which is applied over a metal or ceramic substrate. When properly operated and maintained, a catalytic oxidizer can achieve a control efficiency as high as 95%.[2] Although the use of a catalytic oxidizer has been found to be technically feasible in theory, there is no indication that it has ever been applied as a measure to control CO in the non-metallic mineral processing industry before, and it is generally not applied as widely as thermal oxidation due to its higher sensitivity to pollutant characteristics and process conditions. Thus, using a catalytic oxidizer on Direct-fired Rotary Calciner Nos. 1 – 4 would be considered experimental.

Option 4 – Good Combustion Techniques

Optimization of the design, operation, and maintenance of the calciner and combustion system is the primary mechanism available for lowering CO. This process is often referred to as combustion controls. The factors involved include continuous mixing of air and fuel in the proper proportions, appropriate residence time, suitable temperatures in the combustion chamber to ensure complete burning, and adequate turbulence in the combustion chamber to ensure good mixing. As a result of the optimum conditions for combustion, CO emissions are minimized.

However, the addition of excess air and maintenance of high combustion temperatures for control of CO can result in an increase in NO_x emissions. Consequently, the typical practice is to design the combustion system (specifically, the air/fuel mixture and calciner temperature) such that CO is reduced as much as possible without causing NO_x emissions to significantly increase. This includes maintaining the air/fuel ratios at specified design points, having the proper air and fuel condition at the burner, and maintaining the fans and dampers in proper working condition. Proper operation and maintenance of the calciner will help to minimize the formation and emission of CO by ensuring that the combustion system operates as designed.

[2] Per vendor experience and US EPA's <u>Air Pollution Control Cost Manual</u>, 6th Edition, January 2002, Section 3.2, Subsection 2.4, Step 5c

Step 2: Eliminate technically infeasible options

Option 1 - BPI RSCR system with CO Catalyst

CARBO Ceramics has conducted an in-depth assessment of the viability of the Babcock Power, Inc. (BPI) - Regenerative Selective Catalytic (RSCR) system for the control of NO_x on calciners at the facility. As discussed in the NO_x BACT review in Attachment A of this volume, the facility strongly believes that, in addition to being economically unreasonable, this technology is highly experimental and its sustained use for compliance applications has not been demonstrated. Based on site visits to BPI RSCR installations in New Hampshire and Vermont and evaluation of the other two (2) facilities with BPI RSCR equipment installed, the use of CO reduction catalyst on an RSCR system has never been installed, nor has the feasibility of an add-on to these types of systems been effectively demonstrated. The experimental nature of the RSCR system and its limited operating record has been previously discussed with GAEPD, as well as presented in the various memorandums and trip reports.[3] Since the RSCR system is believed to be experimental and economically burdensome, the addition of a CO reduction catalyst to the RSCR system is deemed as unproven and experimental, is not considered a viable option to control CO as part of the BACT analysis, and will not be discussed further in this review.

Step 3: Rank remaining control technologies by control effectiveness

Table B.1-3: Ranking of Control Technology – Direct-fired Rotary Calciners Nos. 1 – 4
Baseline Emissions = 108.2 tpy CO

Control Technology Ranking	Option #	Control Technology	Control Efficiency	CO Reductions (tpy)
1	2	Regenerative Thermal Oxidation	98%	106.0
2	3	Catalytic Oxidation	95%	102.8
3	4	Good Combustion Techniques	N/A	N/A

Step 4: Evaluate most effective controls and document results

Table B.1-4 and Table B.1-5 below summarize the energy, environmental, and economic impacts of all remaining control technologies.

[3] CARBO letter of February 9, 2009 to GAEPD Re: RSCR update with final assessment.

Table B.1-4: BACT Control Analysis – Direct-fired Rotary Calciners Nos. 1 – 4

						Change in Emissions[2]					
Option No.	Control Technology	Annualized Cost	Cost Effectiveness ($/ton)	Total Energy Consumed (MMBtu/yr)	Water Usage (MGD)	NO_x (tpy)	VOC (tpy)	**CO (tpy)**	GHG (tpy CO_2e)	SO_2 (tpy)	Total PM[1] (tpy)
1	Regenerative Thermal Oxidation	$1,718,166	$16,206	92,504	0	+4.49	+0.247	**-106.0**	+5,421	+0.027	+0.341
2	Catalytic Oxidation	$1,540,846	$14,992	70,637	0	+3.23	+0.178	**-102.8**	+3,902	+0.019	+0.246
3	Good Combustion Techniques	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A

[1] Total PM includes filterables and condensables. All PM assumed to be <2.5 microns.
[2] Calculated emissions detailed in Table B.5-3

Table B.1-5: Incremental Cost Effectiveness Analysis – Direct-fired Rotary Calciners Nos. 1 – 4

Control Alternative	CO Controlled (tpy)	CO Reduced (tpy)	Installed Capital Cost ($)	Annual Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost Effectiveness[1] ($/ton)
Regenerative Thermal Oxidizer	108	106.0	$2,446,464	$1,718,166	$16,206	$55,413
Catalytic Oxidizer	108	102.8	$2,001,290	$1,540,846	$14,992	$14,992
Good Combustion Techniques	N/A	N/A	N/A	N/A	N/A	N/A

[1] Incremental cost effectiveness is the difference in annualized cost for the control option versus the next most effective control option divided by the difference in emissions resulting from the respective alternatives.

As shown in the previous table, the estimated costs exceed the level of cost effectiveness at which the installation of add-on pollution control devices can be deemed reasonable. In addition, the resources and energy that would be required to operate the control technologies are not justified based on the corresponding impacts.

Step 5: Select BACT

In order to effectively control CO emissions from the four process Direct-fired Rotary Calciners (Emission Unit ID Nos. KLN1 – KLN4), Good Combustion Techniques with a CO emission limit of 24.7 lbs/hr is proposed as BACT. Table B.1-6 summarizes the BACT determination requirements being proposed for the four Direct-fired Rotary Calciners.

Table B.1-6: CO BACT Proposed for Direct-fired Rotary Calciner Nos. 1 – 4

Emission Unit ID Nos.	BACT Limit (each emission unit)
KLN1 – KLN4	The use of Good Combustion Techniques with a CO emission limit of 24.7 lbs/hr to control emissions from each Direct-fired Rotary Calciner.

B.2 CO Review: Spray Dryers Nos. 1 – 8

CO emissions are emitted from the spray dryers due to the combustion of natural gas as the result of incomplete thermal oxidation of the carbon contained within the fuel. Pre-Combustion control technology, such as good combustion techniques, including optimization of the design, operation, and maintenance of the dryer and combustion system and its efficient operation, and post-combustion control technologies, such as Regenerative Thermal Oxidizer (RTO) and Catalytic Oxidizer, were evaluated for control of CO emissions from the spray dryers.

This analysis is based on baseline CO emissions of 16.6 lb/hr or 72.7 tpy. This emission rate has been selected based on engineering testing and dispersion modeling impact analyses.

Step 1: Identify all control technologies

In reviewing the BACT alternatives to control emissions of CO from spray dryers, all applicable BACT determinations and permits for non-metallic mineral processing plants have been reviewed, as summarized in Table B.2-1 below.

Table B.2-1: Summary of CO Control Technology Determinations for Spray Dryers

Facility Name	Location	Agency	Data-base	Process Type[1]	Permit Date	Process Description	Controls / Type	Emisssion Limits/ Description
Dalitalia Llc	Muskogee, OK	OK DEQ	RBLC	90.017	Oct-05	Natural gas-fired Spray Dryers	Good Combustion Techniques	0.366 lb/ton
CARBO – Toomsboro	Toomsboro, GA	GA EPD	Title V Permit	90.017	Dec-09	Natural gas-fired Spray Dryers	Good combustion techniques / PSD	16.6 lb/hr
CARBO– McIntyre	McIntyre, GA	GA EPD	Title V Permit	90.017	Dec-09	Natural gas-fired Spray Dryers	Good combustion techniques / PSD	13.8 lb/hr

[1] 90.017 = Calciners & Dryers and Mineral Processing Facilities

As a consequence of our review, pre-combustion control technology, such as good combustion techniques, and post-combustion control technologies, such as Regenerative Thermal Oxidation and Catalytic Oxidation, have been considered as summarized in Table B.2-2 below:

Table B.2-2: Evaluated Control Options for CO Emissions – Spray Dryers Nos. 1 – 8

Option No.	Control Technology
1	Regenerative Thermal Oxidation
2	Catalytic Oxidation
3	Good Combustion Techniques

Option 1 – Regenerative Thermal Oxidation (RTO)

Carbon Monoxide can be oxidized to carbon dioxide and water vapor at high temperatures (generally about 1800°F). Regenerative thermal oxidizers (RTOs) use direct contact heat exchangers made from a ceramic material which can tolerate the high temperatures needed to achieve ignition of the waste streams. The waste gas stream enters the first bed where the gas is heated to a desired combustion temperature, then subsequently enters the second stone bed where heat is released from combustion and is recovered and stored in the bed. The beds alternate so the waste gas enters the second bed first in order to heat up to the desired combustion temperature, with the system operating on an alternating cycle to recover up to 95%[4] of the thermal energy during oxidation. The control efficiency of an RTO, when properly maintained and operated, can be as high as 98%.[4] Although the use of an RTO has been found to be technically feasible in theory, our review indicates that an RTO has not been applied as a measure to control CO in the non-metallic mineral processing industry before. Thus, using an RTO on Spray Dryers Nos. 1 – 8 would be considered experimental.

Option 2 – Catalytic Oxidation

Catalytic oxidation is a post combustion control technique for reducing emissions of CO and hydrocarbons. A catalytic oxidation system is a passive reactor, which consists of a honeycomb grid of metal panels, typically coated with platinum or rhodium. The catalyst grid is placed in the exhaust where the optimum reaction temperature can be maintained (450°F – 1200°F). The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the flue gas stream. The catalyst serves to increase reaction times, thereby enabling conversions to carbon dioxide at lower reaction temperatures than in thermal oxidizers. The catalyst itself is not consumed in the reaction, but merely acts as the surface agent that enables the chemical reactions to take place. The active component of most catalytic oxidation systems is platinum metal, which is applied over a metal or ceramic substrate. When properly operated and maintained, a catalytic oxidizer can achieve a control efficiency as high as 95%.[5] Although the use of a catalytic oxidizer has been found to be technically feasible in theory, there is no indication that it has ever been applied as a measure to control CO in this industry before, and it is generally not applied as widely as thermal oxidation because of its higher sensitivity to pollutant characteristics and process conditions. Thus, using a catalytic oxidizer on Spray Dryers Nos. 1 – 8 would be considered experimental.

[4] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.2.1
[5] Per vendor experience and US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.4

Option 3- Good Combustion Techniques

Optimization of the design, operation, and maintenance of the dryers and combustion system is the primary mechanism available for lowering CO. This process is often referred to as combustion controls. The factors involved include continuous mixing of air and fuel in the proper proportions, appropriate residence time, suitable temperatures in the combustion chamber to ensure complete burning, and adequate turbulence in the combustion chamber to ensure good mixing. As a result of the optimum conditions for combustion, CO emissions are minimized.

However, the addition of excess air and maintenance of high combustion temperatures for control of CO can result in an increase in NO_x emissions. Consequently, the typical practice is to design the combustion system (specifically, the air/fuel mixtures and dryer temperatures) such that CO is reduced as much as possible without causing NO_x emissions to increase significantly. This includes maintaining the air/fuel ratios at specified design points, having the proper air and fuel condition at the burner, and maintaining the fans and dampers in proper working condition.

Step 2: Eliminate technically infeasible options

All the above technologies are deemed technically feasible.

Step 3: Rank remaining control technologies by control effectiveness

Table B.2-3: Ranking of Control Technology – Spray Dryers Nos. 1 – 8
Baseline Emissions = 72.7 tpy CO

Control Technology Ranking	Option No.	Control Technology	Control Efficiency	CO Reductions (tpy)
1	1	Regenerative Thermal Oxidation	98%	71.3
2	2	Catalytic Oxidation	95%	69.1
3	3	Good Combustion Techniques	N/A	N/A

Step 4: Evaluate most effective controls and document results

Table B.2-4 below summarize the energy, environmental, and economic impacts of all remaining control technologies

Table B.2-4: BACT Control Analysis – Spray Dryers Nos. 1 – 8

						Change in Emissions[2]					
Option No.	Control Technology	Annualized Cost	Cost Effectiveness ($/ton CO Reduced)	Total Energy Consumed (MMBtu/yr)	Water Usage (MGD)	NO_x (tpy)	VOC (tpy)	**CO (tpy)**	GHG (tpy CO_2e)	SO_2 (tpy)	Total PM[1] (tpy)
1	Regenerative Thermal Oxidation	$1,169,070	$16,407	97,476	0	+4.73	+0.260	**-71.3**	+5,715	+0.028	+0.360
2	Catalytic Oxidation	$1,175,265	$17,015	97,995	0	+4.57	+0.251	**-69.1**	+5,519	+0.027	+0.347
3	Good Combustion Techniques	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A

[1] Total PM includes filterables and condensables. All PM assumed to be <2.5 microns.
[2] Calculated emissions detailed in Table B.6-3

As shown in the previous table, the estimated costs exceed the level of cost effectiveness at which the installation of add-on pollution control devices can be deemed reasonable. In addition, the resources and energy that would be required to operate the control technologies are not justified based on the corresponding impacts.

Step 5: Select BACT

In order to effectively control CO emissions from the four Spray Dryers (Emission Unit ID Nos. SD01 – SD08), Good Combustion Techniques with a CO emission limit of 16.6 lbs/hr is proposed as BACT. Table B.2-5 summarizes the BACT determination requirements being proposed for the spray dryers.

Table B.2-5: CO BACT Proposed for Spray Dryer Nos. 1 – 8

Emission Unit ID Nos.	BACT Limit (each emission unit)
SD01 – SD08	The use of Good Combustion Techniques with a CO emission limit of 16.6 lbs/hr to control emissions from each Spray Dryer.

B.3 CO Review: Gas Fired Boilers Nos. 1 – 4

The facility is proposing to install four gas-fired boilers, each with a maximum heat input of 9.8 MMBtu/hr. CO emissions are emitted from the boilers due to the combustion of natural gas as the result of incomplete thermal oxidation of the carbon contained within the fuel. Pre-combustion control technology, such as good combustion techniques, including optimization of the design, operation, and maintenance of the boiler and combustion system and its efficient operation, as well as Post-Combustion control technologies, such as Recuperative Thermal Oxidizer and Catalytic Oxidizer, were evaluated for control of CO emissions from the gas-fired boilers.

This analysis is based on baseline CO emissions of 0.807 lb/hr or 3.53 tpy. This emission rate has been selected based on AP-42 factors and dispersion modeling impact analyses.

Step 1: Identify all control technologies

In reviewing the BACT alternatives to control emissions of CO from boilers, all applicable BACT determinations and permits for commercial and institutional size boilers and furnaces have been reviewed, as summarized in Table B.3-1 below.

Table B.3-1: Summary of CO Control Technology Determinations for Gas Fired Boilers

Facility Name	Location	Agency	Data-base	Permit Date	Process Description[1]	Controls / Type	Emisssion Limits/ Description
Wisconsin Public Service	Marathon, WI	WI DNR	RBLC	Aug-04	Natural Gas Fired Boiler	Boiler Design	1.67 lb/hr 0.036 lb/MMBtu
Duke Energy Hanging Rock, LLC	Ironton, OH	OH-EPA	RBLC	Dec-04	30.6 MMBtu/Hr Natural Gas Fired Boilers (2) each	None Specified	1.13 lb/hr 1.65 ton per 12-mo rolling period 0.037 lb/MMBtu
Nukor Steel	Hickman, AR	ADEQ	RBLC	Apr-06	12.6 MMBtu/Hr Natural Gas Fired Boilers each	Good Combustion Practice	3.2 lb/hr 13.9 tpy 0.084 lb/MMBtu
Cottage Health Care – Pueblo Street	Santa Barbara, CA	CA EPA	RBLC	May-06	25.0 MMBtu/Hr Natural Gas Fired Boilers (3) each	Ultra-low NO_x Burner	50.0 ppmv, 3% O_2 6 minute average 0.0607 lb/MMBtu[2]
Harrah's Operating Company, Inc.	Clark, NV	Clark Co. DEQ	RBLC	Jan-07	35.4 MMBtu/Hr Natural Gas Fired Boilers (2) each	Good Combustion Design	49.0 ppmvd, 3% O_2 0.036 lb/MMBtu
Daimler Chrysler Corporation – Toledo Supplier Park Paint Shop	Lucas, OH	OH-EPA	RBLC	May-07	20.4 MMBtu/Hr Natural Gas Fired Boilers (2) each	None Specified	1.7 lb/hr 7.5 tpy 0.083 lb/MMBtu
Associative Electric Cooperative, Inc – Chouteau Power Plant	Chouteau, OK	OK DEQ	RBLC	Jan-09	33.5 MMBtu/Hr Natural Gas Fired Boiler	Good Combustion Techniques	5.02 lb/hr 0.15 lb/MMBtu[2]
Flopam, Inc	Iberville Parish, LA	LA DEQ	RBLC	June-10	25.1 MMBtu/Hr Natural Gas Fired Boiler	Good Equipment Design and Proper Combustion Practices	0.930 lb/hr 0.037 lb/MMBtu

[1]All Processes are type 13.310, external combustion of natural gas <100 MMBtu/hr
[2]Implied emission rate calculated by Smith Aldridge to facilitate comparison across determinations

As a consequence of our review, pre-combustion control technology, such as Good Combustion Techniques, and post-combustion control technologies such as Regenerative

Thermal Oxidation and Catalytic Oxidation have been considered as summarized in Table B.3-2 below:

Table B.3-2: Evaluated Control Options for CO Emissions – Boilers Nos. 1 – 4

Option No.	Control Technology
1	Recuperative Thermal Oxidation
2	Catalytic Oxidation
3	Good Combustion Techniques

Option 1 –Recuperative Thermal Oxidation

Carbon Monoxide can be oxidized to carbon dioxide and water vapor at high temperatures (generally about 1800°F). Although thermal oxidizers can recover heat energy using recuperative or regenerative methods, and regenerative thermal oxidizers can achieve a much higher heat recovery rate than recuperative thermal oxidizers, the cost correlations for regenerative thermal oxidizers provided in US EPA's Cost Manual[6] are only considered applicable to flue gas flow rates 10,000-100,000 scfm. As Boilers 1 through 4 each have an exhaust gas flow rate of 1,600 scfm, recuperative thermal oxidation, valid for flue gas flow rates of 500-50,000 scfm, has been analyzed for cost effectiveness.

In a recuperative thermal oxidizer, the exhaust air is preheated by means of a heat exchanger before entering the combustion chamber. The hot exhaust from the combustion chamber is then fed through the other side of the heat exchanger to provide the preheating of intake air. Through this means, up to 70%[6] of the heat energy of the exhaust gas can be recovered, allowing for a reduction in fuel consumption. While this degree of heat recovery is less than is possible using the regenerative mechanism, the capital cost of the recuperative design can be substantially lower, which can, in some cases, offset the additional fuel consumption of the recuperative design.

The use of Regenerative Thermal Oxidizers to control CO from the gas-fired boilers is deemed technically feasible. The control efficiency of a Recuperative Thermal Oxidizer can be as high as 98%.[6]

Option 2 – Catalytic Oxidation

Catalytic oxidation is a post combustion control technique for reducing emissions of CO and hydrocarbons. A catalytic oxidation system is a passive reactor, which consists of a honeycomb grid of metal panels, typically coated with platinum or rhodium. The catalyst grid is placed in the exhaust where the optimum reaction temperature can be maintained (450°F – 1200°F). The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia necessary in NO_x catalysis) into the flue gas stream. The catalyst serves to increase reaction times, thereby enabling conversions to carbon dioxide at lower reaction temperatures than in thermal oxidizers. The catalyst itself is not consumed in the reaction, but merely acts as the surface agent

[6] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.2.1

that enables the chemical reactions to take place. The active component of most catalytic oxidation systems is platinum metal, which is applied over a metal or ceramic substrate. When properly operated and maintained, a catalytic oxidizer can achieve a control efficiency as high as 95%.[7] Although the use of a catalytic oxidizer has been found to be technically feasible in theory, there is no indication that it has ever been applied as a measure to control CO in this industry before, and it is generally not applied as widely as thermal oxidation because of its higher sensitivity to pollutant characteristics and process conditions. The use of a Catalytic Oxidizer to control CO from the gas-fired boilers is deemed technically feasible.

Option 3- Good Combustion Techniques

Optimization of the design, operation, and maintenance of the boilers and combustion system is the primary mechanism available for lowering CO. This process is often referred to as combustion controls. The factors involved include continuous mixing of air and fuel in the proper proportions, appropriate residence time, suitable temperatures in the combustion chamber to ensure complete burning, and adequate turbulence in the combustion chamber to ensure good mixing. As a result of the optimum conditions for combustion, CO emissions are minimized.

However, the addition of excess air and maintenance of high combustion temperatures for control of CO can result in an increase in NO_x emissions. Consequently, the typical practice is to design the combustion system (specifically, the air/fuel mixture and boiler temperature) such that CO is reduced as much as possible without causing NO_x emissions to increase significantly. This includes maintaining the air/fuel ratio at the specified design point, having the proper air and fuel condition at the burner, and maintaining the fans and dampers in proper working condition.

Step 2: Eliminate technically infeasible options

All the above technologies are deemed technically feasible.

Step 3: Rank remaining control technologies by control effectiveness

Table B.3-3: Ranking of Control Technology – Boilers Nos. 1 – 4
Baseline Emissions = 3.53 tpy CO

Control Technology Ranking	Option No.	Control Technology	Control Efficiency	CO Reductions (tpy)
1	1	Recuperative Thermal Oxidation	98%	3.46
2	2	Catalytic Oxidation	95%	3.35
3	3	Good Combustion Techniques	N/A	N/A

[7] Per vendor experience and US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.4

Step 4: Evaluate most effective controls and document results

Table B.3-4 below summarize the energy, environmental, and economic impacts of all remaining control technologies.

Table B.3-4: BACT Control Analysis – Boilers Nos. 1 – 4

						Change in Emissions[2]					
Option No.	Control Technology	Annualized Cost	Cost Effectiveness ($/ton CO Reduced)	Total Energy Consumed (MMBtu/yr)	Water Usage (MGD)	NO_x (tpy)	VOC (tpy)	**CO (tpy)**	GHG (tpy CO_2e)	SO_2 (tpy)	Total PM[1] (tpy)
1	Recuperative Thermal Oxidation	$205,354	$59,361	8,284	0	+0.404	+0.022	**-3.46**	+488	+0.002	+0.031
2	Catalytic Oxidation	$147,518	$43,989	3,074	0	+0.141	+0.008	**-3.35**	+170	+0.001	+0.011
3	Good Combustion Techniques	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A

[1] Total PM includes filterables and condensables. All PM assumed to be <2.5 microns.
[2] Calculated emissions detailed in Table B.7-3

As shown in the previous table, the estimated costs exceed the level of cost effectiveness at which the installation of add-on pollution control devices can be deemed reasonable. In addition, the resources and energy that would be required to operate the control technologies are not justified based on the corresponding impacts.

Step 5: Select BACT

In order to effectively control CO emissions from the four Gas Fired Boilers (Emission Unit ID Nos. BLR1 – BLR4) the use of Good Combustion Techniques is proposed as BACT. Table B.3-5 summarizes the BACT determination being proposed for the Gas Fired Boilers.

Table B.3-5: CO BACT Proposed for Gas Fired Boilers Nos. 1 – 4

Emission Unit ID Nos.	BACT
BLR1 – BLR4	The use of good combustion techniques

B.4 CO Review: Emergency Generators Nos. 1 – 4

The facility is proposing to install four (4) diesel-fired emergency generators rated at 2,280 kW (3,058 bhp) each. CO emissions are emitted from the diesel-fired emergency generators due to the combustion of diesel as the result of incomplete thermal oxidation of the carbon contained within the fuel. The units will be manufacturer-certified as compliant with the New Source Performance Standard (NSPS) requirements of 40 CFR 60, Subpart IIII emission standards for stationary compression-ignition engines. These standards already require dramatic reductions in CO emissions relative to the emissions of pre-2007 engines, and are the basis for the CO BACT baseline of 2.6 g/hp-hr.

Pre-Combustion control technology, such as good combustion techniques, including optimization of the design, operation, and maintenance of the engine and its fuel system and its efficient operation, and post-combustion control technologies, such as Recuperative Thermal Oxidizer and Catalytic Oxidizer, were evaluated for control of CO emissions from the four (4) new Diesel Fired Emergency Generators.

This analysis is based on baseline CO emissions of 17.5 lb/hr or 4.38 tpy. This emission rate has been selected based on EPA Tier II Standards and dispersion modeling impact analyses.

<u>Step 1: Identify all control technologies</u>

In reviewing the BACT alternatives to control emissions of CO from emergency generators, all applicable BACT determinations and permits for Diesel Fired Internal Combustion Engines of comparable ratings have been reviewed, as summarized in Table B.4-1 below.

Table B.4-1: Summary of CO Control Technology Determinations for Emergency Diesel Generators

Facility Name	Location	Data-base	Process Type[1]	Permit Date	Process Description	Controls / Type	Emission Limits/description		Emission Limit g/hp-hr Equivalent (g/hp-hr)	Comments
Maidsville	Monongahela, WV	RBLC	17.11	Mar-04	Emergency generator	Good combustion practices	8.85	lbs/hr	–	Limits in g/hp-hr not specified. The engines at the CARBO Ceramics facility will satisfy the federal engine standards of 40 CFR 89 for their respective year of purchase.
Arizona Clean Fuels Yuma, LLC	Pheonix, AZ	RBLC	17.11	Apr-05	Diesel Emergency Generator rated at 10.9 MMBtu/hr	None indicated	3.5	g/kW-hr	2.61	Equivalent to Tier II standard per 40 CFR 89.
Marathon Petroleum Co., LLC – Garyville Refinery	Garyville, LA	RBLC	17.11	Dec-06	Diesel Emergency Generators (2) rated at 1341 hp and 671 hp	Use of diesel with a sulfur content of 15 ppmv or less	0.0067 182	lb/hp-hr hr/yr	3.04	Permitted for 182 operating hours per yr each
ADM Corn Processing - Cedar Rapids	Linn, IA	RBLC	17.11	June-07	Emergency generator	No specific control technology is specifed. Engine is required to meet limits established as BACT (Tier II nonroad). This could require any number of control technologies and operational req. to meet the BACT standard.	2.6	g/bhp-hr	2.6	Equivalent to Tier II standard per 40 CFR 89.
Fairbault Energy Park	Rice, MN	RBLC	17.11	June-07	Emergency generator	None Indicated	0.0055	lbs/hp-hr	2.49	Equal to 2.5 g/bhp hr.
Creole Trail LNG Import Terminal	Cameron, LA	RBLC	17.11	Aug-07	Diesel emergency generator nos. 1 & 2	Good combustion practices and good engine design incorporating fuel injection timing retardation (ITR)	12.24	lbs/hr	–	Limits in g/hp-hr not specified. The engines at the CARBO Ceramics facility will satisfy the federal engine standards of 40 CFR 89 for their respective year of purchase.
Tate & Lyle Ingredients Americas, Inc.	Webster, IA	RBLC	17.11	Sept-08	Fire pump engine	None Indicated	3.5	g/kW-hr	2.61	Equivalent to Tier II standard per 40 CFR 89.
Associated Electric Cooperative, Inc.	Chouteau, OK	RBLC	17.11	Jan-09	Emergency Generator rated at 2200 hp	None indicated	12.66 3.5	lbs/hr g/kW-hr	2.61	Equivalent to Tier II standard per 40 CFR 89.
Shady Hills Power Company Generating Station	Spring Hill, FL	RBLC	17.11	Jan-09	Emergency Generator rated at 2.5 MW	Pollution Prevention	8.5	g/hp-hr	8.5	Equal to 40 CFR 60 Subpart IIII for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)
MGM Mirage	Las Vegas, NV	RBLC	17.11	Nov-09	Two Diesel fired, emergency generators each rated at 2206 hp	Turbocharger and Good Combustion Practices	0.0018 3.95 52	lb/hp-hr lb/hr (ea) hr/yr	0.816	Operating hours restricted to one hour per day and 52 hours per year for each unit

[1] 17.11 = large internal combustion engines (diesel)

As a consequence of our review, pre-combustion control technology, such as Good Combustion Techniques, and post-combustion control technologies, such as Recuperative Thermal Oxidation and Catalytic Oxidation, have been considered as summarized in Table B.4-2 below:

Table B.4-2: Evaluated Control Options for CO Emissions – Emergency Generators Nos. 1 – 4

Option No.	Control Technology
1	Recuperative Thermal Oxidation
2	Catalytic Oxidation
3	Good Combustion Techniques

Option 1 –Recuperative Thermal Oxidation

Carbon monoxide can be oxidized to carbon dioxide and water vapor at high temperatures (generally about 1800°F). Although thermal oxidizers can recover heat energy using recuperative or regenerative methods, and regenerative thermal oxidizers can achieve a much higher heat recovery rate than recuperative thermal oxidizers, cost correlations for regenerative thermal oxidizers are only considered accurate for flue gas flow rates of 10,000-100,000 scfm. As Emergency Generators 1 through 4 each have a gas flow rate of 6,504 scfm, recuperative thermal oxidation, valid for flue gas flow rates of 500-50,000 scfm, has been analyzed for cost effectiveness.

In a recuperative thermal oxidizer, the exhaust air is preheated by means of a heat exchanger before entering the combustion chamber. The hot exhaust from the combustion chamber is then fed through the other side of the heat exchanger to provide the preheating of intake air. Through this means, up to 70%[8] of the heat energy of the exhaust gas can be recovered, allowing for a reduction in fuel consumption. While this degree of heat recovery is less than is possible using the regenerative mechanism, the capital cost of the recuperative design can be substantially lower, which can, in some cases, offset the additional fuel consumption of the recuperative design. This would be particularly likely for units with limited operating time, such as these emergency generators with their 500 hr/yr proposed limit.

The use of Regenerative Thermal Oxidizers to control CO from the diesel-fired emergency generators is deemed technically feasible. The control efficiency of aRecuperative Thermal Oxidizer can be as high as 98%.[8]

Option 2 – Catalytic Oxidation

Catalytic oxidation is a post combustion control technique for reducing emissions of CO and hydrocarbons. A catalytic oxidation system is a passive reactor, which consists of a honeycomb grid of metal panels, typically coated with platinum or rhodium. The catalyst grid is placed in the exhaust where the optimum reaction temperature can be maintained (450°F – 1200°F). The oxidation process takes place spontaneously, without the

[8] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.2.1

requirement for introducing reactants (such as ammonia necessary in NO_x catalysts) into the flue gas stream. The catalyst serves to increase reaction times, thereby enabling conversions to carbon dioxide at lower reaction temperatures than in thermal oxidizers. The catalyst itself is not consumed in the reaction, but merely acts as the surface agent that enables the chemical reactions to take place. The active component of most catalytic oxidation systems is platinum metal, which is applied over a metal or ceramic substrate. When properly operated and maintained, a catalytic oxidizer can achieve a control efficiency as high as 95%.[9] Although the use of a catalytic oxidizer has been found to be technically feasible in theory, there is no indication that it has ever been applied as a measure to control CO in this industry before, and it is generally not applied as widely as thermal oxidation because of its higher sensitivity to pollutant characteristics and process conditions. The use of Catalytic Oxidizer to control CO from the diesel-fired emergency generators is deemed technically feasible.

Option 3- Good Combustion Techniques

Optimization of the design, operation, and maintenance of the emergency generators combustion system is the primary mechanism available for lowering CO. This process is often referred to as combustion controls. The factors involved include continuous mixing of air and fuel in the proper proportions, appropriate residence time, suitable temperatures in the combustion chamber to ensure complete burning, and adequate turbulence in the combustion chamber to ensure good mixing. As a result of the optimum conditions for combustion, CO emissions are minimized.

However, the addition of excess air and maintenance of high combustion temperatures for control of CO can result in an increase in NO_x emissions. Consequently, the typical practice is to design the combustion system (specifically, the air/fuel mixture and emergency generator temperature) such that CO is reduced as much as possible without causing NO_x emissions to significantly increase. This includes maintaining the air/fuel ratio at the specified design point, and maintaining the unit per the manufacturer's recommendations for overall emissions minimization.

Step 2: Eliminate technically infeasible options

All the above control technologies are deemed technically feasible.

[9] Per vendor experience and US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.4

Step 3: Rank remaining technologies by control effectiveness

Table B.4-3: Ranking of Control Technology – Emergency Generators Nos. 1 – 4
Baseline Emissions = 4.38 tpy CO

Control Technology Ranking	Option No.	Control Technology	Control Efficiency	CO Reductions (tpy)
1	1	Recuperative Thermal Oxidation	98%	4.29
2	2	Catalytic Oxidation	95%	4.16
3	3	Good Combustion Techniques	N/A	N/A

Step 4: Evaluate most effective controls and document results

Table B.4-4 below summarizes the energy, environmental, and economic impacts of all remaining control technologies.

Table B.4-4: BACT Control Analysis – Emergency Generators Nos. 1 – 4

						Change in Emissions[2]					
Option No.	Control Technology	Annualized Cost	Cost Effectiveness ($/ton CO Reduced)	Total Energy Consumed (MMBtu/yr)	Water Usage (MGD)	NO_x (tpy)	VOC (tpy)	**CO (tpy)**	GHG (tpy CO_2e)	SO_2 (tpy)	Total PM[1] (tpy)
2	Recuperative Thermal Oxidation	$97,804	$22,812	23,333	0	+1.70	+0.017	**-4.29**	+1,906	+0.018	+0.281
3	Catalytic Oxidation	$82,666	$19,890	21,091	0	+0.154	+0.002	**-4.16**	+172	+0.002	+0.025
4	Good Combustion Techniques	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A

[1] Total PM includes filterables and condensables. All PM assumed to be <2.5 microns.
[2] Calculated emissions detailed in Table B.8-3

As shown in the previous table, the estimated costs exceed the level of cost effectiveness at which the installation of add-on pollution control devices can be deemed reasonable. In addition, the resources and energy that would be required to operate the control technologies are not justified based on the corresponding impacts.

Step 5: Select BACT

In order to effectively control CO emissions from the four diesel-fired emergency generators (Emission Unit ID Nos. EDG1 – EDG4), Good Combustion Techniques with a CO emission limit of 2.6 g/bhp-hr for EDG1 – EDG4 each with a federally enforceable limit of 500 hours of operation per year each, is proposed as BACT. Table B.4-5 summarizes the BACT determination requirements being proposed for the diesel-fired emergency generators.

Table B.4-5: CO BACT Proposed for Diesel Fired Emergency Generators Nos. 1 – 4

Emission Unit ID Nos.	BACT Limit (each emission unit)
EDG1 – EDG4	The use of Good Combustion Techniques with a CO emission limit of 2.6 g/bhp-hr to control emissions from each diesel-fired emergency generator and a limit of 500 operating hours per year each.

Table B.5-1 CO BACT Cost Analysis:
Regenerative Thermal Oxidizers (RTO) on Direct-fired Rotary Calciners Nos. 1 – 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Regenerative Thermal Oxidizer (95% heat recovery - escalated)	$923,075	Base cost per EPA Cost Manual Section 3.2, Equation 2.33; in 1999 dollars Cost correlations range: 10,000 to 100,000 scfm Escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010) / (M&S Index,1999) * (220,400 + 11.57 * (Waste gas flow rate))]
Straight Duct Cost	$96,483	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting
Elbows Cost	$18,230	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688*Duct diameter * 12)) * (No. of elbows)
Instrumentation	$103,779	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC = RTO Cost+ Straight Duct Cost+Elbows Cost
Freight	$51,889	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Purchased Equipment Cost (PEC)	**$1,193,456**	
Direct Installation Costs		
Foundation and Supports	$95,476	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Handling and Erection	$167,084	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Electrical	$47,738	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Piping	$23,869	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Insulation of Duct Work	$11,935	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Painting	$11,935	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Direct Installation Costs (DIC)	**$358,037**	
Total Direct Cost (TDC)	**$1,551,493**	**TDC=PEC+DIC**
Indirect Costs		
Engineering	$119,346	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Construction and Field Expenses	$59,673	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contractor Fees	$119,346	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Start-up	$23,869	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Performance Test	$11,935	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contingencies	$35,804	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Cost of Lost Production	$525,000	Assumes 1-week additional construction time for tie-ins and start-up
Total Indirect Costs (TIC)	**$894,971**	
Total Capital Cost (TCC)	**$2,446,464**	**TCC=TDC+TIC**
Annual Cost		
Operating labor	$16,110	Based on 3 shifts/day, 8,592 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Supervisory labor	$2,417	15% of Operating labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Maintenance labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Maintenance materials	$18,068	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Natural gas	$786,731	As determined in Table B.5-1a
Electricity	$14,661	
Cost of Lost Production for Annual Maintenance & Repair	$525,000	Assumes 1 week annual shutdown for maintenance and repair.
Overhead	$32,797	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.2, Table 2.10
Insurance, administrative	$73,394	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual Section 3.2, Table 2.10
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$230,922	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$1,718,166**	
Total Cost per ton CO controlled	**$16,206**	Based on 108 tpy baseline and 98% control; 106 tons removed

Table B.5-1a CO BACT Energy Cost Analysis: Regenerative Thermal Oxidizers (RTO) on Direct-fired Rotary Calciners Nos. 1 – 4 (each)

Regenerative Thermal Oxidizer Input Parameters	Gas flowrate:	63,000	[acfm]
	Reference temperature:	77	[°F]
	Inlet gas temperature:	405	[°F]
	Gas flowrate:	39,102	[scfm]
	Inlet gas density:[1]	0.046	[lb/acf]
	Primary heat recovery:	0.950	[fraction]
	Waste gas heat content:[2]	0.619	[Btu/lb]
	Waste gas heat capacity:[3]	0.255	[Btu/lb-°F]
	Combustion temperature:	1,800	[°F]
	Heat loss:	0.100	[fraction]
	Exit temperature:	475	[°F]
	Fuel heat of combustion:	23,808	[Btu/lb]
	Fuel density:[4]	0.043	[lb/ft^3]
Regenerative Thermal Oxidizer Design Parameters	Auxiliary Fuel Requirement:[5]	7.46	[lb/min]
	Auxiliary Fuel Requirement:[5]	174.21	[scfm]
	Total Waste Gas Flowrate:	39,276	[scfm]
CO Concentration and Heat of Combustion (Waste Gas) Calculations		Carbon Monoxide	
	Potential Emissions:	108	[tpy]
	Molecular Weight:	28.01	[lb/lb-mol]
	Concentration by Weight:[6]	142	[ppmw]
	Concentration by Volume:[7]	147	[ppmv]
	Waste Gas O_2 Content:	20.9	[%]
	Lower Explosive Limit (LEL):	12.5	[%]
	LEL of CO/Air Mixture:	0.118	[%]
	Heat of Combustion:	4,347	[Btu/lb]
	Heat of Combustion of Waste Gas:[2]	0.619	[Btu/lb]
	Heat of Combustion of Waste Gas:	0.046	[Btu/scf]

Utility Cost Inputs	Average Unit Cost[8,9]	Unit	
Natural Gas[10]	8.76 $/Mscf	89,809 Mscf/yr	$ 786,730.89
Electricity[11]	0.056 $/kWh	263,219 kWh/yr	$ 14,661.29

Footnotes	
1	Based on Ideal Gas Equation at waste gas exhaust temperature, assuming waste gas is principally air.
2	Heat of combustion per pound of inlet waste gas developed from heat of combustion of CO multiplied by the concentration by weight (ppmw) of that CO.
3	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996.
4	Auxiliary fuel is natural gas with heating value assumed at 1,020 Btu/scf.
5	Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).
6	Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (8,760 hrs/yr) / (60 min/hr)) * 1000000 / (Gas flowrate, acfm) * (Inlet gas density, lb/ft^3).
7	Parts per million concentration by weight to volume conversion from AP-42 Appendix A.
8	Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
9	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
10	Natural Gas Units = (Auxiliary fuel requirement) * (60 min/hr) * (8,592 hr/year)
11	Electricity Units = [0.000117 * (Waste gas exhaust flow) * (Total system pressure drop, assumed 4 w.c.) / 0.6] * (8,592 hr/year)] per EPA 452/B-02-001, Section 3.2, Equation 2.42.

Table B.5-2 CO BACT Cost Analysis:
Catalytic Oxidizer on Direct-fired Rotary Calciners Nos. 1 – 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Catalytic Oxidizer (70 % heat recovery - escalated)	$682,635	Base cost per EPA Cost Manual Section 3.2, Equation 2.37; in 1999 dollars Cost correlations range: 2,000 to 50,000 scfm Escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010)/(M&S Index,1999) * (1,443 * (Total gas flowrate)$^{0.5527}$)]
Straight Duct Cost	$96,483	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$18,230	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688 * Duct diameter * 12)) * (No. of elbows)
Instrumentation	$79,735	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC = CatOx Cost+ Straight Duct Cost+Elbows Cost
Freight	$39,867	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Purchased Equipment Cost (PEC)	**$916,950**	
Direct Installation Costs		
Foundation and Supports	$73,356	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Handling and Erection	$128,373	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Electrical	$36,678	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Piping	$18,339	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Insulation of Duct Work	$9,170	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Painting	$9,170	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Direct Installation Costs (DIC)	**$275,085**	
Total Direct Cost (TDC)	**$1,192,036**	**PEC+DIC**
Indirect Costs		
Engineering	$91,695	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Construction and Field Expenses	$45,848	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contractor Fees	$91,695	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Start-up	$18,339	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Performance Test	$9,170	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contingencies	$27,509	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Cost of Lost Production	$525,000	Assumes 1-week additional construction time for tie-ins and start-up
Total Indirect Costs (TIC)	**$809,255**	
Total Capital Cost	**$2,001,290**	**TDC+TIC**
Annual Cost		
Operating labor	$16,110	Based on 3 shifts/day, 8,592 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Supervisory labor	$2,417	15% of Operating labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Maintenance labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Maintenance materials	$18,068	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Natural gas	$566,189	As determined in Table B.5-2a
Electricity	$76,876	
Catalyst replacement	$36,377	Catalyst replacement costs = (volume of catalyst) * (price of catalyst, $/ft3) * (catalyst capital recovery factor) Catalyst volume is determined in Table B.5-2a Recovery factor at 7% interest rate over 4 years
Cost of Lost Production for Annual Maintenance & Repair	$525,000	Assumes 1 week annual shutdown for maintenance and repair.
Overhead	$32,797	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.2, Table 2.10
Insurance, administrative	$60,039	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual Section 3.2, Table 2.10
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$188,908	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$1,540,846**	
Total Cost per ton CO controlled	**$14,992**	Based on 108 tpy baseline and 95% control; 103 tons removed

Table B.5-2a CO BACT Energy Cost Analysis:
Catlytic Oxidizer on Direct-fired Rotary Calciners Nos. 1 – 4 (each)

Catalytic Oxidizer Input Parameters

Gas flowrate:	63,000	[acfm]
Reference temperature:	77	[°F]
Inlet gas temperature:	405	[°F]
Gas flowrate:	39,102	[scfm]
Inlet gas density:[1]	0.046	[lb/acf]
Primary heat recovery:	0.700	[fraction]
Waste gas heat content:[2]	0.619	[Btu/lb]
Waste gas heat capacity:[3]	0.248	[Btu/lb-°F]
Combustion temperature:	750	[°F]
Preheat Exit Temperature:	647	[°F]
Fuel heat of combustion:	23,808	[Btu/lb]
Fuel density:[4]	0.041	[lb/ft^3]

Catalytic Oxidizer Design Parameters

Total Auxiliary Fuel Requirement:[5]	5.12	[lb/min]
Total Auxiliary Fuel Requirement:[5]	125.38	[scfm]
Total Gas Flowrate:	39,227	[scfm]
Total Catalyst Volume:[6]	189.56	[ft^3]

CO Concentration and Heat of Combustion (Waste Gas) Calculations

	Carbon Monoxide	
Potential Emissions:	108.19	[tpy]
Molecular Weight of CO:	28.01	[lb/lb-mol]
Concentration by Weight:[7]	142	[ppmw]
Concentration by Volume:[8]	147	[ppmv]
Waste Gas O_2 Content:	20.9	[%]
Lower Explosive Limit (LEL):	12.5	[%]
LEL of CO/Air Mixture:	0.118	[%]
Heat of Combustion of CO:	4,347	[Btu/lb]
Heat of Combustion of Waste Gas:[2]	0.619	[Btu/lb]
Heat of Combustion of Waste Gas:	0.047	[Btu/scf]

Utility Cost Inputs	Average Unit Cost[9, 10]	Unit		
Natural Gas[11]	8.76 $/Mscf	64,633 Mscf/yr	$	566,188.80
Electricity[12]	0.056 $/kWh	1,380,181 kWh/yr	$	76,876.06

Footnotes

1	Based on ideal gas equation at waste gas exhaust temperature assuming waste gas is principally air.
2	Heat of combustion per pound of inlet waste gas developed from heat of combustion of CO multiplied by the concentration by weight (ppmw) of that CO.
3	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996.
4	Auxiliary fuel is natural gas with heating value assumed at 1,020 Btu/scf.
5	Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).
6	Catalyst volume is determined by the following equation: Φ = (Waste Gas flow rate) / (catalyst volume) Φ = space velocity, h-1 and waste gas flow is specified in cu feet/hour. Φ = 20,000 h-1, per Sec 3.2 Subsection 2.4.3 of the Cost Manual. Therefore, catalyst volume = [(waste gas flow rate) * (60 min/hrs) * (460 + inlet temp) / (460 + ref temp)] / 20,000 h-1
7	Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (8760 hrs/yr) / (60 min/hr)) * 1000000 / (Gas flowrate, acfm) * (Inlet gas density, lb/ft^3).
8	Parts per million concentration by weight to volume conversion from AP-42 Appendix A.
9	Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
10	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
11	Natural Gas Units = (Auxiliary fuel requirement) * (60 min/hr) * (8,760 hr/year) / (1000 scf/Mscf)
12	Electricity Units = [0.000117 * (Waste gas exhaust flow) * (Total system pressure drop, assumed 21" w.c.) / 0.6] * (8,592 hr/year)] per EPA 452/B-02-001, Section 3.2, Equation 2.42.

Table B.5-3: Energy and Environmental Impact Summary for Direct Fired Rotary Calciner Nos. 1 – 4 (each)

	Resource Consumption			Energy Equivalents	
Control Technology	Water (MGD)[1]	Gas (Mscf/yr)[1]	Electricity (kWh/yr)[1]	Total Energy Consumed (MMBtu/yr)[2]	Total Energy Consumed (MMBtu/hr)[3]
Regenerative Thermal Oxidizer	0.00	89,809	263,219	92,504	10.6
Catalytic Oxidation	0.00	64,633	1,380,181	70,637	8.06
Good Combustion Techniques	0.00	0.00	0.00	0.00	0.00

	Collateral Emissions					
Control Technology	NO_x (tpy)[4]	GHG (tpy CO_2e)[5]	CO (tpy)[6]	VOC (tpy)[7]	SO_2 (tpy)[8]	Total PM (tpy)[9,10]
Regenerative Thermal Oxidizer	4.49	5,421	0.075	0.247	0.027	0.341
Catalytic Oxidation	3.23	3,902	0.136	0.178	0.019	0.246
Good Combustion Techniques	0.00	0.00	0.00	0.00	0.00	0.00

Notes	
1	Per cost-effectiveness calculation sheets.
2	Total Energy Consumed, MMBtu/yr = (Gas Consumption, Mscf/yr) / (1,000 Mscf/MMscf) * (1,020 MMBtu/MMscf) + (Electricity Consumption, kWh/year) * (3413 Btu-hr/kWh) / (10^6 Btu/MMBtu)
3	Total Energy Consumed, MMBtu/hr = (Total Energy Consumed, MMBtu/yr) / (8,760 hr/yr)
4	Estimated NO_x emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1, NO_x emissions from small uncontrolled boilers. NO_x tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (100 lb NO_x/MMscf) / (2000 lb/ton)
5	Estimated greenhouse gas (GHG) emissions from natural gas combustion in control device calculated using AP-42 emission factors, 5th Edition, Table 1.4-2. Combined GHG Emission Factor, lb CO_2e/MMscf = (120,000 lb CO_2/MMscf) * (CO_2 GWP =1) + (2.2 lb N_2O/MMscf) * (N_2O GWP=310) + (2.3 lb CH_4/MMscf) * (CH_4 GWP=21) GHG Emissions, tpy CO_2e = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (GHG EF=120,730 lb CO_2e/MMscf) / (2000 lb/ton)
6	Estimated CO emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1. CO, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (84 lb CO/MMscf) / (2000 lb/ton)
7	Estimated VOC emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. VOC, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (5.5 lb VOC/MMscf) / (2000 lb/ton)
8	Estimated SO_2 emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. SO_2, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (0.6 lb SO_2/MMscf) / (2000 lb/ton)
9	Estimated PM emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. PM, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (7.6 lb PM/MMscf) / (2000 lb/ton)
10	Includes filterables and condensables. All PM assumed to be <2.5 microns.

Table B.6-1 CO BACT Cost Analysis:
Regeneratrive Thermal Oxidizer (RTO) on Spray Dryers 1 – 8 (each)

	Cost Element	Budget Amount	Comments
Capital Cost			
Direct Costs			
	Purchased Equipment Costs (PEC)		
	Regenerative Thermal Oxidizer (95% heat recovery - escalated)	$915,116	Base cost per EPA Cost Manual Section 3.2, Equation 2.33; in 1999 dollars Cost correlations range: 10,000 to 100,000 scfm Escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010) / (M&S Index,1999) * (220,400 + 11.57 * (Waste gas flow rate))]
	Straight Duct Cost	$95,709	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
	Elbows Cost	$17,747	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688*Duct diameter * 12)) * (No. of elbows)
	Instrumentation	$102,857	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC=RTO+Straight Duct Cost+Elbows Cost
	Freight	$51,429	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
	Total Purchased Equipment Cost (PEC)	**$1,182,857**	
	Direct Installation Costs		
	Foundation and Supports	$94,629	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Handling and Erection	$165,600	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Electrical	$47,314	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Piping	$23,657	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Insulation of Duct Work	$11,829	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Painting	$11,829	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Direct Installation Costs (DIC)	**$354,857**	
	Total Direct Cost	**$1,537,715**	**TDC=PEC+DIC**
Indirect Costs			
	Engineering	$118,286	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Construction and Field Expenses	$59,143	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Contractor Fees	$118,286	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Start-up	$23,657	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Performance Test	$11,829	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Contingencies	$35,486	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Total Indirect Costs (TIC)	**$366,686**	
Total Capital Cost (TCC)		**$1,904,400**	**TCC=TDC+TIC**
Annual Cost			
	Operating labor	$16,425	Based on 3 shifts/day, 8,760 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
	Supervisory labor	$2,464	15% of Operating labor cost per EPA Cost Manual, Section 3.2, Table 2.10
	Maintenance labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
	Maintenance materials	$18,068	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
	Natural gas	$829,382	As determined in Table B.6-1a
	Electricity	$14,757	
	Overhead	$33,014	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.2, Table 2.10
	Insurance, administrative	$57,132	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual Section 3.2, Table 2.10
	Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
	Capital recovery	$179,762	Total Capital Cost * Capital Recovery Factor
Total Annual Cost		**$1,169,070**	
Total Cost per ton CO Controlled		**$16,407**	Based on 72.7 tpy baseline and 98% control; 71.3 tons removed

Table B.6-1a CO BACT Energy Cost Analysis: Regenerative Thermal Oxidizers (RTO) on Spray Dryers 1 – 8 (each)

Regenerative Thermal Oxidizer Input Parameters

Gas flowrate:	46,000	[acfm]
Reference temperature:	77	[°F]
Inlet gas temperature:	180	[°F]
Gas flowrate:	38,593	[scfm]
Inlet gas density:[1]	0.062	[lb/acf]
Primary heat recovery:	0.950	[fraction]
Waste gas heat content:[2]	0.422	[Btu/lb]
Waste gas heat capacity:[3]	0.255	[Btu/lb-°F]
Combustion temperature:	1,800	[°F]
Heat loss:	0.100	[fraction]
Exit temperature:	261	[°F]
Fuel heat of combustion:	23,808	[Btu/lb]
Fuel density:[4]	0.043	[lb/ft^3]

Regenerative Thermal Oxidizer Design Parameters

Auxiliary Fuel Requirement:[5]	7.72	[lb/min]
Auxiliary Fuel Requirement:[5]	180.13	[scfm]
Total Waste Gas Flowrate:	38,773	[scfm]

CO Concentration and Heat of Combustion (Waste Gas) Calculations

	Carbon Monoxide	
Potential Emissions:	72.71	[tpy]
Molecular Weight:	28.01	[lb/lb-mol]
Concentration by Weight:[6]	97	[ppmw]
Concentration by Volume:[7]	100	[ppmv]
Waste Gas O_2 Content:	20.9	[%]
Lower Explosive Limit (LEL):	12.5	[%]
LEL of CO/Air Mixture:	0.080	[%]
Heat of Combustion:	4,347	[Btu/lb]
Heat of Combustion of Waste Gas:[2]	0.422	[Btu/lb]
Heat of Combustion of Waste Gas:	0.031	[Btu/scf]

Utility Cost Inputs	Average Unit Cost[8,9]	Unit	
Natural Gas[10]	8.76 $/Mscf	94,678 Mscf/yr	$ 829,381.61
Electricity[11]	0.056 $/kWh	264,929 kWh/yr	$ 14,756.57

Footnotes	
1	Based on Ideal Gas Equation at waste gas exhaust temperature, assuming waste gas is principally air.
2	Heat of combustion per pound of inlet waste gas developed from heat of combustion of CO multiplied by the concentration by weight (ppmw) of that CO.
3	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996.
4	Auxiliary fuel is natural gas with heating value assumed at 1,020 Btu/scf.
5	Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).
6	Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (8760 hrs/yr) / (60 min/hr)) * 1000000 / (Gas flowrate, acfm) * (Inlet gas density, lb/ft3)
7	Parts per million concentration by weight to volume conversion from AP-42 Appendix A.
8	Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
9	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
10	Natural Gas Units = (Auxiliary fuel requirement) * (60 min/hr) * (8,760 hr/year)
11	Electricity Units = [0.000117 * (Waste gas exhaust flow) * (Total system pressure drop, assumed 4 w.c.) / 0.6] * (8,760 hr/year)] per EPA 452/B-02-001, Section 3.2, Equation 2.42.

Table B.6-2 CO BACT Cost Analysis:
Catalytic Oxidizer on Spray Dryers 1 – 8 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Catalytic Oxidizer (70 % heat recovery - escalated)	$678,196	Base cost per EPA Cost Manual Section 3.2, Equation 2.37; in 1999 dollars Cost correlations range: 2,000 to 50,000 scfm Escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010)/(M&S Index,1999) * (1,443 * (Total gas flowrate)$^{0.5527}$)]
Straight Duct Cost	$95,709	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$17,747	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688 * Duct diameter * 12)) * (No. of elbows)
Instrumentation	$79,165	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC = CatOx Cost+ Straight Duct Cost+Elbows Cost
Freight	$39,583	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Purchased Equipment Cost	**$910,400**	
Direct Installation Costs		
Foundation and Supports	$72,832	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Handling and Erection	$127,456	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Electrical	$36,416	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Piping	$18,208	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Insulation of Duct Work	$9,104	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Painting	$9,104	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Direct Installation Costs (DIC)	**$273,120**	
Total Direct Cost (TDC)	**$1,183,520**	**TDC=PEC+DIC**
Indirect Costs		
Engineering	$91,040	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Construction and Field Expenses	$45,520	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contractor Fees	$91,040	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Start-up	$18,208	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Performance Test	$9,104	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contingencies	$27,312	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Indirect Costs (TIC)	**$282,224**	
Total Capital Cost (TCC)	**$1,465,744**	**TCC=TDC+TIC**
Annual Cost		
Operating labor	$16,425	Based on 3 shifts/day, 8,760 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Supervisory labor	$2,464	15% of Operating labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Maintenance labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Maintenance materials	$18,068	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Natural gas	$800,840	As determined in Table B.6-2a
Electricity	$77,460	
Catalyst replacement	$26,599	Catalyst replacement costs = (volume of catalyst) * (price of catalyst, $/ft3) * (catalyst capital recovery factor) Catalyst volume is determined in Table B.6-2a Recovery factor at 7% interest rate over 4 years
Overhead	$33,014	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.2, Table 2.10
Insurance, administrative	$43,972	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost Per EPA Cost Manual Section 3.2, Table 2.10
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$138,356	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$1,175,265**	
Total Cost per ton CO controlled	**$17,015**	Based on 72.7 tpy baseline and 95% control; 69.1 tons removed

Table B.6-2a CO BACT Energy Cost Analysis: Catalytic Oxidizer on Spray Dryers 1 – 8 (each)

Catalytic Oxidizer Input Parameters

Parameter	Value	Units
Gas flowrate:	46,000	[acfm]
Reference temperature:	77	[°F]
Inlet gas temperature:	180	[°F]
Gas flowrate:	38,593	[scfm]
Inlet gas density:[1]	0.062	[lb/acf]
Primary heat recovery:	0.700	[fraction]
Waste gas heat content:[2]	0.422	[Btu/lb]
Waste gas heat capacity:[3]	0.248	[Btu/lb-°F]
Combustion temperature:	750	[°F]
Preheat Exit Temperature:	579	[°F]
Fuel heat of combustion:	23,808	[Btu/lb]
Fuel density:[4]	0.041	[lb/ft^3]

Catalytic Oxidizer Design Parameters

Parameter	Value	Units
Total Auxiliary Fuel Requirement:[5]	7.10	[lb/min]
Total Auxiliary Fuel Requirement:[5]	173.93	[scfm]
Total Gas Flowrate:	38,767	[scfm]
Total Catalyst Volume:[6]	138.61	[ft^3]

CO Concentration and Heat of Combustion (Waste Gas) Calculations

Parameter	Carbon Monoxide	Units
Potential Emissions:	72.71	[tpy]
Molecular Weight of CO:	28.01	[lb/lb-mol]
Concentration by Weight:[7]	97	[ppmw]
Concentration by Volume:[8]	100	[ppmv]
Waste Gas O_2 Content:	20.9	[%]
Lower Explosive Limit (LEL):	12.5	[%]
LEL of CO/Air Mixture:	0.080	[%]
Heat of Combustion of CO:	4,347	[Btu/lb]
Heat of Combustion of Waste Gas:[2]	0.422	[Btu/lb]
Heat of Combustion of Waste Gas:	0.032	[Btu/scf]

Utility Cost Inputs	Average Unit Cost[9, 10]	Unit		
Natural Gas[11]	8.76 $/Mscf	91,420 Mscf/yr	$	800,840.16
Electricity[12]	0.056 $/kWh	1,390,657 kWh/yr	$	77,459.61

Footnotes

1 Based on ideal gas equation at waste gas exhaust temperature assuming waste gas is principally air.
2 Heat of combustion per pound of inlet waste gas developed from heat of combustion of CO multiplied by the concentration by weight (ppmw) of that CO.
3 Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996.
4 Auxiliary fuel is natural gas with heating value assumed at 1,020 Btu/scf.
5 Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).
6 Catalyst volume is determined by the following equation: Φ = (Waste Gas flow rate) / (catalyst volume)
Φ = space velocity, h-1 and waste gas flow is specified in cu feet/hour. Φ = 20,000 h-1, per Sec 3.2 Subsection 2.4.3 of the Cost Manual
Therefore, catalyst volume = [(waste gas flow rate) * (60 min/hrs) * (460 + inlet temp) / (460 + ref temp)] / 20,000 h-1
7 Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (8760 hrs/yr) / (60 min/hr)) * 1000000 / (Gas flowrate, acfm) * (Inlet gas density, lb/ft^3).
8 Parts per million concentration by weight to volume conversion from AP-42 Appendix A.
9 Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
10 Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
11 Natural Gas Units = (Auxiliary fuel requirement) * (60 min/hr) * (8,760 hr/year) / (1000 scf/Mscf)
12 Electricity Units = [0.000117 * (Waste gas exhaust flow) * (Total system pressure drop, assumed 21" w.c.) / 0.6] * (8,760 hr/year)] per EPA 452/B-02-001, Section 3.2, Equation 2.42.

Table B.6-3: Energy and Environmental Impact Summary for Spray Dryer Nos. 1 – 8 (each)

	Resource Consumption			Energy Equivalents	
Control Technology	Water (MGD)[1]	Gas (Mscf/yr)[1]	Electricity (kWh/yr)[1]	Total Energy Consumed (MMBtu/yr)[2]	Total Energy Consumed (MMBtu/hr)[3]
Regenerative Thermal Oxidizer	0.00	94,678	264,929	97,476	11.1
Catalytic Oxidation	0.00	91,420	1,390,657	97,995	11.2
Good Combustion Techniques	0.00	0.00	0.00	0.00	0.00

	Collateral Emissions					
Control Technology	NO_x (tpy)[4]	GHG (tpy CO_2e)[5]	CO (tpy)[6]	VOC (tpy)[7]	SO_2 (tpy)[8]	Total PM (tpy)[9,10]
Regenerative Thermal Oxidizer	4.73	5,715	0.080	0.260	0.028	0.360
Catalytic Oxidation	4.57	5,519	0.192	0.251	0.027	0.347
Good Combustion Techniques	0.00	0.00	0.00	0.00	0.00	0.00

Notes	
1	Per cost-effectiveness calculation sheets.
2	Total Energy Consumed, MMBtu/yr = (Gas Consumption, Mscf/yr) / (1,000 Mscf/MMscf) * (1,020 MMBtu/MMscf) + (Electricity Consumption, kWh/year) * (3413 Btu-hr/kWh) / (10^6 Btu/MMBtu)
3	Total Energy Consumed, MMBtu/yr = (Total Energy Consumed, MMBtu/hr) / (8,760 hr/yr)
4	Estimated NO_x emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1, NO_x emissions from small uncontrolled boilers. NO_x tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (100 lb NO_x/MMscf) / (2000 lb/ton)
5	Estimated greenhouse gas (GHG) emissions from natural gas combustion in control device calculated using AP-42 emission factors, 5th Edition, Table 1.4-2. Combined GHG Emission Factor, lb CO_2e/MMscf = (120,000 lb CO_2/MMscf) * (CO_2 GWP =1) + (2.2 lb N_2O/MMscf) * (N_2O GWP=310) + (2.3 lb CH4/MMscf) * (CH_4 GWP=21) GHG Emissions, tpy CO_2e = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (GHG EF=120,730 lb CO_2e/MMscf) / (2000 lb/ton)
6	Estimated CO emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1. CO, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (84 lb CO/MMscf) / (2000 lb/ton)
7	Estimated VOC emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. VOC, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (5.5 lb VOC/MMscf) / (2000 lb/ton)
8	Estimated SO_2 emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. SO_2, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (0.6 lb SO_2/MMscf) / (2000 lb/ton)
9	Estimated PM emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. PM, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (7.6 lb PM/MMscf) / (2000 lb/ton)
10	Includes filterables and condensables. All PM assumed to be <2.5 microns.

Table B.7-1 CO BACT Cost Analysis:
Recuperative Thermal Oxidizer on Boilers 1 – 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Recuperative Thermal Oxidizer (70% heat recovery - escalated)	$185,015	Base cost per EPA Cost Manual Section 3.2, Equation 2.32; in 1999 dollars Cost correlations range: 500 to 50,000 scfm Escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010) / (M&S Index,1999) * (21,342 + (Waste gas flowrate)$^{0.25}$)]
Straight Duct Cost	$13,502.9	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$682.3	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688*Duct diameter * 12)) * (No. of elbows)
Instrumentation	$19,920	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC = RTO Cost+ Straight Duct Cost+Elbows Cost
Freight	$9,960	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Purchased Equipment Cost (PEC)	**$229,080**	
Direct Installation Costs (DIC)		
Foundation and Supports	$18,326	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Handling and Erection	$32,071	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Electrical	$9,163	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Piping	$4,582	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Insulation of Duct Work	$2,291	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Painting	$2,291	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Direct Installation Costs (DIC)	**$68,724**	
Total Direct Cost (TDC)	**$297,804**	**TDC=PEC+DIC**
Indirect Costs		
Engineering	$22,908	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Construction and Field Expenses	$11,454	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contractor Fees	$22,908	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Start-up	$4,582	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Performance Test	$2,291	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contingencies	$6,872	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Indirect Costs (TIC)	**$71,015**	
Total Capital Cost (TCC)	**$368,819**	**TCC=TDC+TIC**
Annual Cost		
Operating labor	$16,425	Based on 3 shifts/day, 8,760 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Supervisory labor	$2,464	15% of Operating labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Maintenance labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Maintenance materials	$18,068	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Natural gas	$70,823	As determined in Table B.7-1a
Electricity	$614.0	
Overhead	$33,014	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.2, Table 2.10
Insurance, administrative	$11,065	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual Section 3.2, Table 2.10
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$34,814	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$205,354**	
Total Cost per ton CO Controlled	**$59,361**	Based on 3.53 tpy baseline and 98% control; 3.46 tons removed

Table B.7-1a CO BACT Energy Cost Analysis: Recuperative Thermal Oxidizers on Boilers 1 – 4 (each)

Regenerative Thermal Oxidizer Input Parameters			
	Gas flowrate:	2,500	[acfm]
	Reference temperature:	77	[^oF]
	Inlet gas temperature:	380	[^oF]
	Gas flowrate:	1,598	[scfm]
	Inlet gas density:[1]	0.047	[lb/acf]
	Primary heat recovery:	0.700	[fraction]
	Waste gas heat content:[2]	0.494	[Btu/lb]
	Waste gas heat capacity:[3]	0.255	[Btu/lb-^oF]
	Combustion temperature:	1,600	[^oF]
	Heat loss:	0.100	[fraction]
	Exit temperature:	746	[^oF]
	Fuel heat of combustion:	23,808	[Btu/lb]
	Fuel density:[4]	0.043	[lb/ft^3]
Regenerative Thermal Oxidizer Design Parameters	Auxiliary Fuel Requirement:[5]	0.66	[lb/min]
	Auxiliary Fuel Requirement:[5]	15.38	[scfm]
	Total Waste Gas Flowrate:	1,613	[scfm]
CO Concentration and Heat of Combustion (Waste Gas) Calculations		Carbon Monoxide	
	Potential Emissions:	3.53	[tpy]
	Molecular Weight:	28.01	[lb/lb-mol]
	Concentration by Weight:[6]	114	[ppmw]
	Concentration by Volume:[7]	118	[ppmv]
	Waste Gas O_2 Content:	20.9	[%]
	Lower Explosive Limit (LEL):	12.5	[%]
	LEL of CO/Air Mixture:	0.094	[%]
	Heat of Combustion:	4,347	[Btu/lb]
	Heat of Combustion of Waste Gas:[2]	0.494	[Btu/lb]
	Heat of Combustion of Waste Gas:	0.037	[Btu/scf]

Utility Cost Inputs	Average Unit Cost[8,9]	Unit		
Natural Gas[10]	8.76 $/Mscf	8,085 Mscf/yr	$	70,823.40
Electricity[11]	0.056 $/kWh	11,023 kWh/yr	$	613.98

Footnotes	
1	Based on Ideal Gas Equation at waste gas exhaust temperature, assuming waste gas is principally air.
2	Heat of combustion per pound of inlet waste gas developed from heat of combustion of CO multiplied by the concentration by weight (ppmw) of that CO.
3	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996.
4	Auxiliary fuel is natural gas with heating value assumed at 1,020 Btu/scf.
5	Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).
6	Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (8760 hrs/yr) / (60 min/hr)) * 1000000 / (Gas flowrate, acfm) * (Inlet gas density, lb/ft^3).
7	Parts per million concentration by weight to volume conversion from AP-42 Appendix A.
8	Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
9	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
10	Natural Gas Units = (Auxiliary fuel requirement) * (60 min/hr) * (8,760 hr/year)
11	Electricity Units = [0.000117 * (Waste gas exhaust flow) * (Total system pressure drop, assumed 4 w.c.) / 0.6] * (8,760 hr/year)] per EPA 452/B-02-001, Section 3.2, Equation 2.42.

Table B.7-2 CO BACT Cost Analysis:
Catalytic Oxidizer on Boilers 1 – 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Catalytic Oxidizer (70 % heat recovery - escalated)	$116,604	Base cost per EPA Cost Manual Section 3.2, Equation 2.37; in 1999 dollars Cost correlations range: 2,000 to 50,000 scfm Escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010)/(M&S Index,1999) * (1,443 * (Total gas flowrate)$^{0.5527}$)]
Straight Duct Cost	$13,503	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$682	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688 * Duct diameter * 12)) * (No. of elbows)
Instrumentation	$13,079	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC = CatOx Cost+ Straight Duct Cost+Elbows Cost
Freight	$6,539	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Purchased Equipment Cost (PEC)	**$150,407**	
Direct Installation Costs		
Foundation and Supports	$12,033	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Handling and Erection	$21,057	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Electrical	$6,016	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Piping	$3,008	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Insulation of Duct Work	$1,504	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Painting	$1,504	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Direct Installation Costs (DIC)	**$45,122**	
Total Direct Cost (TDC)	**$195,530**	**TDC=PEC+DIC**
Indirect Costs		
Engineering	$15,041	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Construction and Field Expenses	$7,520	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contractor Fees	$15,041	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Start-up	$3,008	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Performance Test	$1,504	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contingencies	$4,512	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Indirect Costs (TIC)	**$46,626**	
Total Capital Cost (TCC)	**$242,156**	**TCC=TDC+TIC**
Annual Cost		
Operating labor	$16,425	Based on 3 shifts/day, 8,760 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Supervisory labor	$2,464	15% of Operating labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Maintenance labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Maintenance materials	$18,068	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Natural gas	$24,711	As determined in Table B.7-2a
Electricity	$3,203	
Catalyst replacement	$1,444	Catalyst replacement costs = (volume of catalyst) * (price of catalyst, $/ft3) * (catalyst capital recovery factor) Catalyst volume is determined in Table B.7-2a Recovery factor at 7% interest rate over 4 years
Overhead	$33,014	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.2, Table 2.10
Insurance, administrative	$7,265	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual Section 3.2, Table 2.10
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$22,858	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$147,518**	
Total Cost per ton CO controlled	**$43,989**	Based on 3.53 tpy baseline and 95% control; 3.35 tons removed

Table B.7-2a CO BACT Energy Cost Analysis: Catalytic Oxidizer on Boilers 1 – 4 (each)

Catalytic Oxidizer Input Parameters

Gas flowrate:	2,500	[acfm]
Reference temperature:	77	[^oF]
Inlet gas temperature:	380	[^oF]
Gas flowrate:	1,598	[scfm]
Inlet gas density:[1]	0.047	[lb/acf]
Primary heat recovery:	0.700	[fraction]
Waste gas heat content:[2]	0.494	[Btu/lb]
Waste gas heat capacity:[3]	0.248	[Btu/lb-^oF]
Combustion temperature:	750	[^oF]
Preheat Exit Temperature:	639	[^oF]
Fuel heat of combustion:	23,808	[Btu/lb]
Fuel density:[4]	0.041	[lb/ft^3]

Catalytic Oxidizer Design Parameters

Total Auxiliary Fuel Requirement:[5]	0.22	[lb/min]
Total Auxiliary Fuel Requirement:[5]	5.37	[scfm]
Total Gas Flowrate:	1,603	[scfm]
Total Catalyst Volume:[6]	7.52	[ft^3]

CO Concentration and Heat of Combustion (Waste Gas) Calculations

	Carbon Monoxide	
Potential Emissions:	3.53	[tpy]
Molecular Weight of CO:	28.01	[lb/lb-mol]
Concentration by Weight:[7]	114	[ppmw]
Concentration by Volume:[8]	118	[ppmv]
Waste Gas O2 Content:	20.9	[%]
Lower Explosive Limit (LEL):	12.5	[%]
LEL of CO/Air Mixture:	0.094	[%]
Heat of Combustion of CO:	4,347	[Btu/lb]
Heat of Combustion of Waste Gas:[2]	0.494	[Btu/lb]
Heat of Combustion of Waste Gas:	0.037	[Btu/scf]

Utility Cost Inputs	Average Unit Cost[9, 10]	Unit		
Natural Gas[11]	8.76 $/Mscf	2,821 Mscf/yr	$	24,710.57
Electricity[12]	0.056 $/kWh	57,511 kWh/yr	$	3,203.38

Footnotes

1 Based on ideal gas equation at waste gas exhaust temperature assuming waste gas is principally air.
2 Heat of combustion per pound of inlet waste gas developed from heat of combustion of CO multiplied by the concentration by weight (ppmw) of that CO.
3 Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996.
4 Auxiliary fuel is natural gas with heating value assumed at 1,020 Btu/scf.
5 Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).
6 Catalyst volume is determined by the following equation: Φ = (Waste Gas flow rate) / (catalyst volume)
Φ = space velocity, h-1 and waste gas flow is specified in cu feet/hour. Φ = 20,000 h-1, per Sec 3.2 Subsection 2.4.3 of the Cost Manual
Therefore, catalyst volume = [(waste gas flow rate) * (60 min/hrs) * (460 + inlet temp) / (460 + ref temp)] / 20,000 h-1
7 Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (8760 hrs/yr) / (60 min/hr)) * 1000000 / (Gas flowrate, acfm) * (Inlet gas density, lb/ft^3).
8 Parts per million concentration by weight to volume conversion from AP-42 Appendix A.
9 Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
10 Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
11 Natural Gas Units = (Auxiliary fuel requirement) * (60 min/hr) * (8,760 hr/year) / (1000 scf/Mscf)
12 Electricity Units = [0.000117 * (Waste gas exhaust flow) * (Total system pressure drop, assumed 21" w.c.) / 0.6] * (8,760 hr/year)] per EPA 452/B-02-001, Section 3.2, Equation 2.42.

Table B.7-3: Energy and Environmental Impact Summary for Boiler Nos. 1 – 4 (each)

	Resource Consumption			Energy Equivalents	
Control Technology	**Water (MMgal/yr)[1]**	**Gas (Mscf/yr)[1]**	**Electricity (kWh/yr)[1]**	**Total Energy Consumed (MMBtu/yr)[2]**	**Total Energy Consumed (MMBtu/hr)[3]**
Recuperative Thermal Oxidizer	0.0	8,085	11,023	8,284	0.946
Catalytic Oxidation	0.0	2,821	57,511	3,074	0.351
Good Combustion Techniques	0.0	0.0	0.0	0.0	0.0

	Collateral Emissions					
Control Technology	**NO_x (tpy)[4]**	**GHG (tpy CO_2e)[5]**	**CO (tpy)[6]**	**VOC (tpy)[7]**	**SO_2 (tpy)[8]**	**Total PM (tpy)[9,10]**
Recuperative Thermal Oxidizer	0.404	488	0.007	0.022	0.002	0.031
Catalytic Oxidation	0.141	170	0.006	0.008	0.001	0.011
Good Combustion Techniques	0.000	0.000	0.000	0.000	0.000	0.000

Notes	
1	Per cost-effectiveness calculation sheets.
2	Total Energy Consumed, MMBtu/yr = (Gas Consumption, Mscf/yr) / (1,000 Mscf/MMscf) * (1,020 MMBtu/MMscf) + (Electricity Consumption, kWh/year) * (3413 Btu-hr/kWh) / (10^6 Btu/MMBtu)
3	Total Energy Consumed, MMBtu/hr = (Total Energy Consumed, MMBtu/yr) / (8,760 hr/yr)
4	Estimated NO_x emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1, NO_x emissions from small uncontrolled boilers. NO_x tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (100 lb NO_x/MMscf) / (2000 lb/ton)
5	Estimated greenhouse gas (GHG) emissions from natural gas combustion in control device calculated using AP-42 emission factors, 5th Edition, Table 1.4-2. Combined GHG Emission Factor, lb CO_2e/MMscf = (120,000 lb CO_2/MMscf) * (CO_2 GWP =1) + (2.2 lb N_2O/MMscf) * (N_2O GWP=310) + (2.3 lb CH_4/MMscf) * (CH_4 GWP=21) GHG Emissions, tpy CO_2e = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (GHG EF=120,730 lb CO_2e/MMscf) / (2000 lb/ton)
6	Estimated CO emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1. CO, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (84 lb CO/MMscf) / (2000 lb/ton)
7	Estimated VOC emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. VOC, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (5.5 lb VOC/MMscf) / (2000 lb/ton)
8	Estimated SO_2 emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. SO_2, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (0.6 lb SO_2/MMscf) / (2000 lb/ton)
9	Estimated PM emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. PM, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (7.6 lb PM/MMscf) / (2000 lb/ton)
10	Total PM includes filterables and condensables. All PM assumed to be <2.5 microns.

Table B.8-1 CO BACT Cost Analysis: Recuperative Thermal Oxidizer on Emergency Generators 1 – 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Recuperative Thermal Oxidizer (70% heat recovery - escalated)	$266,668	Base cost per EPA Cost Manual Section 3.2, Equation 2.32; in 1999 dollars Cost correlations range: 500 to 50,000 scfm Escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010) / (M&S Index,1999) * (21,342 + (Waste gas flowrate)$^{0.25}$)]
Straight Duct Cost	$32,016	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$1,592	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688*Duct diameter * 12)) * (No. of elbows)
Instrumentation	$30,028	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC = RTO Cost+ Straight Duct Cost+Elbows Cost
Freight	$15,014	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Purchased Equipment Cost (PEC)	**$345,317**	
Direct Installation Costs		
Foundation and Supports	$27,625	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Handling and Erection	$48,344	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Electrical	$13,813	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Piping	$6,906	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Insulation of Duct Work	$3,453	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Painting	$3,453	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Direct Installation Costs (DIC)	**$103,595**	
Total Direct Cost (TDC)	**$448,912**	**TDC=PEC+DIC**
Indirect Costs		
Engineering	$34,532	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Construction and Field Expenses	$17,266	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contractor Fees	$34,532	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Start-up	$6,906	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Performance Test	$3,453	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contingencies	$10,360	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Indirect Costs (TIC)	**$107,048**	
Total Capital Cost (TCC)	**$555,960**	**TCC=TDC+TIC**
Annual Cost		
Operating labor	$938	Based on 3 shifts/day, 500 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Supervisory labor	$141	15% of Operating labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Maintenance labor	$1,031	Based on 3 shifts/day, 500 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Maintenance materials	$1,031	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Auxiliary Fuel	$23,622	As determined in Table B.8-1a
Overhead	$1,884	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.2, Table 2.10
Insurance, administrative	$16,679	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual Section 3.2, Table 2.10
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$52,479	Calculated using EPA Cost Manual Section 1, Eqn. 2.8
Total Annual Cost	**$97,804**	
Total Cost per ton CO Controlled	**$22,812**	Based on 4.38 tpy baseline and 98% control; 4.29 tons removed

Table B.8-1a CO BACT Energy Cost Analysis:
Recuperative Thermal Oxidizers on Emergency Generators 1 – 4 (each)

Regenerative Thermal Oxidizer Input Parameters	Gas flowrate:	16,103	[acfm]
	Reference temperature:	77	[°F]
	Inlet gas temperature:	869	[°F]
	Gas flowrate:	6,504	[scfm]
	Inlet gas density:[1]	0.030	[lb/acf]
	Primary heat recovery:	0.700	[fraction]
	Waste gas heat content:[2]	2.637	[Btu/lb]
	Waste gas heat capacity:[3]	0.255	[Btu/lb-°F]
	Combustion temperature:	1,600	[°F]
	Heat loss:	0.100	[fraction]
	Exit temperature:	1088	[°F]
	Fuel heat of combustion:[4]	137,000	[Btu/gal]

Recuperative Thermal Oxidizer Design Parameters	Auxiliary Fuel Requirement:[5]	0.32	[gal/min]
	Auxiliary Fuel Requirement:[4,5]	0.044	[MMBtu/min]
	Exhaust Flow Rate from Auxiliary Burner Combustion:[6]	458	[scfm]
	Total Waste Gas Flowrate:	6,962	[scfm]

CO Concentration and Heat of Combustion (Waste Gas) Calculations		Carbon Monoxide	
	Potential Emissions:	4.38	[tpy]
	Molecular Weight:	28.01	[lb/lb-mol]
	Concentration by Weight:[7]	607	[ppmw]
	Concentration by Volume:[8]	627	[ppmv]
	Waste Gas O_2 Content:	20.9	[%]
	Lower Explosive Limit (LEL):	12.5	[%]
	LEL of CO/Air Mixture:	0.502	[%]
	Heat of Combustion:	4,347	[Btu/lb]
	Heat of Combustion of Waste Gas:[9]	2.637	[Btu/lb]
	Heat of Combustion of Waste Gas:	0.195	[Btu/scf]

Auxiliary Fuel	Average Unit Cost[9]	Unit[10]	Hours/Year[11]	
Diesel Fuel (ULSD)	2.43 $/gal	19.4 gal/hr	500	$ 23,621.96

Footnotes	
1	Based on Ideal Gas Equation at waste gas exhaust temperature, assuming waste gas is principally air.
2	Heat of combustion per pound of inlet waste gas developed from heat of combustion of CO multiplied by the concentration by weight (ppmw) of that CO.
3	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996.
4	Auxiliary fuel is diesel with heating value assumed at 137,000 Btu/gal
5	Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).
6	Flow Rate (scfm)= (Aux. Fuel Requirement, MMBtu/min) * (10,320 wscf/MMBtu) Combustion F-Factor per EPA Test Method 19, Table 19-2
7	Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (500 hrs/yr) / (60 min/hr)) * 1000000 / (Gas flowrate, acfm) * (Inlet gas density, lb/ft ^{3}).
8	Parts per million concentration by weight to volume conversion from AP-42 Appendix A.
9	Diesel fuel unit cost is the mean of the 3 years (2007-2009) of annual average ULSD price data available for industrial sector consumers in the Gulf Coast Region per US Dept. of Energy, Energy Information Administration; see http://www.eia.gov/dnav/pet/pet_pri_dist_dcu_R30_a.htm
10	Diesel Fuel Units = (Auxiliary fuel requirement, gal/min) * (60 min/hr)
11	Oxidizer requires auxiliary fuel during all system operation; operation will be subject to proposed 500 hr/year limit

Table B.8-2 CO BACT Cost Analysis:
Catalytic Oxidizer on Emergency Generators 1 – 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Catalytic Oxidizer (70 % heat recovery - escalated)	$253,741	Base cost per EPA Cost Manual Section 3.2, Equation 2.37; in 1999 dollars Cost correlations range: 2,000 to 50,000 scfm Escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010)/(M&S Index,1999) * (1,443 * (Total gas flowrate)$^{0.5527}$)]
Straight Duct Cost	$32,016	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$1,592	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688 * Duct diameter * 12)) * (No. of elbows)
Instrumentation	$28,735	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC = CatOx Cost+ Straight Duct Cost+Elbows Cost
Freight	$14,367	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Purchased Equipment Cost (PEC)	$330,450	
Direct Installation Costs		
Foundation and Supports	$26,436	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Handling and Erection	$46,263	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Electrical	$13,218	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Piping	$6,609	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Insulation of Duct Work	$3,305	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Painting	$3,305	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Direct Installation Costs (DIC)	**$99,135**	
Total Direct Cost (TDC)	**$429,585**	**TDC=PEC+DIC**
Indirect Costs		
Engineering	$33,045	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Construction and Field Expenses	$16,523	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contractor Fees	$33,045	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Start-up	$6,609	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Performance Test	$3,305	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contingencies	$9,914	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Indirect Cost (TIC)	**$102,440**	
Total Capital Cost (TCC)	**$532,025**	**TCC=TDC+TIC**
Annual Cost		
Operating labor	$938	Based on 3 shifts/day, 500 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Supervisory labor	$141	15% of Operating labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Maintenance labor	$1,031	Based on 3 shifts/day, 500 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Maintenance materials	$1,031	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Natural gas	$2,135	As determined in Table B.8-2a
Catalyst replacement	$9,326	Catalyst replacement costs = (volume of catalyst) * (price of catalyst, $/ft^3) * (catalyst capital recovery factor) Catalyst volume is determined in Table B.8-2a Recovery factor at 7% interest rate over 4 years = 0.2952 Catalyst Price = $650/ft^3
Overhead	$1,884	Overhead = 0.6*(cost of labor and materials) Per EPA Cost Manual, Section 3.2, Table 2.10
Insurance, administrative	$15,961	Capital Recovery factor from EPA Control Cost Manual, Section 1, Chapter 2, Appendix A, Table A-2, at 7% interest rate over 20 years
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$50,219	Calculated using EPA Cost Manual Section 1, Eqn. 2.8
Total Annual Cost	**$82,666**	
Total Cost per ton CO Controlled	**$19,890**	Based on 4.38 tpy baseline and 95% control; 4.16 tons removed

Table B.8-2a CO BACT Energy Cost Analysis: Catalytic Oxidizer on Emergency Generators 1 – 4 (each)

Catalytic Oxidizer Input Parameters	Gas flowrate:	16,103	[acfm]
	Reference temperature:	77	[^oF]
	Inlet gas temperature:	869	[^oF]
	Gas flowrate:	6,504	[scfm]
	Inlet gas density:[1]	0.030	[lb/acf]
	Primary heat recovery:	0.700	[fraction]
	Waste gas heat content:[2]	2.637	[Btu/lb]
	Waste gas heat capacity:[3]	0.248	[Btu/lb-^oF]
	Combustion temperature:	750	[^oF]
	Preheat Exit Temperature:	786	[^oF]
	Fuel heat of combustion:	137,000	[Btu/gal]
Catalytic Oxidizer Design Parameters	Auxiliary Fuel Requirement:[5]	0.03	[gal/min]
	Auxiliary Fuel Requirement:[5]	0.004	[MMBtu/min]
	Exhaust Flow Rate from Auxiliary Burner Combustion:[6]	41	[scfm]
	Total Gas Flowrate:	6,546	[scfm]
	Total Catalyst Volume:[7]	48.60	[ft^3]
CO Concentration and Heat of Combustion (Waste Gas) Calculations		Carbon Monoxide	
	Potential Emissions:	4.38	[tpy]
	Molecular Weight of CO:	28.01	[lb/lb-mol]
	Concentration by Weight:[8]	607	[ppmw]
	Concentration by Volume:[9]	627	[ppmv]
	Waste Gas O2 Content:	20.9	[%]
	Lower Explosive Limit (LEL):	12.5	[%]
	LEL of CO/Air Mixture:	0.502	[%]
	Heat of Combustion of CO:	4,347	[Btu/lb]
	Heat of Combustion of Waste Gas:[2]	2.637	[Btu/lb]
	Heat of Combustion of Waste Gas:	0.198	[Btu/scf]

Utility Cost Inputs	Average Unit Cost[10]	Unit[11]	Hours/yr[12]		
Diesel Fuel (ULSD)	2.43 $/gal	1.76 gal/hr	500	$	2,135.26

Footnotes

1	Based on ideal gas equation at waste gas exhaust temperature assuming waste gas is principally air.
2	Heat of combustion per pound of inlet waste gas developed from heat of combustion of CO multiplied by the concentration by weight (ppmw) of that CO.
3	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996.
4	Auxiliary fuel is diesel with heating value assumed at 137,000 Btu/gal
5	Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).
6	Flow Rate (scfm)= (Aux. Fuel Requirement, MMBtu/min) * (10,320 wscf/MMBtu) Combustion F-Factor per EPA Test Method 19, Table 19-2
7	Catalyst volume is determined by the following equation: Φ = (Waste Gas flow rate) / (catalyst volume) Φ = space velocity, h-1 and waste gas flow is specified in cu feet/hour. Φ = 20,000 h-1, per Sec 3.2 Subsection 2.4.3 of the Cost Manual Therefore, catalyst volume = [(waste gas flow rate) * (60 min/hrs) * (460 + inlet temp) / (460 + ref temp)] / 20,000 h-1
8	Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (8760 hrs/yr) / (60 min/hr)) * 1000000 / (Gas flowrate, acfm) * (Inlet gas density, lb/ft^3).
9	Parts per million concentration by weight to volume conversion from AP-42 Appendix A.
10	Diesel fuel unit cost is the mean of the 3 years (2007-2009) of annual average ULSD price data available for industrial sector consumers in the Gulf Coast Region per US Dept. of Energy, Energy Information Administration; see http://www.eia.gov/dnav/pet/pet_pri_dist_dcu_R30_a.htm
11	Diesel Fuel Units = (Auxiliary fuel requirement, gal/min) * (60 min/hr)
12	Oxidizer requires auxiliary fuel during all system operation for flame stabilization; operation will be subject to proposed 500 hr/year limit

Table B.8-3: Energy and Environmental Impact Summary for Emergency Generator Nos. 1 – 4 (each)

	Resource Consumption			Energy Equivalents	
Control Technology	Water (MGD)[1]	Diesel Fuel (gal/yr)[1]	Electricity (kWh/yr)[1]	Total Energy Consumed (MMBtu/yr)[2]	Total Energy Consumed (MMBtu/hr)[3]
Recuperative Thermal Oxidizer	0.00	170,311	0.00	23,333	46.665
Catalytic Oxidation	0.00	15,395	0.00	21,091	42.182
Good Combustion Techniques	0.00	0.00	0.00	0.00	0.00

	Collateral Emissions					
Control Technology	NO_x (tpy)[4]	GHG (tpy CO_2e)[5]	CO (tpy)[6]	VOC (tpy)[7]	SO_2 (tpy)[8]	Total PM (tpy)[9,10]
Recuperative Thermal Oxidizer	1.70	1,906	0.009	0.017	0.018	0.281
Catalytic Oxidation	0.154	172	0.002	0.002	0.002	0.025
Good Combustion Techniques	0.000	0.000	0.000	0.000	0.000	0.000

Notes	
1	Per cost-effectiveness calculation sheets.
2	Total Energy Consumed, MMBtu/yr = (Diesel Fuel Consumption, gal/year) * (137,000 Btu/gal) / (10^6 Btu/MMBtu) + (Electricity Consumption, kWh/year) * (3413 Btu-hr/kWh) / (10^6 Btu/MMBtu)
3	Total Energy Consumed, MMBtu/hr = (Total Energy Consumed, MMBtu/yr) / (500 hr/yr)
4	Estimated NO_x emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-1, NO_x emissions from small uncontrolled boilers. NO_x tpy = (Gas Consumption, gal) * (1 Kgal/1000 gal) * (20 lb NO_x/Kgal) / (2000 lb/ton)
5	Estimated greenhouse gas (GHG) emissions from diesel combustion in control device calculated using AP-42 emission factors, 5th Edition, Tables 1.3-8 and 1.3-12. Combined GHG Emission Factor, lb CO_2e/kgal = (22,300 lb CO_2/kgal) * (CO_2 GWP =1) + (0.260 lb N_2O/kgal) * (N_2O GWP=310) + (2.3 lb CH_4/MMscf) * (CH_4 GWP=21) GHG Emissions, tpy CO_2e = (Gas Consumption, gal) * (1 kgal/1000 gal) * (GHG EF=22,382 lb CO_2e/kgal) / (2000 lb/ton)
6	Estimated CO emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-1. CO, tpy = (Gas Consumption, gal) * (1 kgal/1000 gal) * (5 lb CO/kgal) / (2000 lb/ton)
7	Estimated VOC emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-3. VOC, tpy = (Gas Consumption, gal) * (1 kgal/1000 gal) * (0.200 lb VOC/kgal) / (2000 lb/ton)
8	Estimated SO_2 emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-1. SO_2, tpy = (Gas Consumption, gal) * (1 kgal/1000 gal) * (142S lb SO_2/kgal) / (2000 lb/ton); S=sulfur content = 0.0015%
9	Estimated PM emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-1 and 1.3-2. PM, tpy = (Gas Consumption, gal) * (1 kgal/1000 gal) * (3.3 lb PM/kgal) / (2000 lb/ton) Total PM E.F. = 3.3 (Filterable E.F=2.0 lb/kgal and condensable E.F.=1.3 lb/kgal)
10	Total PM includes filterables and condensables. All PM assumed to be <2.5 microns

ATTACHMENT C

Detailed SO_2 BACT Analysis

VOLUME II, ATTACHMENT C
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C. Top-Down BACT Analysis: Sulfur Dioxide (SO_2)

C.1 SO_2 Review: Direct Fired Rotary Calciner Nos. 1 – 4

SO_2 emissions from Direct-fired Rotary Calciner Nos. 1 – 4 are primarily generated from the oxidation of naturally occurring sulfur found in the processed clay, as well as combustion of natural gas. End-of-pipe control technologies, such as wet and dry scrubbing, as well as good operating practices such as exclusive combustion of natural gas and propane, are evaluated for the control of SO_2 emissions from Direct-fired Rotary Calciners 1 – 4.

This analysis is based on baseline SO_2 emissions of 3,000 tpy. This emission rate has been selected based on engineering testing and sampling as specified in Attachment B, Table 2 (Note 5).

Step 1: Identify all control technologies

In reviewing the BACT alternatives to control emissions of SO_2 from the direct-fired rotary calciner, applicable BACT determinations and permits for non-metallic mineral processing plants have been reviewed, as summarized in Table C.1-1 below:

Table C.1-1: Summary of SO_2 Control Technology Determinations for Kilns and Calciners

Facility Name	Location	Agency	Database	Permit Date	Process Type[1]	Process Description	Controls / Type	Emission Limits/ Description
Eagle-Picher Filtration and Minerals, Inc.	Malheur, OR	OR DEQ	RBLC	May-03	90.024	Natural Gas-fired Dryer/ Calciner	Selective Mining of raw material with low sulfur content	5.6 lb/ton Product, 60% efficiency
Martin Marietta Magnesia Specialties, Inc	Woodville, OH	OH EPA	RBLC	Nov-08	90.019	Coal, Coke, Natural Gas-fired Rotary Lime Kiln	Max fuel usage of 200,000 scf/hr; Fuel quality shall have a sulfur content not exceeding a percent by weight that would calculate to 63.79 lbs S/hr	279.23 tpy 1.7 lb/ton product
CARBO – Toomsboro	Toomsboro, GA	GA EPD	Title V Permit	Dec-09	90.017	Natural gas-fired Rotary Calciners	Good combustion techniques / PSD	34.25 lb/hr
CARBO – McIntyre	McIntyre, GA	GA EPD	Title V Permit	Dec-09	90.017	Natural gas-fired Rotary Calciners	Good combustion techniques / PSD	34.25 lb/hr

[1] 90.017 = Calciners & Dryers and Mineral Processing Facilities, 90.024 = Nonmetallic mineral processing (excludes 90.017), 90.019 = Lime/Limestone Handling/Kilns/Storage/Manufacturing

As a consequence of our review, and the evaluation of other available control technology options, the use of dry scrubbing, wet scrubbing, fuel/raw material pretreatment, and natural gas/propane as fuel are potential control technologies being considered as noted in Table C.1-2 below.

Table C.1-2: Evaluated Control Options for SO_2 Emissions – Direct-fired Rotary Calciner Nos. 1 – 4

Option No.	Control Technology
1	Fuel/Raw Material Pretreatment
2	Wet Scrubber
3	Dry Scrubber (Spray Dryer)
4	Dry Scrubber (Injection System)
5	Use of Natural Gas or Propane as a fuel

Option 1 – Fuel/Raw Material Pretreatment

Fuel pretreatment technologies have been applied to gaseous, liquid, and solid fuels to reduce their sulfur content prior to combustion of the fuel in a processing unit, such as in fuel desulfurization. Raw materials can also be pretreated to reduce their sulfur content prior to the processing step, further reducing SO_2 emissions.

Option 2 – Wet Scrubber

Wet scrubbing systems remove SO_2 from exhaust streams by utilizing an alkaline reagent to form aqueous sulfite and sulfate salts. The reaction of SO_2 with the alkaline chemical can be performed using sodium, calcium, or dual-alkali reagents using packed bed scrubbers or spray towers. Wet scrubber systems generate wastewater and wet sludge streams which require treatment and disposal. The control efficiency of wet scrubber systems is considered to be 95%[1].

Option 3- Semi-Dry Scrubber (Spray Dryer Type)

In a spray dryer type dry scrubbing system, a slurry of alkaline reagent, typically lime or sodium based, is atomized into the hot flue gas to absorb the sulfur dioxide. The resulting dry material is collected in a downstream particulate matter control device, typically an electrostatic precipitator or fabric filter. Lime is usually preferred as sorbent because it is more reactive than limestone and less expensive than sodium based reagents. These systems are designed for SO_2 removal efficiencies of about 80%.[2]

Option 4- Dry Scrubber (Injection System)

Dry injection based dry scrubbing systems involve the direct injection of a dry lime or sodium based reagent into the flue gas in the direct-fired rotary calciner. Sulfur oxides react directly with the reagent, and the dry waste is removed by particulate control equipment. Dry injection systems are usually applied when lower removal efficiencies are required or for smaller plants, and have control efficiencies of about 50%[3] for SO_2.

[1] Control Efficiencies as published by the Institute of Clean Air Companies (ICAC). "*Acid Gas/SO_2 Control Technologies*". http://www.icac.com/i4a/pages/index.cfm?pageid=3401
[2] Per EPA Document EPA-453/F-03-034 "*Air Pollution Control Technology Fact Sheet – Flue Gas Desulfurization*", CICA. http://www.epa.gov/ttn/catc/dir1/ffdg.pdf
[3] Control Efficiencies as published by the Institute of Clean Air Companies (ICAC). "*Acid Gas/SO_2 Control Technologies*". http://www.icac.com/i4a/pages/index.cfm?pageid=3401

Option 5 – Use of Natural Gas or Propane as a fuel

Natural Gas is a clean fuel and is readily available in the State of Georgia. The sulfur content of natural gas or propane is lower than other fuels, and its usage keeps SO_2 emissions to a minimum. Using natural gas greatly reduces SO_2 emissions relative to burning coal. This option serves as the baseline for SO_2 BACT analysis as the source definition is based on the exclusive use of these clean-burning fuels.

Step 2: Eliminate technically infeasible options

Option 1 – Fuel/Raw Material Pretreatment

Fuel pretreatment technologies have been applied to gaseous, liquid, and solid fuels to reduce their sulfur content prior to delivery to the end fuel users. The fuel used in the raw material calciner is natural gas and has minimal sulfur content. Additionally, there are no known established technologies for removing sulfur contained in kaolin clay prior to calcination, and CARBO is yet to demonstrate that material pre-treatment is effective in redcucing sulfur compounds. Therefore, fuel and raw material pre-treatment is considered technically infeasible and is not considered further in this BACT analysis.

Step 3: Rank remaining technologies by control effectiveness

Table C.1-3: **Ranking of Control Technology – Direct-fired Rotary Calciner Nos. 1 – 4**
Baseline Emissions = 3,000 tpy SO_2

Control Technology Ranking	Option No.	Control Technology	Control Efficiency	SO_2 Reductions (tpy)
1	2	Wet Scrubber	95%	2,850
2	3	Semi-Dry Scrubber (Spray Dryer Type)	80%	2,400
3	4	Dry Scrubber (Injection System)	50%	1,500
4	5	Use of Natural Gas or Propane as a fuel	N/A	N/A

Step 4: Evaluate most effective controls and document results

Option 2 – Wet Scrubber

The facility is proposing to install and operate a wet scrubber as to control SO_2 from each of the direct-fired rotary calciner (Nos 1 through 4). As the wet scrubber has not been shown to be infeasible and is the top-ranked control technology, we believe the use of a wet scrubbing system to control SO_2 should be considered BACT for Direct-fired Rotary Calciner Nos. 1 – 4. As the top SO_2 control option has been selelcted, no cost effectiveness analysis and environmental impacts of the control technology options has been performed.

Step 5: Select BACT

The use of a wet scrubber with an emissions limitation of 34.25 lbs/hr of SO_2 is proposed as BACT for Direct-fired Rotary Calciner Nos. 1 – 4 (Emissions Unit ID Nos. KLN1 – KLN4), as summarized in Table C.1-4 below. The emission limit is derived from baseline emissions of 3,000 tpy or 685 lb/hr of SO_2 at 95% control efficiency.

Table C.1-4: SO_2 BACT Proposed for Direct-fired Rotary Calciner Nos. 1 – 4

Emission Unit ID Nos.	BACT	BACT Emissions Limit (each emission unit)
KLN1 – KLN4	The use of a Wet Scrubber as an add-on control device	Wet scrubber and 34.25 lbs/hr SO_2

C.2 SO_2 Review: Spray Dryers Nos. 1 – 8

SO_2 emissions from Spray Dryer Nos. 1 – 8 are primarily generated from the oxidation of the naturally occurring sulfur found in the processed kaolin clay, as well as combustion of natural gas. End-of-pipe control technologies, such as wet and dry scrubbing, as well as good operation practices, such as exclusive combustion of natural gas and propane, were evaluated for the control of SO_2 emissions from Spray Dryer Nos. 1 – 8.

This analysis is based on baseline SO_2 emissions of 0.50 lb/hr or 2.19 tpy. This emission rate has been selected based on engineering testing and dispersion modeling analyses.

Step 1: Identify all control technologies

In reviewing the BACT alternatives to control emissions of SO_2 from the spray dryers, all applicable BACT determinations and permits for non-metallic mineral processing plants have been reviewed, as summarized in Table C.2-1 below:

Table C.2-1: Summary of SO_2 Control Technology Determinations for Spray Dryers

Facility Name	Location	Agency	Database	Permit Date	Process Type[1]	Process Description	Controls / Type	Emission Limits/ Description
First Energy	Lucas, OH	OH EPA	RBLC	Jul-03	90.019	Limestone Dryer	Number 2 fuel oil not to exceed 0.39% sulfur, and all fuel oil tested	4.38 lb/hr
Eagle-Picher Filtration and Minerals, Inc.	Malheur, OR	OR DEQ	RBLC	May-03	90.024	Dryer/ Calciner	Selective Mining of coal with low sulfur content	5.6 lb/ton Product

[1]90.024 = Nonmetallic mineral processing (excludes 90.017), 90.019 = Lime/Limestone Handling/Kilns/Storage/ Manufacturing

As a consequence of our review, and the evaluation of other available control technology options, the use of dry scrubbing, wet scrubbing, fuel/raw material pretreatment and natural gas or propane as fuel are the control technologies being evaluated as BACT as noted in Table C.2-2 below.

Table C.2-2: Evaluated Control Options for SO_2 Emissions – Spray Dryers Nos. 1 – 8

Option No.	Control Technology
1	Fuel/Raw Material Pretreatment
2	Wet Scrubber
3	Semi-Dry Scrubber (Spray Dryer Type)
4	Dry Scrubber (Injection System)
5	Use of Natural Gas or Propane as fuel

Option 1 – Fuel/Raw Material Pretreatment

Fuel pretreatment technologies have been applied to gaseous, liquid, and solid fuels to reduce their sulfur content prior to combustion of the fuel in a processing unit, such as in fuel desulfurization. Raw materials can also be pretreated to reduce their sulfur content prior to the processing step, further reducing SO_2 emissions.

Option 2 – Wet Scrubber

Wet scrubbing systems remove SO_2 from exhaust streams by utilizing an alkaline reagent to form aqueous sulfite and sulfate salts. The reaction of SO_2 with the alkaline chemical can be performed using sodium, calcium, or dual-alkali reagents using packed bed scrubbers or spray towers. Waste treatment and disposal are required as this process generates wastewater and waste sludge when the unreacted reagents in the scrubbing liquid precipitate out during the process. The control efficiency of wet scrubber systems is considered to be 95%[4], and has been found to be technically feasible for Spray Dryer Nos. 1 – 8.

Option 3 – Semi-Dry Scrubber (Spray Dryer Type)

In a spray dryer type dry scrubbing system, a slurry of alkaline reagent, typically lime or sodium based, is atomized into the hot flue gas to absorb the sulfur dioxide. The resulting dry material is collected in a downstream particulate matter control device, typically an electrostatic precipitator or fabric filter. Lime is usually preferred as sorbent because it is more reactive than limestone and less expensive than sodium based reagents. These systems are designed for SO_2 removal efficiencies of about 80%.[5] A spray dryer type semi-dry scrubber is found to be technically feasible to control SO_2 emissions from Spray Dryer Nos. 1 – 8.

Option 4 – Dry Scrubber (Injection System)

Dry injection based dry scrubbing systems involve the direct injection of a powdered sorbent (generally lime or limestone) into the flue gas in the spray dryer. Sulfur oxides react directly with the reagent, and the dry waste is removed with particulate control equipment. Dry injection systems are usually applied when lower removal efficiencies are required or for smaller plants, but have been found to be technically feasible for application to a spray dryer with control efficiencies of about 50%[6] for SO_2.

Option 5 – Use of Natural Gas or Propane as a fuel

Natural gas is a clean fuel and is readily available in the State of Georgia. The sulfur content of natural gas and propane is lower than other fuels, and its usage keeps SO_2 emissions to a minimum. Using natural gas greatly reduces SO_2 emissions relative to

[4] Control Efficiencies as published by the Institute of Clean Air Companies (ICAC). "*Acid Gas/SO_2 Control Technologies*". http://www.icac.com/i4a/pages/index.cfm?pageid=3401

[5] Per EPA Document EPA-453/F-03-034 "*Air Pollution Control Technology Fact Sheet – Flue Gas Desulfurization*", CICA. http://www.epa.gov/ttn/catc/dir1/ffdg.pdf

[6] Control Efficiencies as published by the Institute of Clean Air Companies (ICAC). "*Acid Gas/SO_2 Control Technologies*". http://www.icac.com/i4a/pages/index.cfm?pageid=3401

burning coal. This option serves as the baseline for SO_2 BACT analysis as the source definition is based on the exclusive use of these clean-burning fuels.

Step 2: Eliminate technically infeasible options

Option 1 – Fuel/Raw Material Pretreatment

The fuel used by the spray dryers is either natural gas or propane, both of which have minimal sulfur contents and require no pretreatment. Additionally, there are no known demonstrated technologies for removing sulfur contained in kaolin clay prior to spray drying. Therefore, fuel and raw material pre-treatment is considered technically infeasible, and is no longer considered in this BACT analysis.

Step 3: Rank remaining technologies by control effectiveness

Table C.2-3: Ranking of Control Technology – Spray Dryer Nos. 1 – 8
Baseline Emissions = 2.19 tpy SO_2

Control Technology Ranking	Option No.	Control Technology	Control Efficiency	SO_2 Reductions (tpy)
1	2	Wet Scrubber	95%	2.08
2	3	Semi-Dry Scrubber (Spray Dryer)	80%	1.75
3	4	Dry Scrubber (Injection System)	50%	1.10
4	5	Use of Natural Gas or Propane as fuel	N/A	N/A

Step 4: Evaluate most effective controls and document results

Table C.2-4 below summarizes the energy, environmental, and economic impacts of all remaining control technologies.

Table C.2-4: BACT Control Analysis – Spray Dryer Nos. 1 – 8

						Change In Emissions					
Option No.	Control Technology	Annual Cost	Cost Effectiveness ($/ton SO_2 Reduced)	Total Energy Consumed (MMBtu/yr)	Water Usage (MGD)	NO_x (tpy)	VOC (tpy)	CO (tpy)	GHG (tpy CO_2e)	**SO_2 (tpy)**	Total PM[2] (tpy)
2	Wet Scrubber[1]	$1,237,492	$594,805	3,945	0.175	0	0	0	0	**-2.08**	0
3	Semi-Dry Scrubber (Spray Dryer)	$858,587	$490,061	4,947	Nil	0	0	0	0	**-1.75**	0
4	Dry Scrubber (Injection System)	$687,548	$627,897	5,424	0	0	0	0	0	**-1.10**	0
5	Use of Natural Gas or Propane as a fuel	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A

[1] This process creates "blowdown", used scrubbant containing dissolved salts at the solubility point which must be disposed of.
[2] Total PM includes filterables and condensables. All PM assumed to be <2.5 microns.

As shown in the previous table, the estimated costs exceed the level of cost effectiveness at which the installation of add-on pollution control devices can be deemed reasonable. In addition, the resources and energy that would be required to operate the control technologies are not justified based on the corresponding impacts.

Step 5: Select BACT

The exclusive use of natural gas or propane as fuel to control SO_2 emissions is proposed as BACT for Spray Dryer Nos. 1 – 8 (Emissions Unit ID Nos. SD01 – SD08) as summarized below in Table C.2-5. The proposed limitation is sufficient as BACT for SO_2 without an explicit per hourly limit in light of the minimal baseline emissions of 0.50 lb/hr.

Table C.2-5: SO_2 BACT Proposed for Spray Dryer Nos. 1 – 8

Emission Unit ID Nos.	BACT Limit (each emission unit)
SD01 – SD08	Exclusive use of natural gas or propane as fuel

C.3 SO_2 Review: Gas Fired Boiler Nos. 1 – 4

The facility is proposing to install four gas fired boilers, each with a maximum heat input of 9.8 MMBtu/hr. SO_2 emissions primarily result from the combustion of sulfur-containing fuel in the boilers. End-of-pipe control technologies, such as wet and dry scrubbing, as well as good operation practices, such as exclusive combustion of natural gas and propane, were evaluated for the control of SO_2 emissions from Boiler Nos. 1 – 4.

This analysis is based on baseline SO_2 emissions of 0.006 lb/hr or 0.025 tpy. This emission rate has been selected based on AP-42 factors for the unit's allowable fuels. For these purposes, the natural gas factor is being used as it is more conservative.

Step 1: Identify all control technologies

In reviewing the BACT alternatives to control emissions of SO_2 from the gas-fired boilers, all applicable BACT determinations and permits for commercial and institutional size boilers and furnaces have been reviewed, as summarized in Table C.3-1 below:

Table C.3-1: Summary of SO_2 Control Technology Determinations for Gas Fired Boilers

Facility Name	Location	Agency	Database	Permit Date	Process Description	Controls / Type	Emission Limits/description
Wisconsin Public Service	Marathon, WI	WI DNR	RBLC	Aug-04	Natural Gas Fired Boiler	Natural gas fuel only	0.05 lb/hr
Kern River Gas Transmission Company	Las Vegas, NV	Clark County DAQM	RBLC	May-06	Natural Gas Fired Boiler rated @ 3.85 MMBtu/hr	Low-sulfur natural gas fuel only	0.0058 lb/hr 0.0015 lb/MMBtu
Nucor Steel	Hickman, AR	AR DEQ	RBLC	May-06	Natural Gas Fired Boilers rated @ 12.6 MMBtu/hr	No Controls Specified	0.10 lb/hr 0.10 tpy 0.0006 lb/MMBtu
Harrah's Entertainment	Las Vegas, NV	Clark County DAQM	RBLC	Jan-07	Two Natural Gas Fired Boilers rated @ 35.4 MMBtu/hr each	Natural gas fuel only	0.04 lb/hr 0.001 lb/MMBtu
Daimler Chrysler Corporation	Toledo, OH	OH EPA	RBLC	Feb-09	Two Natural Gas Fired Boilers rated @ 20.4 MMBtu/hr each	No Controls Specified	0.01 lb/hr 3.64 tpy 0.0006 lb/MMBtu

[1] All Processes are type 13.310, external combustion of natural gas <100 MMBtu/hr

As a consequence of our review, and the evaluation of other available control technology options, the use of dry scrubbing, wet scrubbing, fuel/raw material pretreatment and natural gas or propane as fuel are the control technologies being evaluated as BACT as noted in Table C.3-2 below.

Table C.3-2: Evaluated Control Options for SO_2 Emissions – Gas Fired Boilers Nos. 1 – 4

Option No.	Control Technology
1	Fuel Pretreatment
2	Wet Scrubber
3	Semi-Dry Scrubber (Spray Dryer Type)
4	Dry Scrubber (Injection System)
5	Use of Natural Gas or Propane as a fuel

Option 1 – Fuel Pretreatment

Fuel pretreatment technology is a process that removes a portion of sulfur in fuel before the combustion of the fuel in a steam generating unit.[7]

Option 2 – Wet Scrubber

Wet scrubbing systems remove SO_2 from exhaust streams by utilizing an alkaline reagent to form aqueous sulfite and sulfate salts. The reaction of SO_2 with the alkaline chemical can be performed using sodium, calcium, or dual-alkali reagents using packed bed scrubbers or spray towers. Waste treatment and disposal are required as this process generates wastewater and waste sludge when the unreacted reagents in the scrubbing liquid precipitate out during the process. The control efficiency of wet scrubber systems is considered to be 95%,[8] and has been found to be technically feasible for Gas-Fired Boiler Nos. 1 – 4.

Option 3- Semi-Dry Scrubber (Spray Dryer Type)

In a spray dryer type dry scrubbing system, a slurry of alkaline reagent, typically lime or sodium based, is atomized into the hot flue gas to absorb the sulfur dioxide. The resulting dry material is collected in a downstream particulate matter control device, typically an electrostatic precipitator or fabric filter. Lime is usually preferred as the sorbent because it is more reactive than limestone and less expensive than sodium based reagents. These systems are designed for SO_2 removal efficiencies of about 80%.[9] A spray dryer type semi-dry scrubber is found to be technically feasible to control SO_2 emissions from the four Gas Fired Boilers.

Option 4- Dry Scrubber (Injection System)

Dry injection based dry scrubbing systems involve the direct injection of a powdered sorbent (generally lime or limestone) into the flue gas in the boiler. Sulfur oxides react directly with the reagent, and the dry waste is removed by particulate control equipment. Dry injection systems are usually applied when lower removal efficiencies are required or

[7] As defined in 40 CFR 60.41b

[8] Control Efficiencies as published by the Institute of Clean Air Companies (ICAC). "*Acid Gas/SO_2 Control Technologies*". http://www.icac.com/i4a/pages/index.cfm?pageid=3401

[9] Per EPA Document EPA-453/F-03-034 "*Air Pollution Control Technology Fact Sheet – Flue Gas Desulfurization*", CICA. http://www.epa.gov/ttn/catc/dir1/ffdg.pdf

for smaller plants, but have been found to be technically feasible for application to a gas-fired boiler, and have control efficiencies of about 50%[10] for SO_2.

Option 5 – Use of Natural Gas or Propane as a fuel

Natural Gas is a clean fuel and is readily available in Georgia. The sulfur content of natural gas and propane is lower than other fuels, and its usage keeps SO_2 emissions to a minimum. Using natural gas greatly reduces SO_2 emissions relative to burning coal. This option serves as the baseline for SO_2 BACT analysis as the source definition is based on the exclusive use of these clean-burning fuels.

Step 2: Eliminate technically infeasible options

Option 1 – Fuel Pretreatment

The fuel used in the gas-fired boilers is either natural gas or propane, both of which have minimal sulfur contents, and require no pretreatment. Therefore, fuel pre-treatment is considered technically infeasible, and is no longer considered in this BACT analysis.

Step 3: Rank remaining technologies by control effectiveness

Table C.3-3: Ranking of Control Technology – Gas Fired Boilers Nos. 1 – 4
Baseline Emissions = 0.025 tpy SO_2

Control Technology Ranking	Option No.	Control Technology	Control Efficiency	SO_2 Reductions (tpy)
1	2	Wet Scrubber	95%	0.024
2	3	Dry Scrubber (Spray Dryer)	80%	0.020
3	4	Dry Scrubber (Injection System)	50%	0.013
4	5	Use of Natural Gas or Propane as fuel	N/A	N/A

Step 4: Evaluate most effective controls and document results

Table C.3-4 below summarizes the energy, environmental, and economic impacts of all remaining control technologies.

[10] Control Efficiencies as published by the Institute of Clean Air Companies (ICAC). "*Acid Gas/SO_2 Control Technologies*". http://www.icac.com/i4a/pages/index.cfm?pageid=3401

Table C.3-4: BACT Control Analysis – Gas Fired Boiler Nos. 1 – 4

						Change in Emissions					
Option No.	Control Technology	Annualized Cost	Cost Effectiveness (\$/ton SO_2 Reduced)	Total Energy Consumed (MMBtu/yr)	Water Usage (MGD)	NO_x (tpy)	VOC (tpy)	CO (tpy)	GHG (tpy CO_2e)	**SO_2 (tpy)**	Total PM[2] (tpy)
2	Wet Scrubber[1]	\$277,829	\$11,698,045	219	0.009	0	0	0	0	**-0.024**	0
3	Semi-Dry Scrubber (Spray Dryer)	\$213,207	\$10,660,369	257	Nil	0	0	0	0	**-0.020**	0
4	Dry Scrubber (Injection System)	\$241,377	\$19,310,180	246	0	0	0	0	0	**-0.013**	0
5	Use of Natural Gas or Propane as a fuel	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A

[1] This process creates "blowdown", used scrubbant containing dissolved salts at the solubility point which must be disposed of.
[2] Total PM includes filterables and condensables. All PM assumed to be <2.5 microns.

As shown in the previous table, the estimated costs exceed the level of cost effectiveness at which the installation of add-on pollution control devices can be deemed reasonable. In addition, the resources and energy that would be required to operate the control technologies are not justified based on the corresponding impacts.

Step 5: Select BACT

The exclusive use of natural gas or propane as a fuel to control SO_2 emissions is proposed as BACT for Gas Fired Boiler Nos. 1 – 4 (Emissions Unit ID Nos. BLR1 – BLR4), as summarized in Table C.3-5 below.

Table C.3-5: SO_2 BACT Proposed for Gas Fired Boilers Nos. 1 – 4

Emission Unit ID Nos.	BACT Limit (each emission unit)
BLR1 – BLR4	Exclusive use of natural gas or propane as fuel

C.4 SO_2 Review: Emergency Generators Nos. 1 – 4

The facility is proposing to install four (4) diesel-fired emergency generators driven by engines rated at 2,280 kW (3,058 bhp) each. SO_2 emissions are emitted from the diesel-fired emergency generators due to the combustion of diesel fuel as a result of thermal oxidation of the sulfur contained within the fuel. End-of-pipe control technologies, such as wet and dry scrubbing, as well as good operation practices, such as exclusive combustion of ultra-low sulfur diesel, were evaluated for the control of SO_2 emissions from the four (4) diesel-fired emergency generators.

In accordance with the engine manufacturer's specifications and current federal requirements for off-road diesel fuel, baseline emissions for this analysis are calculated based on the exclusive use of Ultra-Low Sulfur Diesel fuel (ULSD) with a maximum sulfur content of 15 ppm (0.0015%).

<u>Step 1: Identify all control technologies</u>

In reviewing the BACT alternatives to control emissions of SO_2 from the emergency generators, all applicable BACT determinations and permits for Diesel Fired Internal Combustion Engines of comparable ratings have been reviewed, as summarized in Table C.4-1 below:

Table C.4-1: Summary of SO_2 Control Technology Determinations for Emergency Diesel Generators

Facility Name	Location	Database	Permit Date	Process Description	Controls / Type	Emission Limits/description		Emission Limit g/hp-hr Equivalent[2] (g/hp-hr)	Comments
Cardinal FG Co./ Cardinal Glass Plant	Bryan, OK	RBLC	Mar-03	IC Engines, Emergency Generators (2)	Low sulfur fuel, < 0.05% S	0.05	lb/MMBtu	0.159	Sulfur in fuel limit not specified.
Duke Energy Washington County Llc	Washington, OH	RBLC	Aug-03	Emergency Diesel-Fired Generator	Low sulfur fuel, combustion control	0.4	lb/hr	0.225	Sulfur in fuel limit not specified.
Maidsville	Monongahela, WV	RBLC	Mar-04	Emergency Generator	Sulfur content in the fuel limited to 0.05% by weight	6.5	lb/hr	2.73	Sulfur in fuel is not a permit limit but permit limit based on 0.05% wt. sulfur in fuel.
Marathon Petroleum Company, LLC	Garyville, LA	RBLC	Dec-06	Two Diesel fired emergency generators each rated at 671 hp	Use of diesel with a sulfur content of 15 ppmv or less	0.02	lb/hr	0.014	Permitted for 182 hours of operation per year each
ADM Corn Processing - Cedar Rapids	Linn, IA	RBLC	Jun-07	Emergency Generator	Burn low-sulfur diesel fuel. 0.05% by weight or less not to exceed the NSPS requirement.	0.17	g/bhp-hr	0.170	Sulfur in fuel limit not specified.
Archer Daniels Midland	Madill, OK	RBLC	Jun-07	Three Emergency Generators rated at 1500 kW each, and one rated at 2000 kW	Low sulfur fuel, < 0.05% S	0.170 0.180	g/bhp-hr tpy	0.140	Sulfur in fuel limit not specified.
Tate & Lyle Indgredients Americas, Inc.	Webster, IA	RBLC	Sept-08	Emergency Generator	Fuel sulfur limit	0.23	g/kW-hr	0.172	Sulfur in fuel limit not specified. However, g/kW-hr limit is 0.23.
Shady Hills Power Company Generating Station	Spring Hill, FL	RBLC	Jan-09	Emergency Generator rated at 2.5 MW	Firing Ultra-Low Sulfur Oil	0.0015	%S by weight	-	Operate less than 500 hours per consecutive 12 month period
Associated Electric Cooperative, Inc.	Chouteau, OK	RBLC	Jan-09	Emergency Generator rated at 2200 hp	Low sulfur fuel, < 0.05% S	0.089	lbs/hr	0.018	Sulfur in fuel limit pecified.
Tate & Lyle Indgredients Americas, Inc.	Webster, IA	RBLC	Sept-09	Emergency generator rated at 700 kW	Fuel Sulfur Limit	0.23 0.09	g/kW-hr tpy	0.172	Sulfur in fuel limit not specified.
MGM Mirage	Las Vegas, NV	RBLC	Nov-09	Two Diesel fired emergency generators each rated at 2206 hp	Low sulfur fuel, < 0.03% S	0.0002 0.054	lb/hp-hr lb/hr	0.0002	Operating hours restricted to one hour per day and 52 hours per year for each unit

[1] All process types are 17.11, large internal combustion engines (diesel)
[2] Conversions assume 100% efficiency for energy conversion, and 7,000 Btu/hp-hr as stated in AP-42 Chapter 3.3, Table 3.3-1, Footnote A

As a consequence of our review, and the evaluation of other available control technology options, the use of dry scrubbing, wet scrubbing, fuel/raw material pretreatment, and Low Sulfur Diesel as fuel are the control technologies being evaluated as BACT as noted in Table C.4-2 below.

Table C.4-2: Evaluated Control Options for SO_2 Emissions – Emergency Generators Nos. 1 – 4

Option No.	Control Technology
1	Wet Scrubber
2	Semi-Dry Scrubber (Spray Dryer Type)
3	Dry Scrubber (Injection System)
4	Exclusive use of Ultra-Low Sulfur Fuel

Option 1 – Wet Scrubber

Wet scrubbing systems remove SO_2 from exhaust streams by utilizing an alkaline reagent to form aqueous sulfite and sulfate salts. The reaction of SO_2 with the alkaline chemical can be performed using sodium, calcium, or dual-alkali reagents using packed bed scrubbers or spray towers. Waste treatment and disposal are required as this process generates wastewater and waste sludge when the unreacted reagents in the scrubbing liquid precipitate out during the process. The control efficiency of wet scrubber systems is considered to be 95%,[11] and has been found to be technically feasible for Diesel-Fired Emergency Generator Nos. 1 – 4.

Option 2- Semi-Dry Scrubber (Spray Dryer Type)

In a spray dryer type dry scrubbing system, a slurry of alkaline reagent, typically lime or sodium based, is atomized into the hot flue gas to absorb the sulfur dioxide. The resulting dry material is collected in a downstream particulate matter control device, typically an electrostatic precipitator or fabric filter. Lime is usually preferred as the sorbent because it is more reactive than limestone and cheaper than sodium based reagents. These systems are designed for SO_2 removal efficiencies of about 80%.[12] A spray dryer type semi-dry scrubber is found to be technically feasible to control SO_2 emissions from the four diesel-fired emergency generators.

Option 3- Dry Scrubber (Injection System)

Dry injection based dry scrubbing systems involve the direct injection of a powdered sorbent (generally lime or limestone) into the flue gas in the emergency generators. Sulfur oxides react directly with the reagent, and the dry waste is removed by particulate control equipment. Dry injection systems are usually applied when lower removal efficiencies are required or for smaller plants, but have been found to be technically

[11] Control Efficiencies as published by the Institute of Clean Air Companies (ICAC). "*Acid Gas/SO_2 Control Technologies*". http://www.icac.com/i4a/pages/index.cfm?pageid=3401

[12] Per EPA Document EPA-453/F-03-034 "*Air Pollution Control Technology Fact Sheet – Flue Gas Desulfurization*", CICA. http://www.epa.gov/ttn/catc/dir1/ffdg.pdf

feasible for application to diesel-fired emergency generators, and have control efficiencies of about 50%[13,14] for SO_2.

Option 5 – Exclusive use of Ultra-Low Sulfur Diesel Fuel

The sulfur content of the fuel used in the diesel-fired emergency generators will be limited to 0.0015% by weight to keep SO_2 emissions to a minimum. Due to the generators being operated during emergencies only, and the economic infeasibility of other control technologies, the facility will accept federally enforceable permit conditions restricting Diesel Fired Emergency Generator Nos. 1 – 4 to 0.0015 wt.% sulfur in fuel.

Step 2: Eliminate Technically infeasible options

All the above control technologies are deemed technically feasible.

Step 3: Rank remaining technologies by control effectiveness

Table C.4-3: Ranking of Control Technology – Emergency Generators Nos. 1 – 4
Baseline Emissions = 0.0078 tpy SO_2

Control Technology Ranking	Option No.	Control Technology	Control Efficiency	SO_2 Reductions (tpy)
1	1	Wet Scrubber	95%	0.0074
2	2	Dry Scrubber (Spray Dryer)	80%	0.0062
3	3	Dry Scrubber (Injection System)	50%	0.0039
4	4	Exclusive use of Ultra-Low Sulfur Fuel	N/A	N/A

Step 4: Evaluate most effective controls and document results

Table C.4-4 below summarize the energy, environmental, and economic impacts of all remaining control technologies.

13 Per EPA Document EPA-453/F-03-034 "*Air Pollution Control Technology Fact Sheet – Flue Gas Desulfurization*", CICA. http://www.epa.gov/ttn/catc/dir1/ffdg.pdf
14 Control Efficiencies as published by the Institute of Clean Air Companies (ICAC). "*Acid Gas/SO_2 Control Technologies*". http://www.icac.com/i4a/pages/index.cfm?pageid=3401

Table C.4-4: BACT Control Analysis – Emergency Generators Nos. 1 – 4

						Change in Emissions					
Option No.	Control Technology	Annualized Cost	Cost Effectiveness ($/ton SO_2 Reduced)	Total Energy Consumed (MMBtu/yr)	Water Usage (MGD)	NO_x (tpy)	VOC (tpy)	CO (tpy)	GHG (tpy CO_2e)	**SO_2 (tpy)**	Total PM[2] (tpy)
2	Wet Scrubber[1]	$579,163	$78,159,645	80.6	0.061	0	0	0	0	**-0.0074**	0
3	Semi-Dry Scrubber (Spray Dryer)	$376,503	$60,336,960	94.3	Nil	0	0	0	0	**-0.0062**	0
4	Dry Scrubber (Injection System)	$311,720	$79,928,174	66.8	0	0	0	0	0	**-0.0039**	0
5	Use of Ultra-Low-Sulfur Diesel as fuel	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A

[1] This process creates "blowdown", used scrubbant containing dissolved salts at the solubility point which must be disposed of.
[2] Total PM includes filterables and condensables. All PM assumed to be <2.5 microns.

As shown in the previous table, the estimated costs exceed the level of cost effectiveness at which the installation of add-on pollution control devices can be deemed reasonable. In addition, the resources and energy that would be required to operate the control technologies are not justified based on the corresponding impacts.

Step 5: Select BACT

The exclusive use of ultra-low sulfur diesel fuel with a federally enforceable limit of 0.0015 wt.% sulfur, and a per-unit limitation of 500 hours of operation per year is proposed as BACT to control SO_2 emissions from Diesel-Fired Emergency Generator Nos. 1 – 4 (Emissions Unit ID Nos. EDG1 – EDG4), as summarized in Table C.4-5 below.

Table C.4-5: SO_2 BACT Proposed for Diesel Fired Emergency Generators Nos. 1 – 4

Emission Unit ID Nos.	BACT Limit (each emission unit)
EDG1 – EDG4	Limit sulfur in fuel to 0.0015 wt. % and limit operation to a maximum 500 hours per year each.

Table C.5-1: SO_2 BACT Cost Analysis for Wet Scrubbers on Spray Dryer Nos. 1 – 8 (each)

Expense		Scaled Cost	Comments
Capital Costs			
Direct Costs			
	Purchased Equipment Cost (PEC)		
	Scrubber & Accessories	$272,808	Per vendor quote; see Table C.5-1a for details
	Ductwork	$307,229	
	Electrical	$87,454	
	Safety and Security	$10,940	
	Tanks	$90,473	
	Pumps	$104,885	
	Air Compressor/Receiver	$52,630	
	Oxidation System	$44,301	
	Other Equipment	$124,439	
	Feight	$30,312	
	Total Purchased Equipment Cost:	**$1,125,472**	
	Direct Installation Cost (DIC)		
	Site Preparation	$248,308	Per vendor quote; see Table C.5-1a for details
	Foundations and Supports	$286,483	
	Electrical and Instrumentation	$592,794	
	Piping	$182,784	
	Spare Parts	$56,978	
	Total Direct Installation Costs	**$1,367,347**	
	Total Direct Costs (TDC):	**$2,492,819**	**TDC=PEC+DIC**
Indirect Costs			
	Engineering	$778,313	Per vendor quote; see Table C.5-1a for details
	Start-Up	$195,393	
	Contractor Fees	$3,517,337	
	Contingency and Taxes	$618,206	
	Total Indirect Costs (TIC):	**$5,109,250**	
	Total Capital Costs:	**$7,602,068**	**TCC=TDC+TIC**
Annual Costs			
	Operating Labor @ $30/hr	$16,425	0.5 hour of Labor per 8-hour shift with 1,095 shifts/year; per EPA Cost Manual Section 5.2, Table 1.4 Labor Cost = shifts * hours/shift * hourly rate
	Maintenance Labor @ $33/hr	$18,068	
	Maintenance Materials	$18,068	100% of Maintenance Labor per EPA Cost Manual Section 5.2, Table 1.4
	Supervisory Labor	$2,464	15% of Operating Labor; per EPA Cost Manual Section 5.2, Table 1.4
	Electricity	$65,818	MCI Orange project indicated incremental power demand of 145.5 HP, assuming 0.746 kW/HP. Consumption was scaled based on ratio of exhaust flow rates; assumes 8,760 hrs/yr operation. Electricity rate is $0.056/kWh. Electricity Cost = (145.5 HP * 0.746 kW/H * 8,760 hr/yr * $0.052/kWh * (46,000/37,000)
	Caustic	$1,772	Caustic usage of 164.5 tons/year at $297/ton was scaled based on mass ratio of gases controlled. Ratio of HF, HCl and SO_2 controlled is 2.08/57.3. Caustic Cost = (SO_2 Emissions Reduction, tpy)/57.35 * 164.5 * $297/ton
	Water	$19,135	Water usage based on quench evaporation and blowdown requirements as calculated for the NO_x wet scrubber scaled relative to flow rate of calciner; water price is $0.30/kgal
	Insurance and Administrative Expenses	$228,062	3% of TCC per EPA Cost Manual Section 5.2, Table 1.4
	Overhead	$33,014	60% of Labor and utilities as specified in EPA Cost Manual Section 5.2, Table 1.4
	Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
	Capital Recovery Costs	$834,666	Calculated using EPA Cost Manual Section 1, Eqn. 2.8 Capital Recovery Cost = Capital Recovery Factor * TCC
Total Annual Costs:		**$1,237,492**	
	SO_2 Emissions Reductions (tpy)	2.08	Based on potential uncontrolled SO_2 emission rate 2.19 tpy with a control efficiency of 95%
Control Cost ($/ton SO_2 abated)		**$594,805**	

Table C.5-1a: SO_2 Detailed Budetary Capital Cost Analysis for Wet Scrubbers on Spray Dryer Nos. 1 – 8 (each)

Per BE&K Engineering estimate on MCI Orange Project for Carbo Ceramics, McIntyre, GA, July, 19, 2010
Unless otherwise noted, scaled costs are scaled from 37,000 acfm to 46,000 acfm using "6/10th rule":
(Cost A = Cost B (Flow Rate A/Flow Rate B)$^{0.6}$)

Equipment	Equipment Cost	Notes	Vendor Source
Direct Costs			
Detailed Purchased Equipment Costs (PEC)			
Scrubbers/Scrubber Accessories			
Scrubber	$169,400		Turbosonic
ID Fan	$70,000	Includes fan, motor, and inlet box	Carbo Ceramics
Total Cost of Scrubber:	**$239,400**		
Scaled Cost of Scrubber:	**$272,808**		
Additional Necessary Equipment Not Included In Scrubber Cost			
Ductwork			
Additional Ductwork	$116,700		Warren
Dampers & Expansion Joints	$47,605		Air Techniques
Stack Liner	$105,300		Warren
Total Cost of Ductwork:	**$269,605**		
Scaled Cost of Ductwork:	**$307,229**		
Electrical			
Motor Control Center, Starters and Breaker	$76,744		BE&K
Total Cost of Electrical:	**$76,744**		
Scaled Cost of Electrical:	**$87,454**		
Safety/Security			
Eye Wash and Shower No. 1 and 2	$6,600		Bradley
Entrance Security Camera, Phone, and Card Reader	$3,000		Allowance
Total Cost of Safety/Security:	**$9,600**		
Scaled Cost of Safety/Security:	**$10,940**		
Tanks			
50% Caustic Storage Tank	$43,883	Including insulation	Addison Fabricators
Heat Tracing	$35,511		Delta-Therm
Total Cost of Tanks:	**$79,394**		
Scaled Cost of Tanks:	**$90,473**		
Pumps			
Caustic Pumps	$21,716	Includes motor	GPM Industries
Header and Standby Recycle Pumps	$33,750	4 header pumps, 1 standby recycle pump	Turbo Sonic
Sump Pumps	$26,575	Includes 5 sumps pumps at $5,315 each	Blake & Pendleton
Booster Pump	$5,000	Includes motor	BE&K
Filter	$5,000	For suction line of recycle pumps	
Total Cost of Pumps:	**$92,041**		
Scaled Cost of Pumps:	**$104,885**		
Air Compressor/Receiver			
Air Compressor	$41,396	Includes motor	Blake & Pendleton
Process Air Receiver	$4,789		
Total Cost of Air Compressor/Receiver:	**$46,185**		
Scaled Cost of Air Compressor/Receiver:	**$52,630**		
Oxidation System			
Oxidation Tank	$29,700		Turbosonic
Oxidation Tank Blower System			Air Systems Engineering
Oxidation Tank Pump	$9,176	Includes motor	GPM Industries
Total Cost of Oxidation	**$38,876**		
Scaled Cost of Oxidation	**$44,301**		
Other Equipment			
Water Supply System	$20,000	For potable water supply to area	Carbo Ceramics
Scrubber Seal Pot	$6,600		BE&K
Vendor Service	$22,500		-
Miscellaneous	$60,100		-
Total Cost of Other Equipment:	**$109,200**		
Scaled Cost of Other Equipment:	**$124,439**		
Freight			
Freight	$26,600		-
Total Cost of Freight:	**$26,600**		
Scaled Cost of Freight:	**$30,312**		
Total PEC:	**$987,645**		
Scaled PEC:	**$1,125,472**		

Table C.5-1a: SO_2 Detailed Budetary Capital Cost Analysis for Wet Scrubbers on Spray Dryer Nos. 1 – 8 (each)

Equipment	Equipment Cost	Included in Quote
Direct Costs Continued		
Detailed Direct Installation Costs (DIC)		
All DIC Costs are Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility		
Site Preparation		
Site work, demolition, and earthwork	$217,900	Site preparation, paving and surfacing, underground utilities, erosion control
Total Cost of Site Preparation:	**$217,900**	
Scaled Cost of Site Preparation:	**$248,308**	
Foundations & Supports		
Concrete	$94,300	Insulation, foundation, concrete wall, pier, stair footing, equipment pads
Structural Steel	$157,100	Steel, grating, handrail, treads
Total Cost of Foundations & Supports:	**$251,400**	
Scaled Cost of Foundations & Supports:	**$286,483**	
Electrical and Instrumentation		
Electrical	$362,300	Feeders, motor control stations, caustic tank electric heat tracing, lighting, baghouse control system wiring, I/O rack communication and power
Instrumentation	$157,900	Field devices, tubing, freight, calibration, control systems
Total Cost of Electrical/Instrumentation:	**$520,200**	
Scaled Cost of Electrical/Instrumentation:	**$592,794**	
Piping		
Process Piping	$160,400	
Total Cost of Piping:	**$160,400**	
Scaled Cost of Piping:	**$182,784**	
Spare Parts		
Capitalized Spares	$50,000	
Total Cost of Spare Parts:	**$50,000**	
Scaled Cost of Spare Parts:	**$56,978**	
Total Direct Installation Cost (DIC):	**$1,199,900**	
Scaled Direct Installation Cost (DIC):	**$1,367,347**	
Total Direct Cost (TDC):	**$2,492,819**	
Indirect Costs (IC)		
All IC Costs are Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility		
Engineering		
Architectural	$181,900	Maintenance building, office, lab, electrical , restrooms, painting, doors, furnishings, plumbing, fire protection, HVAC
Design Engineering	$501,100	
Total Cost of Engineering:	**$683,000**	
Scaled Cost of Engineering:	**$778,313**	
Start-Up		
Start-up	$4,300	
Design Firm Assistance during start-up	$75,165	Not included in BE&K estimate; necessary for the project based on past experience on comparable jobs. Design firm assistance is 15% of design enegineering cost.
Wastewater and Air Pollution Control Consultant Assistance during start-up	$75,000	
Stack Testing	$12,000	
Other Testing	$5,000	
Total Cost of Start-Up:	**$171,465**	
Scaled Cost of Start-Up:	**$195,393**	
Contractor Fees		
Site Preparation Labor	$404,600	
Foundations & Supports Labor	$243,100	
Equipment Labor	$185,600	
Piping Labor	$525,000	
Electrical Labor	$633,100	
Start-Up Labor	$10,500	
Subcontractor Costs	$875,700	
Owner's Cost	$164,000	
Construction Management	$45,000	
Total Cost of Contractor Fees:	**$3,086,600**	
Scaled Cost of Contractor Fees:	**$3,517,337**	
Contingency and Taxes		
Contingency @ 7.7%	$503,900	
Taxes @ 0.6%	$38,600	
Total Cost of Contingency and Taxes:	**$542,500**	
Scaled Cost of Contingency and Taxes:	**$618,206**	
Total Indirect Cost (TIC):	**$5,109,250**	
Grand Total Capital Cost:	**$7,602,068**	

Table C.5-2: SO_2 BACT Cost Analysis for Semi-Dry Scrubber (Spray Dryer Type) on Spray Dryer Nos. 1 – 8 (each)

Expense	Cost	Comments
Capital Costs		
Direct Costs		
Purchased Equipment Cost (PEC)	$2,442,057	Estimated Capital Cost from a vendor quote for a control system for a boiler with an air flow rate of 37,000 acfm. Estimate includes direct installation costs but does not include freight. Costs were scaled using the "6/10th Rule", and the design flow rate of the Spray Dryers at Millen 46,000 acfm. Cost B = Cost A*(Flow Rate B/Flow Rate A)$^{0.6}$
Freight	$122,103	Assumed to be 5% of PEC per EPA Cost Manual Section 5.2, Table 1.3
Total Direct Costs:	**$2,564,160**	
Indirect Costs		
Indirect Installation Costs	$1,754,908	
Total Indirect Costs:	**$1,754,908**	
Contingency	$647,860	15% of direct + indirect costs per Chapter 6 of Plant Design and Economics for Chemical Engineers, Peters and Timmerhaus, 4th Edition
Total Capital Costs	**$4,966,928**	
Annual Costs		
Operating Labor @ $30/hr	$16,425	0.5 hour of Labor per 8-hour shift with 1,095 shifts/year; per EPA Cost Manual Section 5.2, Table 1.4 Labor Cost = shifts * hours/shift * hourly rate
Maintenance Labor @ $33/hr	$18,068	
Maintenance Materials	$18,068	100% of Maintenance Labor per EPA Cost Manual Section 5.2, Table 1.4
Supervisory Labor	$2,464	15% of Operating Labor; per EPA Cost Manual Section 5.2, Table 1.4
Electricity (kW-hr/yr)	$75,366	As estimated from a vendor quote for a similar control system for a boiler with an air flow rate of 37,000 acfm and 127kW operating load
Lime Reagent (tons/year)	$830	Vendor estimated Lime usage at $134,138 annually with for SO_2 emissions of 80.85 lb/hr. Lime usage was scaled based on ratio of SO_2 uncontrolled emissions.
Water	$3.34	Based on lime consumption estimated above and assumption of lime slurry being made up with 10% solids content; water priceis $0.30/kgal
Overhead	$33,014	60% of Labor and utilities as specified in EPA Cost Manual Section 5.2, Table 1.4
Insurance and Administrative	$149,008	3% of TCC per EPA Cost Manual Section 5.2, Table 1.4
Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery Costs (15 year depreciation + 7% interest)	$545,342	Calculated using EPA Cost Manual Section 1, Eqn. 2.8 Capital Recovery Cost = Capital Recovery Factor * TCC
Total Annual Cost	**$858,587**	
SO_2 Emission Reductions (Potential Emissions, tpy)	1.75	Based on 80% Control efficiency and 2.2 tpy uncontrolled SO_2 emissions
Control Costs ($/ton abated)	**$490,061**	

Table C.5-3: SO_2 BACT Cost Analysis for Injection Based Dry Scrubbers on Spray Dryer Nos. 1 – 8 (each)

Expense		Cost	Comments
Capital Costs			
Direct Costs			
	Purchased Equipment Cost (PEC)		
	Purchased Equipment Cost (PEC)	$2,025,210	See Table C.5-3a
	Total PEC	**$2,025,210**	
	Direct Installation Cost (DIC)		
	Foundations and Support	$148,142	See Table C.5-3a
	Other Equipment	$246,143	
	Piping	$5,698	
	Ductwork	$22,791	
	Controls Integration	$34,187	
	Electrical	$28,489	
	Total DIC:	**$485,449**	
	Total Direct Cost:	**$2,510,658**	
Indirect Costs			
	Start-Up Preparation	$22,791	See Table C.5-3a
	Engineering	$56,978	
	Contractor Fees	$119,653	
	Total Indirect Cost	**$199,421**	
	Contingency	$406,512	See Table C.5-3a
	Lost Production	$525,000	
Total Capital Costs		**$3,641,591**	
Annual Costs			
	Operating Labor @ $30/hr	$16,425	0.5 hour of Labor per 8-hour shift with 1,095 shifts/year; per EPA Cost Manual Section 5.2, Table 1.4 Labor Cost = shifts * hours/shift * hourly rate
	Maintenance Labor @ $33/hr	$18,068	
	Maintenance Materials	$18,068	100% of Maintenance Labor per EPA Cost Manual Section 5.2, Table 1.4
	Supervisory Labor	$2,464	15% of Operating Labor; per EPA Cost Manual Section 5.2, Table 1.4
	Electricity (kW-hr/yr)	$88,525	See Table C.5-3b
	Lime Reagent	$1,910	Vendor estimated Lime usage at $308,869 annually for SO_2 emissions of 80.85 lb/hr. Lime usage was scaled based on ratio of uncontrolled SO_2 emissions. Lime Reagent Cost = $308,869 * (0.500lb/hr / 80.85lb/hr)
	Overhead	$33,014	60% of Labor and utilities as specified in EPA Cost Manual Section 5.2, Table 1.4
	Insurance and Administrative Expenses	$109,248	3% of TCC per EPA Cost Manual Section 5.2, Table 1.4
	Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
	Capital Recovery Costs (15 year depreciation + 7% interest)	$399,827	Calculated using EPA Cost Manual Section 1, Eqn. 2.8 Capital Recovery Cost = Capital Recovery Factor * TCC
Total Annual Costs		**$687,548**	
	SO_2 Emission Reductions (tpy)	1.10	Based on potential uncontrolled SO_2 emission rate 2.19 tpy with a control efficiency of 50%
Control Costs($/ton SO_2 abated)		**$627,897**	

Table C.5-3a: SO_2 Detailed Budetary Cost Analysis for Injection Based Dry Scrubbers

Estimated by TMTS Associates based on a 2009 quote from Fuel Tech High Inc. for Dry Lime Injection.
Unless otherwise noted, scaled costs are scaled from 37,000 acfm to 46,000 acfm using "6/10th rule":
(Cost A = Cost B (Flow Rate A/Flow Rate B) $^{0.6}$ ***)***

Equipment	Budgetary Cost	Notes	Source
Direct Costs			
Purchased Equipment Costs (PEC)			
Purchased Equipment Costs (PEC)			
Injection Based Dry Scrubber	$1,777,200	Estimated Capital Cost from a vendor quote for a control system for a boiler with an airflow rate of 37,000 acfm.	Fuel Tech
Total PEC:	**$1,777,200**		
Scaled PEC:	**$2,025,210**		
PEC:	**$2,025,210**		
Direct Installation Costs (DIC)			
Foundations and Support			
Foundations/ roadways	$50,000	Assumes use of slab-not pilings	Estimated by CARBO project engineering
Structural Steel	$80,000	Belt support, dust collector support, duct, pipe supports, Waste Hopper cover	Estimated by CARBO project engineering
Total Cost of Foundations/Support:	**$130,000**		
Scaled Cost of Foundations/Support:	**$148,142**		
Other Equipment			
Nuisance Dust Collector	$36,000		Comparable Experience on other jobs
Broken Bag detectors (2)	$9,000		Recent quote
Nuisance collector stack	$15,000		Estimated by CARBO project engineering
Belt Conveyor	$80,000	Air supported belt conveyor 24"x 66', 3 hp	Comparable experience on other jobs - costing developed by CARBO project engineers
Spare Parts	$40,000		
Waste Hoppers	$36,000	20 yard capacity with cover and teflon liner, quantity of 3 @ $12,000 ea.	Estimated by CARBO project engineering
Total Cost of Other Equipment:	**$216,000**		
Scaled Cost of Other Equipment:	**$246,143**		
Piping			
Piping	$5,000	Air	Estimated by CARBO project engineering
Total Cost of Piping:	**$5,000**		
Scaled Cost of Piping:	**$5,698**		
Ductwork			
Ductwork	$20,000	For Nuisance Dust	Estimated by CARBO project engineering
Total Cost of Ductwork:	**$20,000**		
Scaled Cost of Ductwork:	**$22,791**		
Controls Integration			
Controls Integration	$30,000	Includes HMI/Graphics development, logic programming for extra items outside of vendor scope	
Total Cost of Controls Integration:	**$30,000**		
Scaled Cost of Controls Integration:	**$34,187**		
Electrical			
4 motors, 6 devices	$20,000		Estimated by CARBO project engineering
Yard and Local Lighting	$5,000	Includes 2 pole mounted HPS at 40' high and 2 LPS area lights	
Total Cost of Electrical:	**$25,000**		
Scaled Cost of Electrical:	**$28,489**		
Total DIC:	**$485,449**		
Total Direct Cost:	**$2,510,658**		

Table C.5-3a: SO_2 Detailed Budetary Cost Analysis for Injection Based Dry Scrubbers

Estimated by TMTS Associates based on a 2009 quote from Fuel Tech High Inc. for Dry Lime Injection.
Unless otherwise noted, scaled costs are scaled from 37,000 acfm to 46,000 acfm using "6/10th rule":
(Cost A = Cost B (Flow Rate A/Flow Rate B)$^{0.6}$)

Equipment	Budgetary Cost	Notes	Source
Indirect Costs			
Start-Up Preparation			
Stack Testing	$20,000		
Total Cost of Start-Up Preparation:	**$20,000**		
Scaled Cost of Start-Up Preparation:	**$22,791**		
Engineering			
Detailed Design and Engineering Review of Detailed Design	$50,000		
Total Cost of Engineering:	**$50,000**		
Scaled Cost of Engineering:	**$56,978**		
Contractor Fees			
Project Management for 4 months	$80,000		
Labor for Setting/Installation	$25,000	For nuisance collector, conveyor etc	Estimated by CARBO project engineering
Total Cost of Contractor Fees:	**$105,000**		
Scaled Cost of Contractor Fees:	**$119,653**		
Total Indirect Cost:	**$199,421**		
Contingency @ 15%	$406,512	15% of direct + indirect costs	Chapter 6 of Plant Design and Economics for Chemical Engineers, Peters and Timmerhaus, 4th Edition
Cost of Lost Production	$525,000		
Grand Total Capital Cost:	**$3,641,591**		

Table C.5-3b: SO_2 BACT Energy Cost Analysis for Injection Based Dry Scrubber for Spray Dryer Nos. 1 – 8 (each)

Gas flowrate:	46,000	[acfm]
Reference temperature:	77	[^oF]
Inlet gas temperature (after baghouse):	180	[^oF]
Gas flowrate:	38,593	[scfm]

	Average Unit Cost[1]	Energy Required	No. Hours per Year[2]		
Incremental Electricity at ID Fan[3,4]	0.056 $/kWh	128 kW	8,592	$	61,226.88
Direct System Load[5]	0.056 $/kWh	56 kW	8,760	$	27,297.82
Total Annual Electricity Usage:	1,589,312 kWh/yr			$	88,524.70

Footnotes	
1	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
2	ID fan load assumes 8,760 hour per year potential minus one week (7 days * 24 hours) annual downtime for system maintenance and repair. Direct system load includes freeze protection and related heaters and so is assumed 8,760 hr/year.
3	Incremental electricity required to compensate for additional pressure drop of control system is assumed to include additional ductwork (7"w.c.), and baghouse pressure drop (10"w.c. per vendor).
4	Power requirement calculated as specified in EPA Air Pollution Control Cost Manual, 6th Edition, Chapter 3.2, Equation 2.42, assuming 60% combined efficiency of the fan and motor.
5	Based on vendor quoted load of 45kW for equipment included in quote, scaled by ratio of quoted system flow rate (37,000 acfm) to spray dryer exhaust rate (45,000 acfm)

Table C.5-4: Energy and Environmental Impact Summary for Spray Dryer Nos. 1 – 8 (each)

	Resource Consumption			Energy Equivalents	
Control Technology	Water (MGD)[1]	Gas (Mscf/yr)[1]	Electricity (kWh/yr)[1]	Total Energy Consumed (MMBtu/yr)[2]	Total Energy Consumed (MMBtu/hr)[3]
Wet Scrubber	0.175	0	1,181,653	4,033	0.460
Semi-Dry Scrubber	3.05E-05	0	1,449,341	4,947	0.565
Dry Scrubber (Injection System)	0	0	1,589,312	5,424	0.619
Use of Natural Gas or Propane as a fuel	0	0	0	0	0

	Collateral Emissions					
Control Technology	NO_x (tpy)[4]	GHG (tpy CO_2e)[5]	CO (tpy)[6]	VOC (tpy)[7]	SO_2 (tpy)[8]	Total PM (tpy)[9,10]
Wet Scrubber	0.000	0.000	0.000	0.000	0.000	0.000
Semi-Dry Scrubber	0.000	0.000	0.000	0.000	0.000	0.000
Dry Scrubber (Injection System)	0.000	0.000	0.000	0.000	0.000	0.000
Use of Natural Gas or Propane as a fuel	0.000	0.000	0.000	0.000	0.000	0.000

Notes	
1	Per cost-effectiveness calculation sheets.
2	Total Energy Consumed, MMBtu/yr = (Gas Consumption, Mscf/yr) / (1,000 Mscf/MMscf) * (1,020 MMBtu/MMscf) + (Electricity Consumption, kWh/year) * (3413 Btu-hr/kWh) / (10^6 Btu/MMBtu)
3	Total Energy Consumed, MMBtu/hr = (Total Energy Consumed, MMBtu/yr) / (8,760 hr/yr)
4	Estimated NO_x emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1, NO_x emissions from small uncontrolled boilers. NO_x tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (100 lb NO_x/MMscf) / (2000 lb/ton)
5	Estimated greenhouse gas (GHG) emissions from natural gas combustion in control device calculated using AP-42 emission factors, 5th Edition, Table 1.4-2. Combined GHG Emission Factor, lb CO_2e/MMscf = (120,000 lb CO_2/MMscf) * (CO_2 GWP =1) + (2.2 lb N_2O/MMscf) * (N_2O GWP=310) + (2.3 lb CH4/MMscf) * (CH_4 GWP=21) GHG Emissions, tpy CO_2e = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (GHG EF=120,730 lb CO_2e/MMscf) / (2000 lb/ton)
6	Estimated CO emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1. CO, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (84 lb CO/MMscf) / (2000 lb/ton)
7	Estimated VOC emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. VOC, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (5.5 lb VOC/MMscf) / (2000 lb/ton)
8	Estimated SO_2 emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. SO_2, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (0.6 lb SO_2/MMscf) / (2000 lb/ton)
9	Estimated PM emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. PM, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (7.6 lb PM/MMscf) / (2000 lb/ton)
10	Total PM includes fiterables and condensables. All PM assumed to be <2.5

Table C.6-1: SO_2 BACT Cost Analysis for Wet Scrubbers on Boiler Nos. 1 – 4 (each)

Expense	Scaled Cost	Comments
Capital Costs		
Direct Costs		
Purchased Equipment Cost (PEC)		
Scrubber & Accessories	$47,530	Per vendor quote; see Table C.6-1a for details
Ductwork	$53,527	
Electrical	$15,237	
Safety and Security	$1,906	
Tanks	$15,763	
Pumps	$18,274	
Air Compressor/Receiver	$9,169	
Oxidation System	$7,718	
Other Equipment	$21,680	
Feight	$5,281	
Total Purchased Equipment Cost:	**$196,085**	
Direct Installation Cost (DIC)		
Site Preparation	$43,261	Per vendor quote; see Table C.6-1a for details
Foundations and Supports	$49,912	
Electrical and Instrumentation	$103,279	
Piping	$31,845	
Spare Parts	$9,927	
Total Direct Installation Costs	**$238,225**	
Total Direct Costs (TDC):	**$434,310**	**TDC=PEC+DIC**
Indirect Costs		
Engineering	$135,601	Per vendor quote; see Table C.6-1a for details
Start-Up	$34,042	
Contractor Fees	$612,806	
Contingency and Taxes	$107,707	
Total Indirect Costs (TIC):	**$890,157**	
Total Capital Costs:	**$1,324,467**	**TCC=TDC+TIC**
Annual Costs		
Operating Labor @ $30/hr	$16,425	0.5 hour of Labor per 8-hour shift with 1,095 shifts/year; per EPA Cost Manual Section 5.2, Table 1.4 Labor Cost = shifts * hours/shift * hourly rate
Maintenance Labor @ $33/hr	$18,068	
Maintenance Materials	$18,068	100% of Maintenance Labor per EPA Cost Manual Section 5.2, Table 1.4
Supervisory Labor	$2,464	15% of Operating Labor; per EPA Cost Manual Section 5.2, Table 1.4
Electricity	$3,577	MCI Orange project indicated incremental power demand of 145.5 HP, assuming 0.746 kW/HP. Consumption was scaled based on ratio of exhaust flow rates; assumes 8,760 hrs/yr operation. Electricity rate is $0.056/kWh. Electricity Cost = (145.5 HP * 0.746 kW/H * 8,760 hr/yr * $0.056/kWh * (2,500/37,000)
Caustic	$20	Caustic usage of 164.5 tons/year at $297/ton was scaled based on mass ratio of controlled SO_2 emissions is 0.024/57.3. Caustic Cost = (SO2 Emissions Reduction, tpy)/57.35 * 164.5 * $297/ton
Water	$1,040	Water usage based on quench evaporation and blowdown requirements as calculated for the NO_x wet scrubber scaled relative to flow rate of calciner; water price is $0.30/kgal
Insurance and Administrative Expenses	$39,734	3% of TCC per EPA Cost Manual Section 5.2, Table 1.4
Overhead	$33,014	60% of Labor and utilities as specified in EPA Cost Manual Section 5.2, Table 1.4
Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery Costs	$145,419	Calculated using EPA Cost Manual Section 1, Eqn. 2.8 Capital Recovery Cost = Capital Recovery Factor * TCC
Total Annual Costs:	**$277,829**	
SO_2 Emissions Reductions (tpy)	0.024	Based on potential uncontrolled SO_2 emission rate of 0.025 tpy with a control efficiency of 95%
Control Cost ($/ton SO_2 abated)	**$11,698,045**	

Table C.6-1a: SO_2 Detailed Budetary Capital Cost Analysis for Wet Scrubbers on Boiler Nos. 1 – 4 (each)

Per BE&K Engineering estimate on MCI Orange Project for Carbo Ceramics, McIntyre, GA, July, 19, 2010
Unless otherwise noted, scaled costs are scaled from 37,000 acfm to 2,500 acfm using "6/10th rule":
(Cost A = Cost B (Flow Rate A/Flow Rate B)$^{0.6}$)

Equipment	Equipment Cost	Notes	Vendor Source
Direct Costs			
Detailed Purchased Equipment Costs (PEC)			
Scrubbers/Scrubber Accessories			
Scrubber	$169,400		Turbosonic
ID Fan	$70,000	Includes fan, motor, and inlet box	Carbo Ceramics
Total Cost of Scrubber:	**$239,400**		
Scaled Cost of Scrubber:	**$47,530**		
Additional Necessary Equipment Not Included In Scrubber Cost			
Ductwork			
Additional Ductwork	$116,700		Warren
Dampers and Expansion Joints	$47,605		Air Techniques
Stack Liner	$105,300		Warren
Total Cost of Ductwork:	**$269,605**		
Scaled Cost of Ductwork:	**$53,527**		
Electrical			
Motor Control Center, Starters and Breaker	$76,744		BE&K
Total Cost of Electrical:	**$76,744**		
Scaled Cost of Electrical:	**$15,237**		
Safety/Security			
Eye Wash and Shower No. 1 and 2	$6,600		Bradley
Entrance Security Camera, Phone, and Card Reader	$3,000		Allowance
Total Cost of Safety/Security:	**$9,600**		
Scaled Cost of Safety/Security:	**$1,906**		
Tanks			
50% Caustic Storage Tank	$43,883	Including insulation	Addison Fabricators
Heat Tracing	$35,511		Delta-Therm
Total Cost of Tanks:	**$79,394**		
Scaled Cost of Tanks:	**$15,763**		
Pumps			
Caustic Pumps	$21,716	Includes motor	GPM Industries
Header and Standby Recycle Pumps	$33,750	4 header pumps, 1 standby recycle pump	Turbo Sonic
Sump Pumps	$26,575	Includes 5 sumps pumps at $5,315 each	Blake & Pendleton
Booster Pump	$5,000	Includes motor	BE&K
Filter	$5,000	For suction line of recycle pumps	
Total Cost of Pumps:	**$92,041**		
Scaled Cost of Pumps:	**$18,274**		
Air Compressor/Receiver			
Air Compressor	$41,396	Includes motor	Blake & Pendleton
Process Air Receiver	$4,789		
Total Cost of Air Compressor/Receiver:	**$46,185**		
Scaled Cost of Air Compressor/Receiver:	**$9,169**		
Oxidation System			
Oxidation Tank	$29,700		Turbosonic
Oxidation Tank Blower System			Air Systems Engineering
Oxidation Tank Pump	$9,176	Includes motor	GPM Industries
Total Cost of Oxidation	**$38,876**		
Scaled Cost of Oxidation	**$7,718**		
Other Equipment			
Water Supply System	$20,000	For potable water supply to area	Carbo Ceramics
Scrubber Seal Pot	$6,600		BE&K
Vendor Service	$22,500		-
Miscellaneous	$60,100		-
Total Cost of Other Equipment:	**$109,200**		
Scaled Cost of Other Equipment:	**$21,680**		
Freight			
Freight	$26,600		-
Total Cost of Freight:	**$26,600**		
Scaled Cost of Freight:	**$5,281**		
Total PEC:	**$987,645**		
Scaled PEC:	**$196,085**		

Table C.6-1a: SO_2 Detailed Budetary Capital Cost Analysis for Wet Scrubbers on Boiler Nos. 1 – 4 (each)

Equipment	Equipment Cost	Included in Quote
Direct Costs Continued		
Detailed Direct Installation Costs (DIC)		
All DIC Costs are Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility		
Site Preparation		
Site work, demolition, and earthwork	$217,900	Site preparation, paving and surfacing, underground utilities, erosion control
Total Cost of Site Preparation:	**$217,900**	
Scaled Cost of Site Preparation:	**$43,261**	
Foundations & Supports		
Concrete	$94,300	Insulation, foundation, concrete wall, pier, stair footing, equipment pads
Structural Steel	$157,100	Steel, grating, handrail, treads
Total Cost of Foundations & Supports:	**$251,400**	
Scaled Cost of Foundations & Supports:	**$49,912**	
Electrical and Instrumentation		
Electrical	$362,300	Feeders, motor control stations, caustic tank electric heat tracing, lighting, baghouse control system wiring, I/O rack communication and power
Instrumentation	$157,900	Field devices, tubing, freight, calibration, control systems
Total Cost of Electrical/Instrumentation:	**$520,200**	
Scaled Cost of Electrical/Instrumentation:	**$103,279**	
Piping		
Process Piping	$160,400	
Total Cost of Piping:	**$160,400**	
Scaled Cost of Piping:	**$31,845**	
Spare Parts		
Capitalized Spares	$50,000	
Total Cost of Spare Parts:	**$50,000**	
Scaled Cost of Spare Parts:	**$9,927**	
Total Direct Installation Cost (DIC):	**$1,199,900**	
Scaled Direct Installation Cost (DIC):	**$238,225**	
Total Direct Cost (TDC):	**$434,310**	
Indirect Costs (IC)		
All IC Costs are Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility		
Engineering		
Architectural	$181,900	
Design Engineering	$501,100	
Total Cost of Engineering:	**$683,000**	
Scaled Cost of Engineering:	**$135,601**	
Start-Up		
Start-up	$4,300	
Design Firm Assistance during start-up	$75,165	Not included in BE&K estimate; necessary for the project based on past experience on comparable jobs. Design firm assistance is 15% of design enegineering cost.
Wastewater and Air Pollution Control Consultant Assistance during start-up	$75,000	
Stack Testing	$12,000	
Other Testing	$5,000	
Total Cost of Start-Up:	**$171,465**	
Scaled Cost of Start-Up:	**$34,042**	
Contractor Fees		
Site Preparation Labor	$404,600	
Foundations & Supports Labor	$243,100	
Equipment Labor	$185,600	
Piping Labor	$525,000	
Electrical Labor	$633,100	
Start-Up Labor	$10,500	
Subcontractor Costs	$875,700	
Owner's Cost	$164,000	
Construction Management	$45,000	
Total Cost of Contractor Fees:	**$3,086,600**	
Scaled Cost of Contractor Fees:	**$612,806**	
Contingency and Taxes		
Contingency @ 7.7%	$503,900	
Taxes @ 0.6%	$38,600	
Total Cost of Contingency and Taxes:	**$542,500**	
Scaled Cost of Contingency and Taxes:	**$107,707**	
Total Indirect Cost (TIC):	**$890,157**	
Grand Total Capital Cost:	**$1,324,467**	

Table C.6-2: BACT SO_2 Cost Analysis for Semi-Dry Scrubber (Spray Dryer Type) on Boiler Nos. 1 – 4 (each)

Expense		Cost	Comments
Capital Costs			
Direct Costs			
	Purchased Equipment Cost (PEC)	$425,466	Estimated Capital Cost from a vendor quote for a control system for a boiler with an air flow rate of 37,000 acfm. Estimate includes direct installation costs but does not include freight. Costs were scaled using the "6/10th Rule", and the design flow rate of the Boilers at Millen 2,500 acfm. Cost B = Cost A*(Flow Rate B/Flow Rate A)$^{0.6}$
	Freight	$21,273	Assumed to be 5% of PEC per EPA Cost Manual Section 5.2, Table 1.3
Total Direct Costs:		**$446,740**	
Indirect Costs			
	Indirect Installation Costs	$305,748	
Total Indirect Costs:		**$305,748**	
	Contingency	$112,873	15% of direct + indirect costs per Chapter 6 of Plant Design and Economics for Chemical Engineers, Peters and Timmerhaus, 4th Edition
Total Capital Costs		**$865,361**	
Annual Costs			
	Operating Labor @ $30/hr	$16,425	0.5 hour of Labor per 8-hour shift with 1,095 shifts/year; per EPA Cost Manual Section 5.2, Table 1.4 Labor Cost = shifts * hours/shift * hourly rate
	Maintenance Labor @ $33/hr	$18,068	
	Maintenance Materials	$18,068	100% of Maintenance Labor per EPA Cost Manual Section 5.2, Table 1.4
	Supervisory Labor	$2,464	15% of Operating Labor; per EPA Cost Manual Section 5.2, Table 1.4
	Electricity (kW-hr/yr)	$4,187	As estimated from a vendor quote for a similar control system for a boiler with an air flow rate of 37,000 acfm and 127kW operating load Electricity Cost = 127 kW * 8760 hr/yr * (2500/37000 acfm) * $0.056/kW
	Lime Reagent (tons/year)	$9	Vendor estimated Lime usage at $134,138 annually with for SO_2 emissions of 80.85 lb/hr. Lime usage was scaled based on ratio of SO_2 uncontrolled emissions. Lime Reagent Cost = $134,138 * (0.006lb/hr / 80.85lb/hr)
	Water	$0.04	Based on lime consumption estimated above and assumption of lime slurry being made up with 10% solids content; water price is $0.30/kgal
	Overhead	$33,014	60% of Labor and utilities as specified in EPA Cost Manual Section 5.2, Table 1.4
	Insurance and Administrative	$25,961	3% of TCC per EPA Cost Manual Section 5.2, Table 1.4
	Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
	Capital Recovery Costs (15 year depreciation + 7% interest)	$95,012	Calculated using EPA Cost Manual Section 1, Eqn. 2.8 Capital Recovery Cost = Capital Recovery Factor * TCC
Total Annual Cost		**$213,207**	
	SO_2 Emissions Reductions (Potential Emissions, tpy)	0.02	Based on 80% Control efficiency and 0.025 tpy uncontrolled SO_2 emissions
Control Costs ($/ton abated)		**$10,660,369**	

Table C.6-3: SO_2 BACT Cost Analysis for Injection Based Dry Scrubbers on Boiler Nos. 1 – 4 (each)

Expense		Cost	Comments
Capital Costs			
Direct Costs			
	Purchased Equipment Cost (PEC)		
	Purchased Equipment Cost (PEC)	$352,841	See Table C.6-3a
	Total PEC	**$352,841**	
	Direct Installation Cost (DIC)		
	Foundations and Support	$25,810	See Table C.6-3a
	Other Equipment	$42,884	
	Piping	$993	
	Ductwork	$3,971	
	Controls Integration	$5,956	
	Electrical	$4,963	
	Total DIC:	**$84,577**	
	Total Direct Cost:	**$437,418**	
Indirect Costs			
	Start-Up Preparation	$3,971	See Table C.6-3a
	Engineering	$9,927	
	Contractor Fees	$20,846	
	Total Indirect Cost	**$34,744**	
	Contingency	$70,824	See Table C.6-3a
	Lost Production	$525,000	
Total Capital Costs		**$1,067,987**	
Annual Costs			
	Operating Labor @ $30/hr	$16,425	0.5 hour of Labor per 8-hour shift with 1,095 shifts/year; per EPA Cost Manual Section 5.2, Table 1.4 Labor Cost = shifts * hours/shift * hourly rate
	Maintenance Labor @ $33/hr	$18,068	
	Maintenance Materials	$18,068	100% of Maintenance Labor per EPA Cost Manual Section 5.2, Table 1.4
	Supervisory Labor	$2,464	15% of Operating Labor; per EPA Cost Manual Section 5.2, Table 1.4
	Electricity (kW-hr/yr)	$4,019	See Table C.6-3a
	Lime Reagent	$22	Vendor estimated Lime usage at $308,869 annually for SO_2 emissions of 80.85 lb/hr. Lime usage was scaled based on ratio of uncontrolled SO_2 emissions. Lime Reagent Cost = $308,869 * (0.006lb/hr / 80.85lb/hr)
	Overhead	$33,014	60% of Labor and utilities as specified in EPA Cost Manual Section 5.2, Table 1.4
	Insurance and Administrative Expenses	$32,040	3% of TCC per EPA Cost Manual Section 5.2, Table 1.4
	Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
	Capital Recovery Costs (15 year depreciation + 7% interest)	$117,259	Calculated using EPA Cost Manual Section 1, Eqn. 2.8 Capital Recovery Cost = Capital Recovery Factor * TCC
Total Annual Costs		**$241,377**	
	SO_2 Emission Reductions (tpy)	0.013	Based on potential uncontrolled SO_2 emission rate 0.025 tpy with a control efficiency of 50%
Control Costs($/ton SO_2 abated)		**$19,310,180**	

Table C.6-3a: Detailed Cost Analysis for Injection Based Dry Scrubbers from Boilers Nos. 1 – 4 (each)

Estimated by TMTS Associates based on a 2009 quote from Fuel Tech High Inc. for Dry Lime Injection.
Unless otherwise noted, scaled costs are scaled from 37,000 acfm to 2,500 acfm using "6/10th rule":
(Cost A = Cost B (Flow Rate A/Flow Rate B)$^{0.6}$)

Equipment	Budgetary Cost	Notes	Source
Direct Costs			
Purchased Equipment Costs (PEC)			
Purchased Equipment Costs (PEC)			
Injection Based Dry Scrubber	$1,777,200	Estimated Capital Cost from a vendor quote for a control system for a boiler with an airflow rate of 37,000 acfm.	Fuel Tech
Total PEC:	**$1,777,200**		
Scaled PEC:	**$352,841**		
PEC:	**$352,841**		
Direct Installation Costs (DIC)			
Foundations and Support			
Foundations/ roadways	$50,000	Assumes use of slab-not pilings	Estimated by CARBO project engineering
Structural Steel	$80,000	Belt support, dust collector support, duct, pipe supports, Waste Hopper cover	Estimated by CARBO project engineering
Total Cost of Foundations/Support:	**$130,000**		
Scaled Cost of Foundations/Support:	**$25,810**		
Other Equipment			
Nuisance Dust Collector	$36,000		Comparable Experience on other jobs
Broken Bag detectors (2)	$9,000		Recent quote
Nuisance collector stack	$15,000		Estimated by CARBO project engineering
Belt Conveyor	$80,000	Air supported belt conveyor 24"x 66', 3 hp	Based on comparable Experience on other jobs - costing developed by CARBO project engineering
Spare Parts	$40,000		
Waste Hoppers	$36,000	20 yard capacity with cover and teflon liner, quantity of 3 @ $12,000 ea.	Estimated by CARBO project engineering
Total Cost of Other Equipment:	**$216,000**		
Scaled Cost of Other Equipment:	**$42,884**		
Piping			
Piping	$5,000	Air	Estimated by CARBO project engineering
Total Cost of Piping:	**$5,000**		
Scaled Cost of Piping:	**$993**		
Ductwork			
Ductwork	$20,000	For Nuisance Dust	Estimated by CARBO project engineering
Total Cost of Ductwork:	**$20,000**		
Scaled Cost of Ductwork:	**$3,971**		
Controls Integration			
Controls Integration	$30,000	Includes HMI/Graphics development, logic programming for extra items outside of vendor	
Total Cost of Controls Integration:	**$30,000**		
Scaled Cost of Controls Integration:	**$5,956**		
Electrical			
4 motors, 6 devices	$20,000		Estimated by CARBO project engineering
Yard and Local Lighting	$5,000	Includes 2 pole mounted HPS at 40' high and 2 LPS area lights	Estimated by CARBO project engineering
Total Cost of Electrical:	**$25,000**		
Scaled Cost of Electrical:	**$4,963**		
Total DIC:	**$84,577**		
Total Direct Cost:	**$437,418**		

Table C.6-3a: Detailed Cost Analysis for Injection Based Dry Scrubbers from Boilers Nos. 1 – 4 (each)

Estimated by TMTS Associates based on a 2009 quote from Fuel Tech High Inc. for Dry Lime Injection.
Unless otherwise noted, scaled costs are scaled from 37,000 acfm to 2,500 acfm using "6/10th rule":
(Cost A = Cost B (Flow Rate A/Flow Rate B) $^{0.6}$ ***)***

Equipment	Budgetary Cost	Notes	Source
Indirect Costs			
Start-Up Preparation			
Stack Testing	$20,000		
Total Cost of Start-Up Preparation:	**$20,000**		
Scaled Cost of Start-Up Preparation:	**$3,971**		
Engineering			
Detailed Design and Engineering Review of Detailed Design	$50,000		
Total Cost of Engineering:	**$50,000**		
Scaled Cost of Engineering:	**$9,927**		
Contractor Fees			
Project Management for 4 months	$80,000		
Labor for Setting/Installation	$25,000	For nuisance collector, conveyor etc	Estimated by CARBO project engineering
Total Cost of Contractor Fees:	**$105,000**		
Scaled Cost of Contractor Fees:	**$20,846**		
Total Indirect Cost:	**$34,744**		
Contingency @ 15%	$70,824	15% of direct + indirect costs	Chapter 6 of Plant Design and Economics for Chemical Engineers, Peters and Timmerhaus, 4th Edition
Cost of Lost Production and Internal Project Costs	$525,000		
Grand Total Capital Cost:	**$1,067,987**		

Table C.6-3b: SO_2 BACT Energy Cost Analysis for Injection Based Dry Scrubber for Boiler Nos. 1 – 4 (each)

Gas flowrate:	2,500	[acfm]
Reference temperature:	77	[°F]
Inlet gas temperature (after baghouse):	380	[°F]
Gas flowrate:	1,598	[scfm]

	Average Unit Cost[1]	Energy Required	No. Hours per Year[2]		
Incremental Electricity at ID Fan[3,4]	0.056 $/kWh	5 kW	8,592	$	2,534.96
Direct System Load[5]	0.056 $/kWh	3 kW	8,760	$	1,483.58
Total Annual Electricity Usage:	72,146 kWh/yr			$	4,018.54

Footnotes	
1	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
2	ID fan load assumes 8,760 hour per year potential minus one week (7 days * 24 hours) annual downtime for system maintenance and repair. Direct system load includes freeze protection and related heaters and so is assumed 8,760 hr/year.
3	Incremental electricity required to compensate for additional pressure drop of control system is assumed to include additional ductwork (7"w.c.), and baghouse pressure drop (10"w.c. per vendor).
4	Power requirement calculated as specified in EPA Air Pollution Control Cost Manual, 6th Edition, Chapter 3.2, Equation 2.42, assuming 60% combined efficiency of the fan and motor.
5	Based on vendor quoted load of 45kW for equipment included in quote, scaled by ratio of quoted system flow rate (37,000 acfm) to boiler exhaust rate (2,500 acfm)

Table C.6-4: Energy and Environmental Impact Summary for Boiler Nos. 1 – 4 (each)

	Resource Consumption			Energy Equivalents	
Control Technology	Water (MGD)[1]	Gas (Mscf/yr)[1]	Electricity (kWh/yr)[1]	Total Energy Consumed (MMBtu/yr)[2]	Total Energy Consumed (MMBtu/hr)[3]
Wet Scrubber	0.009	0	64,220	219	0.025
Semi-Dry Scrubber	3.49E-07	0	75,170	257	0.029
Dry Scrubber (Injection System)	0	0	72,146	246	0.028
Use of Natural Gas or Propane as a fuel	0	0	0	0	0

	Collateral Emissions					
Control Technology	NO_x (tpy)[4]	GHG (tpy CO_2e)[5]	CO (tpy)[6]	VOC (tpy)[7]	SO_2 (tpy)[8]	Total PM (tpy)[9,10]
Wet Scrubber	0.000	0.000	0.000	0.000	0.000	0.000
Semi-Dry Scrubber	0.000	0.000	0.000	0.000	0.000	0.000
Dry Scrubber (Injection System)	0.000	0.000	0.000	0.000	0.000	0.000
Use of Natural Gas or Propane as a fuel	0.000	0.000	0.000	0.000	0.000	0.000

Notes	
1	Per cost-effectiveness calculation sheets.
2	Total Energy Consumed, MMBtu/yr = (Gas Consumption, Mscf/yr) / (1,000 Mscf/MMscf) * (1,020 MMBtu/MMscf) + (Electricity Consumption, kWh/year) * (3413 Btu-hr/kWh) / (10^6 Btu/MMBtu)
3	Total Energy Consumed, MMBtu/hr = (Total Energy Consumed, MMBtu/yr) / (8,760 hr/yr)
4	Estimated NO_x emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1, NO_x emissions from small uncontrolled boilers. NO_x, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (100 lb NO_x/MMscf) / (2000 lb/ton)
5	Estimated greenhouse gas (GHG) emissions from natural gas combustion in control device calculated using AP-42 emission factors, 5th Edition, Table 1.4-2. Combined GHG Emission Factor, lb CO_2e/MMscf = (120,000 lb CO_2/MMscf) * (CO_2 GWP =1) + (2.2 lb N_2O/MMscf) * (N_2O GWP=310) + (2.3 lb CH_4/MMscf) * (CH_4 GWP=21) GHG Emissions, tpy CO_2e = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (GHG EF=120,730 lb CO_2e/MMscf) / (2000 lb/ton)
6	Estimated CO emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1. CO, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (84 lb CO/MMscf) / (2000 lb/ton)
7	Estimated VOC emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. VOC, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (5.5 lb VOC/MMscf) / (2000 lb/ton)
8	Estimated SO_2 emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. SO_2, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (0.6 lb SO_2/MMscf) / (2000 lb/ton)
9	Estimated PM emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. PM, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (7.6 lb PM/MMscf) / (2000 lb/ton)
10	Total PM includes filterables and condensables. All PM assumed to be <2.5

Table C.7-1: SO_2 BACT Cost Analysis for Wet Scrubbers on Emergency Generator Nos. 1 – 4 (each)

Expense		Scaled Cost	Comments
			Capital Costs
Direct Costs			
	Purchased Equipment Cost (PEC)		
	Scrubber & Accessories	$145,327	Per vendor quote; see Table C.7-1a for details
	Ductwork	$163,663	
	Electrical	$46,587	
	Safety and Security	$5,828	
	Tanks	$48,196	
	Pumps	$55,873	
	Air Compressor/Receiver	$28,037	
	Oxidation System	$23,600	
	Other Equipment	$66,290	
	Feight	$16,147	
	Total Purchased Equipment Cost:	**$599,548**	
	Direct Installation Cost (DIC)		
	Site Preparation	$132,276	Per vendor quote; see Table C.7-1a for details
	Foundations and Supports	$152,612	
	Electrical and Instrumentation	$315,786	
	Piping	$97,371	
	Spare Parts	$30,352	
	Total Direct Installation Costs	**$728,397**	
	Total Direct Costs (TDC):	**$1,327,945**	**TDC=PEC+DIC**
Indirect Costs			
	Engineering	$414,614	Per vendor quote; see Table C.7-1a for details
	Start-Up	$104,087	
	Contractor Fees	$1,873,714	
	Contingency and Taxes	$329,324	
	Total Indirect Costs (TIC):	**$2,721,739**	
Total Capital Costs:		**$4,049,684**	**TCC=TDC+TIC**
			Annual Costs
	Operating Labor @ $30/hr	$938	0.5 hour of Labor per 8-hour shift with 62.5 shifts/year; per EPA Cost Manual Section 5.2, Table 1.4 Labor Cost = shifts * hours/shift * hourly rate
	Maintenance Labor @ $33/hr	$1,031	
	Maintenance Materials	$1,031	100% of Maintenance Labor per EPA Cost Manual Section 5.2, Table 1.4
	Supervisory Labor	$141	15% of Operating Labor; per EPA Cost Manual Section 5.2, Table 1.4
	Electricity	$1,315	MCI Orange project indicated incremental power demand of 145.5 HP, assuming 0.746 kW/HP. Consumption was scaled based on ratio of exhaust flow rates; assumes 8,760 hrs/yr operation. Electricity rate is $0.052/kWh. Electricity Cost = (145.5 HP * 0.746 kW/HP) * 500 hr/yr * $0.056/kWh * (16,103/37,000)
	Caustic	$0.360	Caustic usage of 164.5 tons/year at $297/ton was scaled down based on ratio of SO2 uncontrolled emissions. Adjusted downward from 8,760 hr/year potential operation to 500 hr/year. Caustic Cost = (SO_2 Emissions Reduction, tpy)/57.35 * 164.5 * $297/ton * (500/8,760) hrs/yr
	Water	$6,698	Water usage based on quench evaporation and blowdown requirements as calculated for the NO_x wet scrubber scaled relative to flow rate of calciner; water price is $0.30/kgal
	Insurance and Administrative Expenses	$121,491	3% of TCC per EPA Cost Manual Section 5.2, Table 1.4
	Overhead	$1,884	60% of Labor and utilities as specified in EPA Cost Manual Section 5.2, Table 1.4
	Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
	Capital Recovery Costs	$444,634	Calculated using EPA Cost Manual Section 1, Eqn. 2.8 Capital Recovery Cost = Capital Recovery Factor * TCC
Total Annual Costs:		**$579,163**	
	SO_2 Emissions Reductions (tpy)	0.0074	Based on potential uncontrolled SO_2 emissions of 0.0078 tpy with a control efficiency of 95%
Control Cost ($/ton SO_2 abated)		**$78,159,645**	

Table C.7-1a: SO_2 Detailed Budetary Capital Cost Analysis for Wet Scrubbers on Emergency Generator Nos. 1 – 4 (each)

Per BE&K Engineering estimate on MCI Orange Project for Carbo Ceramics, McIntyre, GA, July, 19, 2010

Unless otherwise noted, scaled costs are scaled from 37,000 acfm to 16,103 acfm using "6/10th rule" (Cost A = Cost B (Flow Rate A/Flow Rate B)$^{0.6}$)

Equipment	Equipment Cost	Notes	Vendor Source
Direct Costs			
Detailed Purchased Equipment Costs (PEC)			
Scrubbers/Scrubber Accessories			
Scrubber	$169,400		Turbosonic
ID Fan	$70,000	Includes fan, motor, and inlet box	Carbo Ceramics
Total Cost of Scrubber:	**$239,400**		
Scaled Cost of Scrubber:	**$145,327**		
Additional Necessary Equipment Not Included In Scrubber Cost			
Ductwork			
Additional Ductwork	$116,700		Warren
Dampers and Expansion Joints	$47,605		Air Techniques
Stack Liner	$105,300		Warren
Total Cost of Ductwork:	**$269,605**		
Scaled Cost of Ductwork:	**$163,663**		
Electrical			
Motor Control Center, Starters and Breaker	$76,744		BE&K
Total Cost of Electrical:	**$76,744**		
Scaled Cost of Electrical:	**$46,587**		
Safety/Security			
Eye Wash and Shower No. 1 and 2	$6,600		Bradley
Entrance Security Camera, Phone, and Card Reader	$3,000		Allowance
Total Cost of Safety/Security:	**$9,600**		
Scaled Cost of Safety/Security:	**$5,828**		
Tanks			
50% Caustic Storage Tank	$43,883	Including insulation	Addison Fabricators
Heat Tracing	$35,511		Delta-Therm
Total Cost of Tanks:	**$79,394**		
Scaled Cost of Tanks:	**$48,196**		
Pumps			
Caustic Pumps	$21,716	Includes motor	GPM Industries
Header and Standby Recycle Pumps	$33,750	4 header pumps, 1 standby recycle pump	Turbo Sonic
Sump Pumps	$26,575	Includes 5 sumps pumps at $5,315 each	Blake & Pendleton
Booster Pump	$5,000	Includes motor	BE&K
Filter	$5,000	For suction line of recycle pumps	
Total Cost of Pumps:	**$92,041**		
Scaled Cost of Pumps:	**$55,873**		
Air Compressor/Receiver			
Air Compressor	$41,396	Includes motor	Blake & Pendleton
Process Air Receiver	$4,789		
Total Cost of Air Compressor/Receiver:	**$46,185**		
Scaled Cost of Air Compressor/Receiver:	**$28,037**		
Oxidation Systems			
Oxidation Tank	$29,700		Turbosonic
Oxidation Tank Blower System			Air Systems Engineering
Oxidation Tank Pump	$9,176	Includes motor	GPM Industries
Total Cost of Oxidation	**$38,876**		
Scaled Cost of Oxidation	**$23,600**		
Other Equipment			
Water Supply System	$20,000	For potable water supply to area	Carbo Ceramics
Scrubber Seal Pot	$6,600		BE&K
Vendor Service	$22,500		-
Miscellaneous	$60,100		-
Total Cost of Other Equipment:	**$109,200**		
Scaled Cost of Other Equipment:	**$66,290**		
Freight			
Freight	$26,600		-
Total Cost of Freight:	**$26,600**		
Scaled Cost of Freight:	**$16,147**		
Total PEC:	**$987,645**		
Scaled PEC:	**$599,548**		

Table C.7-1a: SO_2 Detailed Budetary Capital Cost Analysis for Wet Scrubbers on Emergency Generator Nos. 1 – 4 (each)

Per BE&K Engineering estimate on MCI Orange Project for Carbo Ceramics, McIntyre, GA, July, 19, 2010

Unless otherwise noted, scaled costs are scaled from 37,000 acfm to 16,103 acfm using "6/10th rule" (Cost A = Cost B (Flow Rate A/Flow Rate B)$^{0.6}$)

Equipment	Equipment Cost	Included in Quote
Direct Costs Continued		
Detailed Direct Installation Costs (DIC)		
All DIC Costs are Per BE&K Construction detailed estimate for construction of wet scrubber at CARBO McIntyre facility		
Site Preparation		
Site work, demolition, and earthwork	$217,900	Site preparation, paving and surfacing, underground utilities, erosion control
Total Cost of Site Preparation:	**$217,900**	
Scaled Cost of Site Preparation:	**$132,276**	
Foundations & Supports		
Concrete	$94,300	Insulation, foundation, concrete wall, pier, stair fotting, equipment pads
Structural Steel	$157,100	Steel, grating, handrail, treads
Total Cost of Foundations & Supports:	**$251,400**	
Scaled Cost of Foundations & Supports:	**$152,612**	
Electrical and Instrumentation		
Electrical	$362,300	Feeders, motor control stations, caustic tank electric heat tracing, lighting, receptacles, \baghouse control system wiring, I/O rack communication and power
Instrumentation	$157,900	Field devices, tubing, freight, calibration, control systems
Total Cost of Electrical/Instrumentation:	**$520,200**	
Scaled Cost of Electrical/Instrumentation:	**$315,786**	
Piping		
Process Piping	$160,400	
Total Cost of Piping:	**$160,400**	
Scaled Cost of Piping:	**$97,371**	
Spare Parts		
Capitalized Spares	$50,000	
Total Cost of Spare Parts:	**$50,000**	
Scaled Cost of Spare Parts:	**$30,352**	
Total Direct Installation Cost (DIC):	**$1,199,900**	
Scaled Direct Installation Cost (DIC):	**$728,397**	
Total Direct Cost (TDC):	**$1,327,945**	
Indirect Costs		
All IC Costs are Per BE&K Construction detailed estimate for construction of wet scrubber at nearby CARBO McIntyre facility		
Engineering		
Architectural	$181,900	
Design Engineering	$501,100	
Total Cost of Engineering:	**$683,000**	
Scaled Cost of Engineering:	**$414,614**	
Start-Up		
Start-up	$4,300	
Design Firm Assistance during start-up	$75,165	Not included in BE&K estimate; necessary for the project based on past experience on comparable jobs. Design firm assistance is 15% of design enegineering cost.
Wastewater and Air Pollution Control Consultant Assistance during start-up	$75,000	
Stack Testing	$12,000	
Other Testing	$5,000	
Total Cost of Start-Up:	**$171,465**	
Scaled Cost of Start-Up:	**$104,087**	
Contractor Fees		
Site Preparation Labor	$404,600	
Foundations & Supports Labor	$243,100	
Equipment Labor	$185,600	
Piping Labor	$525,000	
Electrical Labor	$633,100	
Start-Up Labor	$10,500	
Subcontractor Costs	$875,700	
Owner's Cost	$164,000	
Construction Management	$45,000	
Total Cost of Contractor Fees:	**$3,086,600**	
Scaled Cost of Contractor Fees:	**$1,873,714**	
Contingency and Taxes		
Contingency @ 7.7%	$503,900	
Taxes @ 0.6%	$38,600	
Total Cost of Contingency and Taxes:	**$542,500**	
Scaled Cost of Contingency and Taxes:	**$329,324**	
Total Indirect Cost (TIC):	**$2,721,739**	
Grand Total Capital Cost:	**$4,049,684**	

Table C.7-2: SO_2 BACT Cost Analysis for Semi-Dry Scrubber (Spray Dryer Type) on Emergency Generator Nos. 1 – 4 (each)

Expense		Cost	Comments
Capital Costs			
Direct Costs			
	Purchased Equipment Cost (PEC)	$1,300,904	Estimated Capital Cost from a vendor quote for a control system for a boiler with an air flow rate of 37,000 acfm. Estimate includes direct installation costs but does not include freight. Costs were scaled using the "6/10th Rule", and the design flow rate of the Emergency Generators at Millen 16,103 acfm. Cost B = Cost A*(Flow Rate B/Flow Rate A)$^{0.6}$
	Freight	$65,045	Assumed to be 5% of PEC per EPA Cost Manual Section 5.2, Table 1.3
Total Direct Costs:		**$1,365,949**	
Indirect Costs			
	Indirect Installation Costs	$934,854	
Total Indirect Costs:		**$934,854**	
	Contingency	$345,120	15% of direct + indirect costs per Chapter 6 of Plant Design and Economics for Chemical Engineers, Peters and Timmerhaus, 4th Edition
Total Capital Costs		**$2,645,923**	
Annual Costs			
	Operating Labor @ $30/hr	$938	0.5 hour of Labor per 8-hour shift with 62.5 shifts/year; per EPA Cost Manual Section 5.2, Table 1.4 Labor Cost = shifts * hours/shift * hourly rate
	Maintenance Labor @ $33/hr	$1,031	
	Maintenance Materials	$1,031	100% of Maintenance Labor per EPA Cost Manual Section 5.2, Table 1.4
	Supervisory Labor	$141	15% of Operating Labor; per EPA Cost Manual Section 5.2, Table 1.4
	Electricity	$1,539	As estimated from a vendor quote for a similar control system for a boiler with an air flow rate of 37,000 acfm and 127kW operating load
	Lime Reagent	$52	Vendor estimated Lime usage at $134,138 annually with for SO_2 emissions of 80.85 lb/hr. Lime usage was scaled based on ratio of SO_2 uncontrolled emissions. Lime Reagent Cost = $134,138 * (0.992lb/hr / 80.85lb/hr)
	Water	$0.21	Based on lime consumption estimated above and assumption of lime slurry being made up with 10% solids content; water price per Table 1.5-1b.
	Overhead	$1,884	60% of Labor and utilities as specified in EPA Cost Manual Section 5.2, Table 1.4
	Insurance and Administrative	$79,378	3% of TCC per EPA Cost Manual Section 5.2, Table 1.4
	Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
	Capital Recovery Costs (15 year depreciation + 7% interest)	$290,508	Calculated using EPA Cost Manual Section 1, Eqn. 2.8 Capital Recovery Cost = Capital Recovery Factor * TCC
Total Annual Cost		**$376,503**	
	SO_2 Emissions Reductions (Potential Emissions, tpy)	0.0062	Based on 80% Control efficiency and 0.0078 tpy uncontrolled SO_2 emissions
Control Costs ($/ton abated)		**$60,336,960**	

Table C.7-3: SO_2 BACT Cost Analysis for Injection Based Dry Scrubbers on Emergency Generator Nos. 1 – 4 (each)

Expense		Cost	Comments
Capital Costs			
Direct Costs			
	Purchased Equipment Cost (PEC)		
	Purchased Equipment Cost (PEC)	$1,078,846	See Table C.7-3a
	Total PEC	**$1,078,846**	
	Direct Installation Cost (DIC)		
	Foundations and Support	$78,916	See Table C.7-3a
	Other Equipment	$131,122	
	Piping	$3,035	
	Ductwork	$12,141	
	Controls Integration	$18,211	
	Electrical	$15,176	
	Total DIC:	**$258,602**	
	Total Direct Cost:	**$1,337,448**	
Indirect Costs			
	Start-Up Preparation	$12,141	See Table C.7-3a
	Engineering	$30,352	
	Contractor Fees	$63,740	
	Total Indirect Cost	**$106,233**	
	Contingency	$216,552	See Table C.7-3a
	Lost Production	$525,000	
Total Capital Costs		**$2,185,234**	
Annual Costs			
	Operating Labor @ $30/hr	$938	0.5 hour of Labor per 8-hour shift with 62.5 shifts/year; per EPA Cost Manual Section 5.2, Table 1.4
	Maintenance Labor @ $33/hr	$1,031	Labor Cost = shifts * hours/shift * hourly rate
	Maintenance Materials	$1,031	100% of Maintenance Labor per EPA Cost Manual Section 5.2, Table 1.4
	Supervisory Labor	$141	15% of Operating Labor; per EPA Cost Manual Section 5.2, Table 1.4
	Electricity	$1,091	See Table C.7-3b
	Lime Reagent	$120	Vendor estimated Lime usage at $308,869 annually for SO_2 emissions of 80.85 lb/hr. Lime usage was scaled based on ratio of uncontrolled SO_2 emissions. Lime Reagent Cost = $308,869 * (0.992lb/hr / 80.85lb/hr)
	Overhead	$1,884	60% of Labor and utilities as specified in EPA Cost Manual Section 5.2, Table 1.4
	Insurance and Administrative Expenses	$65,557	3% of TCC per EPA Cost Manual Section 5.2, Table 1.4
	Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
	Capital Recovery Costs (15 year depreciation + 7% interest)	$239,927	Calculated using EPA Cost Manual Section 1, Eqn. 2.8 Capital Recovery Cost = Capital Recovery Factor * TCC
Total Annual Costs		**$311,720**	
	SO_2 Emission Reductions (tpy)	0.0039	Based on potential uncontrolled SO_2 emission rate 0.0078 tpy with a control efficiency of 50%
Control Costs($/ton SO_2 abated)		**$79,928,174**	

Table C.7-3a: Detailed Cost Analysis for Injection Based Dry Scrubbers on Emergency Generator Nos. 1 – 4 (each)

Estimated by TMTS Associates based on a 2009 quote from Fuel Tech High Inc. for Dry Lime Injection.
Unless otherwise noted, scaled costs are scaled from 37,000 acfm to 16,103 acfm using "6/10th rule" (Cost A = Cost B (Flow Rate A/Flow Rate B)

Equipment	Budgetary Cost	Notes	Source
Direct Costs			
Purchased Equipment Costs (PEC)			
Purchased Equipment Costs (PEC)			
Injection Based Dry Scrubber	$1,777,200	Estimated Capital Cost from a vendor quote for a control system for a boiler with an airflow rate of 37,000 acfm.	Fuel Tech
Total PEC:	**$1,777,200**		
Scaled PEC:	**$1,078,846**		
PEC:	**$1,078,846**		
Direct Installation Costs (DIC)			
Foundations and Support			
Foundations/ roadways	$50,000	Assumes use of slab-not pilings	Estimated by CARBO project engineering
Structural Steel	$80,000	Belt support, dust collector support, duct, pipe supports, Waste Hopper cover	Estimated by CARBO project engineering
Total Cost of Foundations/Support:	**$130,000**		
Scaled Cost of Foundations/Support:	**$78,916**		
Other Equipment			
Nuisance Dust Collector	$36,000		Comparable Experience on other jobs
Broken Bag detectors (2)	$9,000		Recent quote
Nuisance collector stack	$15,000		Estimated by CARBO project engineering
Belt Conveyor	$80,000	Air supported belt conveyor 24"x 66', 3 hp	Based on comparable Experience on other jobs - costing developed by CARBO project engineering
Spare Parts	$40,000		
Waste Hoppers	$36,000	20 yard capacity with cover and teflon liner, quantity of 3 @ $12,000 ea.	Estimated by CARBO project engineering
Total Cost of Other Equipment:	**$216,000**		
Scaled Cost of Other Equipment:	**$131,122**		
Piping			
Piping	$5,000	Air	Estimated by CARBO project engineering
Total Cost of Piping:	**$5,000**		
Scaled Cost of Piping:	**$3,035**		
Ductwork			
Ductwork	$20,000	For Nuisance Dust	Estimated by CARBO project engineering
Total Cost of Ductwork:	**$20,000**		
Scaled Cost of Ductwork:	**$12,141**		
Controls Integration			
Controls Integration	$30,000	Includes HMI/Graphics development, logic programming for extra items outside of vendor scope	
Total Cost of Controls Integration:	**$30,000**		
Scaled Cost of Controls Integration:	**$18,211**		
Electrical			
4 motors, 6 devices	$20,000		Estimated by CARBO project engineering
Yard and Local Lighting	$5,000	Includes 2 pole mounted HPS at 40' high and 2 LPS area lights	Estimated by CARBO project engineering
Total Cost of Electrical:	**$25,000**		
Scaled Cost of Electrical:	**$15,176**		
Total DIC:	**$258,602**		
Total Direct Cost:	**$1,337,448**		

Table C.7-3a: Detailed Cost Analysis for Injection Based Dry Scrubbers on Emergency Generator Nos. 1 – 4 (each)

Estimated by TMTS Associates based on a 2009 quote from Fuel Tech High Inc. for Dry Lime Injection.
Unless otherwise noted, scaled costs are scaled from 37,000 acfm to 16,103 acfm using "6/10th rule" (Cost A = Cost B (Flow Rate A/Flow Rate B)

Equipment	Budgetary Cost	Notes	Source
Indirect Costs			
Start-Up Preparation			
Stack Testing	$20,000		
Total Cost of Start-Up Preparation:	**$20,000**		
Scaled Cost of Start-Up Preparation:	**$12,141**		
Engineering			
Detailed Design and Engineering Review of Detailed Design	$50,000		
Total Cost of Engineering:	**$50,000**		
Scaled Cost of Engineering:	**$30,352**		
Contractor Fees			
Project Management for 4 months	$80,000		
Labor for Setting/Installation	$25,000	For nuisance collector, conveyor etc	Estimated by CARBO project engineering
Total Cost of Contractor Fees:	**$105,000**		
Scaled Cost of Contractor Fees:	**$63,740**		
Total Indirect Cost:	**$106,233**		
Contingency @ 15%	$216,552	15% of direct + indirect costs	Chapter 6 of Plant Design and Economics for Chemical Engineers, Peters and Timmerhaus, 4th Edition
Cost of Lost Production	$525,000		
Grand Total Capital Cost:	**$2,185,234**		

Table C.7-3b: SO_2 BACT Energy Cost Analysis for Injection Based Dry Scrubber on Emergency Generator Nos. 1 – 4 (each)

Gas flowrate:	16,103	[acfm]
Reference temperature:	77	[°F]
Inlet gas temperature (after baghouse):	869	[°F]
Gas flowrate:	6,504	[scfm]

	Average Unit Cost[1]	Energy Required	No. Hours per Year[2]		
Direct System Load[3]	0.056 $/kWh	20 kW	1,000	$	1,090.87
Total Annual Electricity Usage:	19,585 kWh/yr			$	1,090.87

Footnotes	
1	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
2	Direct system load includes freeze protection and related heaters for operational readiness in cold weather and so is assumed 1,000 hours per year.
3	Based on vendor quoted load of 45kW for equipment included in quote, scaled by ratio of quoted system flow rate (37,000 acfm) to generator exhaust rate (16,103 acfm)

Table C.7-4: Energy and Environmental Impact Summary for Emergency Generator Nos. 1 – 4 (each)

Control Technology	Resource Consumption: Water (MGD)[1]	Resource Consumption: Diesel Fuel (Mgal/yr)[1]	Resource Consumption: Electricity (kWh/yr)[1]	Energy Equivalents: Total Energy Consumed (MMBtu/yr)[2]	Energy Equivalents: Total Energy Consumed (MMBtu/hr)[3]
Wet Scrubber	0.061	0	23,610	80.6	0.161
Semi-Dry Scrubber	1.92E-06	0	27,636	94.3	0.189
Dry Scrubber (Injection System)	0	0	19,585	66.8	0.134
Use of Natural Gas or Propane as a fuel	0	0	0	0	0

Control Technology	Collateral Emissions: NO_x (tpy)[4]	GHG (tpy CO_2e)[5]	CO (tpy)[6]	VOC (tpy)[7]	SO_2 (tpy)[8]	Total PM (tpy)[9,10]
Wet Scrubber	0.000	0.000	0.000	0.000	0.000	0.000
Semi-Dry Scrubber	0.000	0.000	0.000	0.000	0.000	0.000
Dry Scrubber (Injection System)	0.000	0.000	0.000	0.000	0.000	0.000
Use of Natural Gas or Propane as a fuel	0.000	0.000	0.000	0.000	0.000	0.000

Notes	
1	Per cost-effectiveness calculation sheets.
2	Total Energy Consumed, MMBtu/yr = (Gas Consumption, Mscf/yr) / (1,000 Mscf/MMscf) * (1,020 MMBtu/MMscf + (Diesel Fuel Consumption, gal/year) * (137,000 Btu/gal) / (10^6 Btu/MMBtu
3	Total Energy Consumed, MMBtu/hr = (Total Energy Consumed, MMBtu/yr) / (500 hr/yr
4	Estimated NO_x emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-1, NO_x emissions from small uncontrolled boilers. NO_x tpy = (Gas Consumption, gal) * (1 Kgal/1000 gal) * (20 lb NO_x/Kgal) / (2000 lb/ton)
5	Estimated greenhouse gas (GHG) emissions from diesel combustion in control device calculated using AP-42 emission factors, 5th Edition, Tables 1.3-8 and 1.3-12. Combined GHG Emission Factor, lb CO_2e/kgal = (22,300 lb CO_2/kgal) * (CO_2 GWP =1) + (0.260 lb N_2O/kgal) * (N_2O GWP=310) + (2.3 lb CH_4/MMscf) * (CH_4 GWP=21) GHG Emissions, tpy CO_2e = (Gas Consumption, gal) * (1 kgal/1000 gal) * (GHG EF=22,382 lb CO_2e/kgal) / (2000 lb/ton)
6	Estimated CO emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-1. CO, tpy = (Gas Consumption, gal) * (1 kgal/1000 gal) * (5 lb CO/kgal) / (2000 lb/ton)
7	Estimated VOC emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-3. VOC, tpy = (Gas Consumption, gal) * (1 kgal/1000 gal) * (0.200 lb VOC/kgal) / (2000 lb/ton)
8	Estimated SO_2 emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-1. SO_2, tpy = (Gas Consumption, gal) * (1 kgal/1000 gal) * (142S lb SO_2/kgal) / (2000 lb/ton); S=sulfur content = 0.0015%
9	Estimated PM emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-1 and 1.3-2. PM, tpy = (Gas Consumption, gal) * (1 kgal/1000 gal) * (3.3 lb PM/kgal) / (2000 lb/ton) Total PM E.F. = 3.3 (Filterable E.F=2.0 lb/kgal and condensable E.F.=1.3 lb/kgal)
10	Total PM includes filterables and condensables. All PM assumed to be <2.5 microns

ATTACHMENT D

Detailed PM BACT Analysis

VOLUME II, ATTACHMENT D
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D. Top-Down BACT Analysis: Particulate Matter ($PM/PM_{10}/PM_{2.5}$)

D.1 PM Review: Direct Fired Rotary Calciner Nos. 1 – 4

Particulate Matter (PM) emissions are generated from the calcining of kaolin ore and consist primarily of fine to medium clay particles. Control technologies, such as a high efficiency baghouse, an electrostatic precipitator (ESP) and a wet scrubber, were evaluated for control of PM emissions from Direct-fired Rotary Calciner Nos. 1 – 4.

All limits proposed are for direct $PM/PM_{10}/PM_{2.5}$, which is the total of filterable and condensable fractions. The grain loading limits have been determined based primarily on dispersion modeling impact analyses.

Step 1: Identify all control technologies

In reviewing the BACT alternatives to control emissions of PM from the direct-fired rotary calciner, applicable BACT determinations and permits for non-metallic mineral processing kilns and calciners have been reviewed, as summarized in Table D.1-1 below.

Table D.1-1: Summary of PM Control Technology Determinations for Kilns and Calciners

Facility Name	Location	Agency	Database	Permit Date	Process Type[1]	Process Description	Controls / Type	Emission Limits/ Description
GCC Dacotah	Rapid City, SD	SD DENR	RBLC	Apr-03	90.028	Coal-Fired Rotary Kiln	Fabric Filter	0.010 gr/dscf 11.95 lb/hr 0.13 lb/ton
Eagle-Picher Filtration & Minerals, Inc.	Vale, OR	OR DEQ	RBLC	May-03	90.024	Natural Gas-Fired Calciner	Pulse-Jet Baghouse	0.100 gr/dscf
Lehigh Cement Company	Mason City, IA	IA DNR	RBLC	Dec-03	90.028	Coal-Fired Kiln/Calciner/ Preheater	Electrostatic Precipitator	0.516 lb/ton
Big River Industries, Inc	Baton Rouge, LA	LA DEQ	RBLC	June-06	90.024	Coal-Fired Rotary Kilns (4)	Venturi Scrubber	0.9700 lb/hr 4.23 tpy
KaMin, LLC	Macon, GA	GA EPD	Title V permit	Oct-08	90.024	Natural Gas-fired Calciner	Baghouse	0.015 gr/dscf
Arizona Portland Cement Co.	Pheonix, AZ	AZ DEQ	RBLC	Dec-08	90.028	Coal-Fired Kiln	Baghouse	0.008 g/dscf
CARBO – Toomsboro	Toomsboro, GA	GA EPD	Title V permit	Dec-09	90.017	Natural gas-fired Rotary Calciners	Baghouse	0.01 gr/dscf
CARBO – McIntyre	McIntyre, GA	GA EPD	Title V permit	Dec-09	90.017	Natural gas-fired Rotary Calciners	Baghouse	0.01 gr/dscf

[1] 90.017 = Calciners & Dryers and Mineral processing Facilities, 90.024 = Nonmetallic Mineral Processing (excludes 90.017), 90.028 = Portland cement Manufacturing; All Process types beginning with 90 are Mineral Products

As a consequence of our review, a high efficiency baghouse, an electrostatic precipitator (ESP), and a wet scrubber are being considered as potential control options as noted in Table D.1-2 below.

Table D.1-2: Evaluated Control Options for PM Emissions – Direct-fired Rotary Calciners

Option No.	Control Technology
1	High Efficiency Baghouse
2	Electrostatic Precipitator
3	Wet Scrubber

Option 1 – High Efficiency Baghouse

Baghouses have been used extensively during the last twenty-five years in the non-metallic mineral industry. They operate based on the principle that particles and flue gas are separated in tube-shaped filter bags arranged in parallel flow paths. The particulates are collected either on the outside (dirty gas flow from outside-to-inside) or the inside (dirty gas flow from inside-to-outside) of the bag. The main differences among the various types of fabric filter technologies are related to the type of bag cleaning method, including reverse-gas, shake-deflate, pulse-jet, and sonic cleaning. Of the four methods, the pulse-jet baghouse is generally used more often in the non-metallic mineral industry as it is smaller and usually more cost effective due to requiring less bag surface area for a given air flow rate.

Pulse-jet cleaning uses compressed air to force air through the bag and expand it. Once the fabric reaches its extension limit, dust separates from the bag and is carried away from the fabric surface by air escaping through the bag. This highly efficient system is able to achieve removal/control efficiencies as high as 99.9%.[1]

Option 2 - Electrostatic Precipitator (ESP)

Electrostatic precipitators (ESPs) are particle control devices that remove particles from flowing gas streams onto collector plates through the use of electrical forces. Typically, new ESPs can achieve design removal efficiencies for PM of up to above 99%[2]. While several factors determine ESP collection efficiency, the size of the ESP is most important as size determines treatment time; the longer a particle spends in the ESP, the greater its chance of being collected. Collection efficiency is also affected by dust resistivity, gas temperature, gas turbulence, chemical composition (of the dust and the gas), particle size distribution, and electric field strength.

ESPs typically have high capital, maintenance, and energy costs associated with their operation. In general, they are not well suited for use in processes that are highly variable as they are very sensitive to fluctuations in gas stream conditions (flow rates, temperatures, particulate and gas composition, and particulate loadings). ESPs are also difficult to install in sites that have limited space as they must be relatively large to obtain

[1] Discussion on high efficiency baghouse from US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.1, Subsections 1.1 and 1.2.3.
[2] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.1 Subsection 3.2.1.2 Table 3.8

the low gas velocities necessary for efficient PM collection. Certain particulates are difficult to collect due to extremely high or low resistivity characteristics. [3]

Option 3 – Wet Scrubber System

Wet scrubbers are primarily used to control PM through the impaction, diffusion, interception and/or absorption of PM particles onto droplets of liquid. Collection efficiencies vary based on particle size distribution of the waste gas stream and scrubber type, and range anywhere from 40-99%.[4]

Although wet scrubbers are more compact than baghouses or ESPs, they are associated with high pressure drops across the control system, and are limited to lower waste gas flow rates and temperatures. Additionally, they generate solid waste in the form of sludge which requires treatment and/or disposal. Wastewater is also generated when the particles come into contact with droplets of liquid. The moisture added to the gas stream can also lead to downstream corrosion and visibility problems, and is a consumptive use of limited water resources.[4]

Step 2: Eliminate technically infeasible options

All of the above control technologies are technically feasible for purposes of this BACT determination.

Step 3: Rank remaining technologies by control effectiveness

Table D.1-3: Ranking of Control Technology – Direct-fired Rotary Calciners

Control Technology Ranking	Option No.	Control Technology	Control Efficiency
1 (tie)	1	High Efficiency Baghouse	99% +
1 (tie)	2	Electrostatic Precipitator	99% +
1 (tie)	3	Wet Scrubber	99% +

Step 4: Evaluate most effective controls and document results

Option 2 - Electrostatic Precipitator (ESP)

An ESP, although technically feasible for application to Direct-fired Rotary Calciner Nos. 1 – 4, is no more effective in controlling PM than a baghouse (Option 1). Since baghouses have been successfully demonstrated in practice to control PM emissions in similar situations and at other CARBO plants, it is the preferred control option. ESPs will not be given any further consideration as BACT for PM emissions from the direct-fired rotary calciners.

[3] Discussion on ESPs from US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.3, Subsections 3.1.1 and 3.1.4.

[4] Discussion on wet scrubber systems from US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.2, Subsections 2.1 and 2.2.

Option 3 – Wet Scrubber System

A wet scrubber, although technically feasible for application to a direct-fired rotary calciner, will be no more effective in controlling PM than a baghouse (Option 1). Since baghouses have been successfully demonstrated in practice to control PM emissions in similar situations and at other CARBO plants, it is the preferred control option. Wet scrubbers will not be given any further consideration as BACT for PM emissions from Direct-fired Rotary Calciner Nos. 1 – 4.

Step 5: Select BACT

Option 1 – High Efficiency Baghouse

A high efficiency baghouse with a PM/PM_{10} and $PM_{2.5}$ emissions limitation of 0.01 gr/dscf for each calciner is proposed as BACT for the four direct-fired rotary calciners (Emission Unit ID Nos. KLN1 – KLN4) as summarized below.

Table D.1-4: PM BACT Proposed for Direct-fired Rotary Calciner Nos. 1 – 4

Emission Unit ID Nos.	BACT Limit
KLN1 – KLN4	The use of a high efficiency baghouse to control PM/PM_{10} from each direct-fired rotary calciner limited to 0.01 gr/dscf.
	The use of a high efficiency baghouse to control $PM_{2.5}$ from each direct-fired rotary calciner limited to 0.01 gr/dscf.

D.2 PM Review: Spray Dryer Nos. 1 – 8

Particulate matter emissions from the dryers consist primarily of fine to medium clay particles. Control technologies such as a high efficiency baghouse, an electrostatic precipitator (ESP), and a wet scrubber were evaluated to control PM emissions from Spray Dryer Nos. 1 – 8.

All limits proposed are for direct $PM/PM_{10}/PM_{2.5}$, which is the total of filterable and condensable fractions. The grain loading limits have been determined based on exclusive dispersion modeling impact analyses.

Step 1: Identify all control technologies

In reviewing the BACT alternatives to control emissions of PM from the eight spray dryers, applicable BACT determinations and permits for non-metallic mineral processing spray dryers have been reviewed, as summarized in Table D.2-1 below:

Table D.2-1: Summary of PM Control Technology Determinations for Spray Dryers

Facility Name	Location	Agency	Database	Process Type[1]	Permit Date	Process Description	Controls / Type	Emission Limits/Description
Eagle-Picher Filtration & Minerals, Inc.	Vale, OR	OR DEQ	RBLC	90.024	May-03	Natural Gas-Fired Dryer	Pulse-Jet Baghouse	0.100 gr/dscf
Dalitalia LLC	Muskogee, OK	OK DEQ	RBLC	90.017	Oct-05	Spray Dryers	Baghouse	0.018 gr/dscf
KaMin, LLC	Macon, GA	GA EPD	Title V permit	90.024	Oct-08	Natural Gas-Fired Spray Dryers	Baghouse	0.02 gr/dscf
CARBO – Toomsboro	Toomsboro, GA	GA EPD	Title V permit	90.024	Dec-09	Natural Gas-fired Spray Dryers	Baghouse	0.02 gr/dscf
CARBO – McIntyre	McIntyre, GA	GA EPD	Title V permit	90.024	Dec-09	Natural Gas-fired Spray Dryers	Baghouse	0.02 gr/dscf

[1] 90.017 = Calciners & Dryers and Mineral Processing Facilities, 90.024 = Nonmetallic Mineral Processing (excludes 90.017)

As a consequence of our review, a high efficiency baghouse, an electrostatic precipitator (ESP) and a wet scrubber are being considered as noted in Table D.2-2 below.

Table D.2-2: Evaluated Control Options for PM Emissions – Spray Dryers

Option No.	Control Technology
1	High Efficiency Baghouse
2	Electrostatic Precipitator
3	Wet Scrubber

Option 1 – High Efficiency Baghouse

Baghouses have been used extensively during the last twenty-five years in the non-metallic mineral industry. They operate based on the principle that particles and flue gas are separated in tube-shaped filter bags arranged in parallel flow paths. The particulates are collected either on the outside (dirty gas flow from outside-to-inside) or the inside (dirty gas flow from inside-to-outside) of the bag. The main differences among the various types of fabric filter technologies are related to the type of bag cleaning method, including reverse-gas, shake-deflate, pulse-jet, and sonic cleaning. Of the four, the pulse-jet baghouse is generally used more often in the non-metallic mineral industry as it is smaller and usually more cost effective due to requiring less bag surface area for a given air flow rate.

Pulse-jet cleaning uses compressed air to force air through the bag and expand it. Once the fabric reaches its extension limit, dust separates from the bag and is carried away from the fabric surface by air escaping through the bag. This highly efficient system is able to achieve removal/control efficiencies as high as 99.9%.[5]

Option 2 - Electrostatic Precipitator (ESP)

Electrostatic precipitators (ESPs) are particle control devices that remove particles from flowing gas streams onto collector plates through the use of electrical forces. Typically, new ESPs can achieve design removal efficiencies for PM of up to above 99%[6]. While several factors determine ESP collection efficiency, the size of the ESP is most important as size determines treatment time; the longer a particle spends in the ESP, the greater its chance of being collected. Collection efficiency is also affected by dust resistivity, gas temperature, gas turbulence, chemical composition (of the dust and the gas), particle size distribution, and electric field strength.

ESPs typically have high capital, maintenance, and energy costs associated with their operation. In general, they are not well suited for use in processes that are highly variable as they are very sensitive to fluctuations in gas stream conditions (flow rates, temperatures, particulate and gas composition, and particulate loadings). ESPs are also difficult to install in sites that have limited space as they must be relatively large to obtain the low gas velocities necessary for efficient PM collection. Certain particulates are difficult to collect due to extremely high or low resistivity characteristics. [7]

Option 3 – Wet Scrubber System

Wet scrubbers are primarily used to control PM through the impaction, diffusion, interception and/or absorption of PM particles onto droplets of liquid. Collection efficiencies vary based on particle size distribution of the waste gas stream and scrubber type, and range anywhere from 40-99%[8].

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[5] Discussion on high efficiency baghouse from US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.1, Subsections 1.1 and 1.2.3.

[6] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.3 Subsection 3.2.1.2 Table 3.8

[7] Discussion on ESPs from US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.3, Subsections 3.1.1 and 3.1.4.

[8] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.2 Subsection 2.1

Although wet scrubbers are more compact than baghouses or ESPs, they are associated with high pressure drops across the control system, and are limited to lower waste gas flow rates and temperatures. Additionally, they generate solid waste in the form of sludge which requires treatment and/or disposal. Wastewater is also produced when the particles come into contact with droplets of liquid. The moisture added to the gas stream can also lead to downstream corrosion and visibility problems, and is a consumptive use of limited water resources.[9]

Step 2: Eliminate technically infeasible options

All of the above control technologies are technically feasible for purposes of this BACT determination.

Step 3: Rank remaining technologies by control effectiveness

Table D.2-3: Ranking of Control Technology – Spray Dryers

Control Technology Ranking	Option No.	Control Technology	Control Efficiency
1 (tie)	1	High Efficiency Baghouse	99% +
1 (tie)	2	Electrostatic Precipitator	99% +
1 (tie)	3	Wet Scrubber	99% +

Step 4: Evaluate most effective controls and document results

Option 2 - Electrostatic Precipitator (ESP)

Based on our review of known existing non-metallic mineral sources in Georgia as well as our review of all sources identified in the RACT/BACT/LAER database (as provided in Table D.2-1), there is no indication that ESPs have ever been utilized for controlling PM emissions from dryer operations similar to those subject to this review. An ESP, although technically feasible for application to a spray dryer, will be no more effective in controlling PM than a high efficiency baghouse (Option 1). Since baghouses have been extensively used to control PM emissions successfully in similar situations and other CARBO plants, it is the preferred control option. ESPs will not be given any further consideration as BACT for PM emissions from the spray dryers.

Option 3 – Wet Scrubber System

A wet scrubber, although technically feasible for application to a spray dryer, will be no more effective in controlling PM than a baghouse (Option 1). Since baghouses have been successfully demonstrated in practice to control PM emissions in similar situations and at other CARBO plants, it is the preferred control option. Wet scrubbers will not be given any further consideration as BACT for PM emissions from the spray dryers.

[9] Discussion on wet scrubber systems from US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.2, Subsections 2.1 and 2.2.

Step 5: Select BACT

Option 1 – High Efficiency Baghouse

A high efficiency baghouse with a PM/PM_{10} and $PM_{2.5}$ emissions limitation of 0.02 gr/dscf and 0.0075 gr/dscf respectively for each spray dryer is proposed as BACT as summarized below.

Table D.2-4: PM BACT Proposed for Spray Dryer Nos. 1 – 8

Emission Unit ID Nos.	BACT Limit
SD01 – SD08	The use of a high efficiency baghouse to control PM/PM_{10} emissions from each spray dryer limited to 0.02 gr/dscf.
	The use of a high efficiency baghouse to control $PM_{2.5}$ emissions from each spray dryer limited to 0.0075 gr/dscf.

D.3 PM Review: New Material Storage and Handling Systems

This section covers the proposed material storage and handling emission units as listed in Table D.3-1 below.

All proposed limits are for direct $PM/PM_{10}/PM_{2.5}$, which is the combination of filterable and condensable fractions. The grain loading limits have been determined based on exclusive dispersion modeling impact analyses.

Table D.3-1: Material Storage and Handling Emissions Units

Emission Unit ID No.	Emission Unit Description	Emission Unit Group ID Nos.
DSB1	Spray Dryer No. 1 Feed Bin	GP01
DUB1	Spray Dryer No. 1 Unders Bin	
DSB2	Spray Dryer No. 2 Feed Bin	
DUB2	Spray Dryer No. 2 Unders Bin	
OC01	Overflow Conveyor No. 1	
ABC1	Accepts Belt Conveyor No. 1	
GPC1	Pellet Collection Conveyor No. 1	
GPT1	Pellet Transfer Conveyor No. 1	
GPE1	Pellet Bucket Elevator No. 1	
GSH1	Screen Surge Hopper No. 1	
GSC1	Pellet Screen No. 1-1	
GSC2	Pellet Screen No. 1-2	
GSC3	Pellet Screen No. 1-3	
OBC1	Oversize Collection Belt Conveyor No. 1	
ORB1	Oversize Surge Bin No. 1	
UBC1	Unders Collection Belt Conveyor No. 1	
URC1	Unders Reversible Belt Conveyor No. 1	
KFE1	Calciner No. 1 Feed Bin Bucket Elevator	
KFB1	Calciner No. 1 Feed Bin	
KRB1	Calciner No. 1 Recycle Feed Bin	
KRE1	Calciner No. 1 Recycle Feed Bin Bucket Elevator	
KFC1	Calciner No. 1 Feed Conveyor	
KCE1	Calciner No. 1 Cooler Bucket Elevator	KAE1
KPS1	Calciner No. 1 Product Screen	
KFS1	Calciner No. 1 Fines Screen	
KQC1	Calciner No. 1 Product QC Bin A	
KQC2	Calciner No. 1 Product QC Bin B	
KQC3	Calciner No. 1 Product QC Bin C	
KQC4	Calciner No. 1 Product QC Bin D	
KCS1	Calciner No. 1 Product Screen DPCS	
KCS2	Calciner No. 1 Fines Screen DPCS	
RRL1	Railcar Loading Operations No. 1	----
BS01	Bulk Product Silo No. 1-1	
BS02	Bulk Product Silo No. 1-2	
BS03	Bulk Product Silo No. 1-3	
BS04	Bulk Product Silo No. 1-4	
DSB3	Spray Dryer No. 3 Feed Bin	GP02
DUB3	Spray Dryer No. 3 Unders Bin	
DSB4	Spray Dryer No. 4 Feed Bin	
DUB4	Spray Dryer No. 4 Unders Bin	
OC02	Overflow Conveyor No. 2	
ABC2	Accepts Belt Conveyor No.2	
GPC2	Pellet Collection Conveyor No. 2	
GPT2	Pellet Transfer Conveyor No. 2	
GPE2	Pellet Bucket Elevator No. 2	
GSH2	Screen Surge Hopper No. 2	

Table D.3-1: Material Storage and Handling Emissions Units

Emission Unit ID No.	Emission Unit Description	Emission Unit Group ID Nos.
GSC4	Pellet Screen No. 2-1	
GSC5	Pellet Screen No. 2-2	
GSC6	Pellet Screen No. 2-3	
OBC2	Oversize Collection Belt Conveyor No. 2	
ORB2	Oversize Surge Bin No. 2	
UBC2	Unders Collection Belt Conveyor No. 2	
URC2	Unders Reversible Belt Conveyor No. 2	
KFE2	Calciner No. 2 Feed Bin Bucket Elevator	
KFB2	Calciner No. 2 Feed Bin	
KRB2	Calciner No. 2 Recycle Feed Bin	
KRE2	Calciner No. 2 Recycle Feed Bin Bucket Elevator	
KFC2	Calciner No. 2 Feed Conveyor	
KCE2	Calciner No. 2 Cooler Bucket Elevator	KAE2
KPS2	Calciner No. 2 Product Screen	
KFS2	Calciner No. 2 Fines Screen	
KQC5	Calciner No. 2 Product QC Bin A	
KQC6	Calciner No. 2 Product QC Bin B	
KQC7	Calciner No. 2 Product QC Bin C	
KQC8	Calciner No. 2 Product QC Bin D	
KCS3	Calciner No. 2 Product Screen DPCS	
KCS4	Calciner No. 2 Fines Screen DPCS	
BS05	Bulk Product Silo No. 2-1	----
BS06	Bulk Product Silo No. 2-2	
BS07	Bulk Product Silo No. 2-3	
BS08	Bulk Product Silo No. 2-4	
DSB5	Spray Dryer No. 5 Feed Bin	GP03
DUB5	Spray Dryer No. 5 Unders Bin	
DSB6	Spray Dryer No. 6 Feed Bin	
DUB6	Spray Dryer No. 6 Unders Bin	
OC03	Overflow Conveyor No. 3	
ABC3	Accepts Belt Conveyor No. 3	
GPC3	Pellet Collection Conveyor No. 3	
GPT3	Pellet Transfer Conveyor No. 3	
GPE3	Pellet Bucket Elevator No. 3	
GSH3	Screen Surge Hopper No. 3	
GSC7	Pellet Screen No. 3-1	
GSC8	Pellet Screen No. 3-2	
GSC9	Pellet Screen No. 3-3	
OBC3	Oversize Collection Belt Conveyor No. 3	
ORB3	Oversize Surge Bin No. 3	
UBC3	Unders Collection Belt Conveyor No. 3	
URC3	Unders Reversible Belt Conveyor No. 3	
KFE3	Calciner No. 3 Feed Bin Bucket Elevator	
KFB3	Calciner No. 3 Feed Bin	
KRB3	Calciner No. 3 Recycle Feed Bin	
KRE3	Calciner No. 3 Recycle Feed Bin Bucket Elevator	
KFC3	Calciner No. 3 Feed Conveyor	
KCE3	Calciner No. 3 Cooler Bucket Elevator	KAE3
KPS3	Calciner No. 3 Product Screen	
KFS3	Calciner No. 3 Fine Screen	
KQC9	Calciner No. 3 Product QC Bin A	
KQ10	Calciner No. 3 Product QC Bin B	
KQ11	Calciner No. 3 Product QC Bin C	
KQ12	Calciner No. 3 Product QC Bin D	
KCS5	Calciner No. 3 Product Screen DPCS	
KCS6	Calciner No. 3 Fines Screen DPCS	
PBC3	Calciner No. 3 Product Screen Belt Conveyor	----
PBE3	Calciner No. 3 Product Screen Bucket Elevator	
FBC3	Calciner No. 3 Fines Screen Belt Conveyor	

Table D.3-1: Material Storage and Handling Emissions Units

Emission Unit ID No.	Emission Unit Description	Emission Unit Group ID Nos.
FBE3	Calciner No. 3 Fines Screen Bucket Elevator	
RRL2	Railcar Loading Operations No. 2	
BS09	Bulk Product Silo No. 3-1	
BS10	Bulk Product Silo No. 3-2	
BS11	Bulk Product Silo No. 3-3	
BS12	Bulk Product Silo No. 3-4	
DSB7	Spray Dryer No. 7 Feed Bin	GP04
DUB7	Spray Dryer No. 7 Unders Bin	
DSB8	Spray Dryer No. 8 Feed Bin	
DUB8	Spray Dryer No. 8 Unders Bin	
OC04	Overflow Conveyor No. 4	
ABC4	Accepts Belt Conveyor No.4	
GPC4	Pellet Collection Conveyor No. 4	
GPT4	Pellet Transfer Conveyor No. 4	
GPE4	Pellet Bucket Elevator No. 4	
GSH4	Screen Surge Hopper No. 4	
GS10	Pellet Screen No. 4-1	
GS11	Pellet Screen No. 4-2	
GS12	Pellet Screen No. 4-3	
OBC4	Oversize Collection Belt Conveyor No. 4	
ORB4	Oversize Surge Bin No. 4	
UBC4	Unders Collection Belt Conveyor No. 4	
URC4	Unders Reversible Belt Conveyor No. 4	
KFE4	Calciner No. 4 Feed Bin Bucket Elevator	
KFB4	Calciner No. 4 Feed Bin	
KRB4	Calciner No. 4 Recycle Feed Bin	
KRE4	Calciner No. 4 Recycle Feed Bin Bucket Elevator	
KFC4	Calciner No. 4 Feed Conveyor	
KCE4	Calciner No. 4 Cooler Bucket Elevator	KAE4
KPS4	Calciner No. 4 Product Screen	
KFS4	Calciner No. 4 Fine Screen	
KQ13	Calciner No. 4 Product QC Bin A	
KQ14	Calciner No. 4 Product QC Bin B	
KQ15	Calciner No. 4 Product QC Bin C	
KQ16	Calciner No. 4 Product QC Bin D	
KCS7	Calciner No. 4 Product Screen DPCS	
KCS8	Calciner No. 8 Fines Screen DPCS	
PB04	Line No. 4 Product Belt	----
BS13	Bulk Product Silo No. 4-1	
BS14	Bulk Product Silo No. 4-2	
BS15	Bulk Product Silo No. 4-3	
BS16	Bulk Product Silo No. 4-4	
KLN1	Direct-Fired Rotary Calciner No. 1	
KLN2	Direct-Fired Rotary Calciner No. 2	
KLN3	Direct-Fired Rotary Calciner No. 3	
KLN4	Direct-Fired Rotary Calciner No. 4	
SD01	Spray Dryer No. 1	
SD02	Spray Dryer No. 2	
SD03	Spray Dryer No. 3	
SD04	Spray Dryer No. 4	
SD05	Spray Dryer No. 5	
SD06	Spray Dryer No. 6	
SD07	Spray Dryer No. 7	
SD08	Spray Dryer No. 8	
BLR1	Boiler No. 1	
BLR2	Boiler No. 2	
BLR3	Boiler No. 3	

Table D.3-1: Material Storage and Handling Emissions Units

Emission Unit ID No.	Emission Unit Description	Emission Unit Group ID Nos.
BLR4	Boiler No. 4	
EDG1	Emergency Generator No. 1	
EDG2	Emergency Generator No. 2	
EDG3	Emergency Generator No. 3	
EDG4	Emergency Generator No. 4	

PM emissions from the material storage and handling systems primarily result from crushing, grinding and conveying of raw material. Although additional material handling equipment exists at the facility, it is not listed in this table as they are wet processes and have no associated PM emissions. Control technologies such as a high efficiency baghouse, an electrostatic precipitator (ESP), and a wet scrubber, were evaluated for control of PM emissions from the material storage and handling systems.

Step 1: Identify all control technologies

In reviewing the BACT alternatives to control emissions of PM from material storage and handling systems, applicable BACT determinations and permits for non-metallic mineral processing plants were reviewed as summarized in Table D.3-2 below.

Table D.3-2: Summary of PM Control Technology Determinations for Material Storage and Handling Systems

Facility Name	Location	Agency	Database	Process Type[1]	Permit Date	Process Description	Controls/ Type	Emission Limits/description
Thoroughbred Generating Company, LLC	Henderson, KY	KY DAQ	RBLC	90.024	Oct-02	Reagent Prep Handling	Enclosures and Filters	0.05 g/dscm
GCC Dacotah	Rapid City, SD	SD DENR	RBLC	90.028	Apr-03	Raw Material Transfer	Fabric Filter	0.010 gr/dscf
Lehigh Cement Company	Mason City, IA	IA DNR	RBLC	90.028	Dec-03	Secondary Material Handling	Baghouse	0.010 gr/dscf
Superior Graphite Co. - Desulco Division	Christian, KY	KY DAQ	RBLC	90.024	Jun-04	Raw Material/Product Handling	Baghouse	0.096 lb/hr
J.M. Huber Corporation	Macon, GA	GA EPD	Title V permit	90.024	Mar-06	Storage Silos A-D, Calciner #1, Calciner Pre-grinders	Baghouse	0.015 gr/dscf
Big River Industries, Inc.	Erwinville, LA	LA DEQ	RBLC	90.024	Jun-06	Conveyor Systems and Stockpiles	Water Sprays and/or Partial Enclosure	0.10 lb/hr 0.43 tpy
Aggregate Industries – Sloan Quarry	Las Vegas, NV	Clark Co DAQM	RBLC	90.024	Dec-06	Aggregate/ cement products bagging and packing	Baghouse	0.088 lb/hr 0.0088 lb/ton 0.66 tpy
United States Gypsum Company	Norfolk, VA	VA DEQ	RBLC	90.024	Jun-06	Ball Mill	Fabric Filters and CEM Systems	0.10 lb/hr 0.4 tpy
CARBO – Toomsboro	Toomsboro, GA	GA EPD	Title V permit	90.024	Dec-09	Raw Material/Product Handling	Baghouse	0.010 gr/dscf
CARBO – McIntyre	McIntyre, GA	GA EPD	Title V permit	90.024	Dec-09	Raw Material/Product Handling	Baghouse	0.010 gr/dscf

[1] 90.024 = Nonmetallic Mineral Processing (excludes 90.017); 90.028 = Portland Cement Manufacturing

As a consequence of our review, a high efficiency baghouse, an electrostatic precipitator (ESP) and a wet scrubber are being considered as noted in Table D.3-3 below.

Table D.3-3: Evaluated Control Options for PM Emissions – Material Storage and Handling Systems

Option No.	Control Technology
1	High Efficiency Baghouse
2	Electrostatic Precipitator
3	Wet Scrubber

Option 1 – High Efficiency Baghouse

Baghouses have been used extensively during the last twenty-five years in the non-metallic mineral industry. They operate based on the principle that particles and flue gas are separated in tube-shaped filter bags arranged in parallel flow paths. The particulates are collected either on the outside (dirty gas flow from outside-to-inside) or the inside (dirty gas flow from inside-to-outside) of the bag. The main differences among the various types of fabric filter technologies are related to the type of bag cleaning method, including reverse-gas, shake-deflate, pulse-jet, and sonic cleaning. Of the four methods, the pulse-jet baghouse is generally used more often in the non-metallic mineral industry as it is smaller and usually more cost effective due to requiring less bag surface area for a given air flow rate.

Pulse-jet cleaning uses compressed air to force air through the bag and expand it. Once the fabric reaches its extension limit, dust separates from the bag and is carried away from the fabric surface by air escaping through the bag. This highly efficient system is able to achieve removal/control efficiencies as high as 99.9%.[10]

Option 2 - Electrostatic Precipitator (ESP)

Electrostatic precipitators (ESPs) are particle control devices that remove particles from flowing gas streams onto collector plates through the use of electrical forces. Typically, new ESPs can achieve design removal efficiencies for PM of up to above 99%[11]. While several factors determine ESP collection efficiency, the size of the ESP is most important as size determines treatment time; the longer a particle spends in the ESP, the greater its chance of being collected. Collection efficiency is also affected by dust resistivity, gas temperature, gas turbulence, chemical composition (of the dust and the gas), particle size distribution, and electric field strength.

ESPs typically have high capital, maintenance, and energy costs associated with their operation. In general, they are not well suited for use in processes that are highly variable as they are very sensitive to fluctuations in gas stream conditions (flow rates, temperatures, particulate and gas composition, and particulate loadings). ESPs are also difficult to install in sites that have limited space as they must be relatively large to obtain

[10] Discussion on high efficiency baghouse from US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.1, Subsections 1.1 and 1.2.3.

[11] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.3 Subsection 3.2.1.2 Table 3.8

the low gas velocities necessary for efficient PM collection. Certain particulates are difficult to collect due to extremely high or low resistivity characteristics. [12]

Option 3 – Wet Scrubber System

Wet scrubbers are primarily used to control PM through the impaction, diffusion, interception and/or absorption of the PM particles onto droplets of liquid. Collection efficiencies vary based on particle size distribution of the waste gas stream and scrubber type, and range from 40-99%[13].

Although wet scrubbers are more compact than baghouses or ESPs, they are associated with high pressure drops across the control system, and are limited to lower waste gas flow rates and temperatures. Additionally, they generate solid waste in the form of sludge which requires treatment and/or disposal. Wastewater is also produced when the particles come into contact with droplets of liquid. The moisture added to the gas stream can also lead to downstream corrosion and visibility problems, and is a consumptive use of limited water resources.[14]

Step 2: Eliminate technically infeasible options

Option 2 - Electrostatic Precipitator (ESP)

ESP's are not a feasible control option in cases where there is variability in air flow rate. In this regard, the material handling and storage units are not always operational, thus causing substantial variability in air flow rate. As such, ESP's are not considered a technically feasible control option to control PM from Material Storage and Handling Systems, and are not further considered as BACT.

Option 3 – Wet Scrubber System

As in the case of ESPs, wet scrubbers are also not a feasible control option in cases where there is variability in air flow rate. The material handling and storage units are not always operational, thus causing substantial variability in air flow rate. As such, wet scrubbers are not considered a technically feasible control option to control PM from material storage and handling systems, and are not further considered as BACT.

Step 3: Rank remaining technologies by control effectiveness

Table D.3-4: Ranking of Control Technology – Material Storage and Handling Systems

Control Technology Ranking	Option No.	Control Technology	Control Efficiency
1	1	High Efficiency Baghouse	99% +

12 Discussion on ESPs from US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.3, Subsections 3.1.1 and 3.1.4.

13 Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.2 Subsection 2.1

14 Discussion on wet scrubber systems from US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.2, Subsections 2.1 and 2.2.

Step 4: Evaluate most effective controls and document results

The energy, environmental, and economic impact analysis of all remaining control technologies is omitted from this analysis, as the highest-ranking control technology is being selected for implementation.

Step 5: Select BACT

Option 1 – High Efficiency Baghouse

A high efficiency baghouse with PM/PM_{10} and $PM_{2.5}$ emissions limitations as summarized below is proposed as BACT from the material storage and handling systems.

Table D.3-5: PM BACT Proposed for New Material Storage and Handling Systems

Emission Unit ID Nos.	BACT Limit
All equipment in Table D.3-1	The use of a high efficiency baghouse to control PM/PM_{10} emissions from each baghouse stack to 0.010 gr/dscf.
	The use of a high efficiency baghouse to control $PM_{2.5}$ emissions from each baghouse stack to 0.005 gr/dscf.

D.4 PM Review: Gas Fired Boilers Nos. 1 – 4

The facility is proposing to install four gas fired boilers, each with a maximum heat input of 9.8 MMBtu/hr. Due to very low PM emissions associated with the combustion of natural gas and propane, there are minimal particulate matter emissions from the gas fired boilers. Restricting the boilers to the combustion of natural gas or propane, and other control technologies, such as a high efficiency baghouse, an electrostatic precipitator (ESP), and a wet scrubber, were evaluated to control PM emissions from the gas fired boilers.

Step 1: Identify all control technologies

In reviewing the BACT alternatives to control emissions of PM from the four Gas Fired Boilers, applicable BACT determinations and permits for commercial and institutional size boilers have been reviewed, as summarized in Table D.4-1 below.

Table D.4-1: Summary of PM Control Technology Determinations for Gas Fired Boilers

Facility Name	Location	Agency	Database	Permit Date	Process Type[1]	Process Description	Controls / Type	Emission Limits/description
Steelcorr, Inc.	Bluewater, AR	AR DEQ	RBLC	Jul-04	13.310	Two Natural Gas Fired Boilers, 22.0 MMBtu/hr each	Exclusive use of Natural gas	0.0076 lb/MMBtu
Wisconsin Public Service	Marathon, WI	WI DNR	RBLC	Aug-04	13.310	Natural Gas Fired Boiler	Exclusive use of Natural gas	0.8 lbs/hr
Nukor Steel	Hickman, AR	ADEQ	RBLC	Apr-06	13.310	Natural Gas Fired Boilers, 12.6 MMBtu/hr each	Good Combustion Practices	0.30 lb/hr 1.30 tpy 0.0076 lb/MMBtu
Kern River Gas Transmission Company	Goodsprings, NV	Clark Co. DEQ	RBLC	May-06	13.310	Natural Gas Fired Boiler, 3.85 MMBtu/hr	Exclusive use of Natural gas	0.030 lb/hr 0.0078 lb/MMBtu
Harrah's Operating Company, Inc.	Clark, NV	Clark Co. DEQ	RBLC	Jan-07	13.310	Two Natural Gas Fired Boilers, 35.4 MMBtu/hr each	Exclusive use of Natural gas	0.260 lb/hr 0.0075 lb/MMBtu
Daimler Chrysler Corporation – Toledo Supplier Park Paint Shop	Lucas, OH	OH EPA	RBLC	May-07	13.310	Two Natural Gas Fired Boilers, 20.4 MMBtu/hr each	None Specified	0.04 lb/hr 0.27 lb/yr 0.0019 lb/MMBtu
Flopam, Inc	Iberville Parish, LA	LA DEQ	RBLC	Jun-10	13.310	Natural Gas Fired Boiler, 25.1 MMBtu/hr	Good Equipment Design and Proper Combustion Practices	0.10 lb/hr 0.005 lb/MMBtu

[1] 13.310 = external combustion of natural gas <100 MMBtu/hr

As a consequence of our review, a high efficiency baghouse, an electrostatic precipitator (ESP), a wet scrubber, and the exclusive use of natural gas or propane as fuel are being considered as noted in Table D.4-2 below.

Table D.4-2: Evaluated Control Options for PM Emissions – Gas Fired Boilers

Option No.	Control Technology
1	High Efficiency Baghouse
2	Electrostatic Precipitator
3	Wet Scrubber
4	Exclusive use of natural gas or propane as fuel

Option 1 – High Efficiency Baghouse

Baghouses have been used extensively during the last twenty-five years in the non-metallic mineral industry. They operate based on the principle that particles and flue gas are separated in tube-shaped filter bags arranged in parallel flow paths. The particulates are collected either on the outside (dirty gas flow from outside-to-inside) or the inside (dirty gas flow from inside-to-outside) of the bag. The main differences among the various types of fabric filter technologies are related to the type of bag cleaning method, including reverse-gas, shake-deflate, pulse-jet, and sonic cleaning. Of the four methods, the pulse-jet baghouse is generally used more often in the non-metallic mineral industry as it is smaller and usually more cost effective due to requiring less bag surface area for a given air flow rate.

Pulse-jet cleaning uses compressed air to force air through the bag and expand it. Once the fabric reaches its extension limit, dust separates from the bag and is carried away from the fabric surface by air escaping through the bag. This highly efficient system is able to achieve removal/control efficiencies as high as 99.9%.[15]

Option 2 - Electrostatic Precipitator (ESP)

Electrostatic precipitators (ESPs) are particle control devices that remove particles from flowing gas streams onto collector plates through the use of electrical forces. Typically, new ESPs can achieve design removal efficiencies for PM of up to above 99%[16]. While several factors determine ESP collection efficiency, the size of the ESP is most important as size determines treatment time; the longer a particle spends in the ESP, the greater its chance of being collected. Collection efficiency is also affected by dust resistivity, gas temperature, gas turbulence, chemical composition (of the dust and the gas), particle size distribution, and electric field strength.

ESPs typically have high capital, maintenance, and energy costs associated with their operation. In general, they are not well suited for use in processes that are highly variable as they are very sensitive to fluctuations in gas stream conditions (flow rates, temperatures, particulate and gas composition, and particulate loadings). ESPs are also difficult to install in sites that have limited space as they must be relatively large to obtain

[15] Discussion on high efficiency baghouse from US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.1, Subsections 1.1 and 1.2.3.
[16] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.3 Subsection 3.2.1.2 Table 3.8

the low gas velocities necessary for efficient PM collection. Certain particulates are difficult to collect due to extremely high or low resistivity characteristics. [17]

Option 3 – Wet Scrubber System

Wet scrubbers are primarily used to control PM and acid gases through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. Collection efficiencies vary based on particle size distribution of the waste gas stream and scrubber type, and range anywhere from 40-99%[18].

Although wet scrubbers are more compact than baghouses or ESPs, they are associated with high pressure drops across the control system, and are limited to lower waste gas flow rates and temperatures. Additionally, they generate solid waste in the form of sludge which requires treatment and/or disposal. Wastewater is also produced when the particles come into contact with droplets of liquid. The moisture added to the gas stream can also lead to downstream corrosion and visibility problems and is a consumptive use of limited water resources.[19]

Option 4 – Exclusive Use of Natural Gas or Propane as a fuel

Natural gas is a clean fuel that is readily available in the State of Georgia. The particulate matter content of natural gas and propane is much lower than other fuels, and its usage keeps PM emissions to a minimum. Due to the economic infeasibility of other control technologies, and the availability and benefits of using natural gas or propane as a fuel, the facility will accept federally enforceable permit conditions restricting Gas Fired Boiler Nos. 1 – 4 to the combustion of natural gas and propane only.

Step 2: Eliminate technically infeasible options

All of the above control technologies are technically feasible for purposes of this BACT determination.

Step 3: Rank remaining technologies by control effectiveness

Table D.4-3: Ranking of Control Technology – Gas Fired Boilers

Control Technology Ranking	Option No.	Control Technology	Control Efficiency
1 (tie)	1	High Efficiency Baghouse	99% +
1 (tie)	2	Electrostatic Precipitator	99% +
1 (tie)	3	Wet Scrubber	99% +
2	4	Exclusive use of natural gas or propane as fuel	N/A

[17] Discussion on ESPs from US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.3, Subsections 3.1.1 and 3.1.4.
[18] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.2 Subsection 2.1
[19] Discussion on wet scrubber systems from US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.2, Subsections 2.1 and 2.2.

Step 4: Evaluate most effective controls and document results

Option 1 – High Efficiency Baghouse

There is no indication that a baghouse has ever been utilized for controlling PM emissions from a gas fired boiler of this size, or with a similar magnitude of PM emissions. With the exclusive firing of natural gas or propane in the boilers, the estimated potential PM emissions for each boiler are approximately 0.328 tpy (See Volume I, Attachment B, Table 2). We believe at approximately 0.328 tpy of controlled PM, using a high efficiency baghouse to control PM would be economically infeasible. Therefore, high efficiency baghouses are not given further consideration as BACT for PM emissions from the boilers.

Option 2 - Electrostatic Precipitator (ESP)

Based on our review of known existing commercial and institutional size boilers in Georgia, as well as our review of all sources identified in the RACT/BACT/LAER database (as provided in Table D.4-1), there is no indication that ESPs have ever been utilized for controlling PM emissions from a gas fired boiler of this size, or with a similar magnitude of PM emissions. With the exclusive firing of natural gas or propane in the boilers, the estimated potential PM emissions for each boiler would be approximately 0.328 tpy. We believe at approximately 0.328 tpy of controlled PM, using an ESP to control PM would be economically infeasible. Therefore, ESPs are not given further consideration as BACT for PM emissions from the boilers.

Option 3 – Wet Scrubber System

There is no indication that a wet scrubber has ever been utilized for controlling PM emissions from a gas fired boiler of this size, or with a similar magnitude of PM emissions. With the exclusive firing of natural gas or propane in the boilers, the estimated potential PM emissions for each boiler are approximately 0.328 tpy. We believe at approximately 0.328 tpy of controlled PM, using a wet scrubber to control PM would be economically infeasible. Therefore, wet scrubbers are not given further consideration as BACT for PM emissions from the boilers.

Step 5: Select BACT

Option 4 – Exclusive Use of Natural Gas or Propane as a fuel

The exclusive use of natural gas or propane as fuel is proposed as BACT for PM/PM_{10} and $PM_{2.5}$ emissions for the four gas fired boiler (Emission Unit ID Nos. BLR1 – BLR4) as summarized below.

Table D.4-4: PM BACT Proposed for Gas Fired Boiler Nos. 1 – 4

Emission Unit ID Nos.	BACT Limit
BLR1 – BLR4	Exclusive use of natural gas or propane as fuel

D.5 PM Review: Emergency Generators Nos. 1 – 4

The facility is proposing to install four (4) diesel fired emergency generators rated at 2,280 kW (3,058 hp) each. Due to good combustion practices, use of these units during emergencies only, and low PM emissions associated with the combustion of diesel fuel, there are minimal particulate matter emissions from the diesel-fired emergency generators. Restricting the generators to the use of good combustion practices and other control technologies such as a high efficiency baghouse, an electrostatic precipitator (ESP), and a wet scrubber, were evaluated to control PM emissions from the four (4) diesel-fired emergency generators. The units will be manufacturer-certified as compliant with the Tier II standard requirements of 40 CFR 60, Subpart IIII emission standards for stationary compression-ignition engines. These standards already require dramatic reductions in PM emissions relative to the emissions of pre-2007 engines, and are the basis for the PM (PM/PM_{10} and $PM_{2.5}$) BACT baseline of 0.055 g/hp-hr.

All limits proposed are for direct $PM/PM_{10}/PM_{2.5}$, which is the combination of filterable and condensable fractions. The grain loading limits have been determined based on a 500 hr/year operating limit, and a 0.055 g/hp-hr emission limit per the Tier II standards of 40 CFR 60, Subpart IIII.

Step 1: Identify all control technologies

In reviewing the BACT alternatives to control emissions of PM from the four diesel-fired emergency generators, applicable BACT determinations and permits for diesel-fired internal combustion engines of comparable ratings have been reviewed, as summarized in Table D.5-1 below.

Table D.5-1: Summary of PM Control Technology Determinations for Internal Combustion Engines

Facility Name	Location	Database	Permit Date	Process Description[1]	Controls / Type	Emission Limits/ g/hp-hr Equivalent	
Arizona Clean Fuels Yuma, LLC	Pheonix, AZ	Class I Permit	Apr-05	Diesel Emergency Generator rated at 10.9 MMBtu/hr	None indicated	0.20 g/kW-hr	0.15 g/hp-hr
Marathon Petroleum Co., LLC – Garyville Refinery	Garyville, LA	RBLC	Dec-06	Diesel Emergency Generators (2) rated at 1,341 hp and 671 hp	Use of diesel with a sulfur content of 15 ppmv or less	0.0022 lb/hp-hr	0.998 g/hp-hr
Merck and Co.	Westpoint, PA	RBLC	Feb-07	Diesel mobile emergency generator	None indicated	0.16 g/bhp-hr	0.16 g/hp-hr
ADM Corn Processing - Cedar Rapids	Linn, IA	RBLC	Jun-07	Emergency generator	No specific control technology specified. Engine is required to meet limits established as BACT (Tier 2 nonroad).	0.15 g/bhp-hr	0.15 g/hp-hr
Creole Trail LNG Import Terminal	Cameron, LA	RBLC	Aug-07	Diesel emergency generators (2) rated at 2,168 hp each	Good combustion practices, good engine design, use of low sulfur/ash diesel	0.69 lb/hr	0.144 g/hp-hr
Tate & Lyle Ingredients Americas, Inc.	Webster, IA	RBLC	Sep-08	Diesel Emergency Generator rated at 700 kW	None indicated	0.200 g/kW-hr	0.149 g/hp-hr
Associated Electric Cooperative, Inc.	Chouteau, OK	RBLC	Jan-09	Diesel Emergency Generator rated at 2,200 hp	None indicated	0.200 g/kW-hr	0.149 g/hp-hr
Shady Hills Power Company Generating Station	Spring Hill, FL	RBLC	Jan-09	Diesel Emergency Generator rated at 2.5 MW	Use of ULSD (0.0015% S) and limit of 500 operating hours per year	0.400 g/hp-hr	0.400 g/hp-hr
MGM Mirage	Las Vegas, NV	RBLC	Nov-09	Diesel emergency generators (2) rated at 2,206 hp each	Turbocharger and good combustion practices	0.0001 lb/hp-hr	0.045 g/hp-hr
CARBO – Toomsboro	Toomsboro, GA	Title V Permit	Dec-09	Emergency Generators	Emission standards from new nonroad compression ignition engines specified in 40 CFR 89.112 and 40 CFR 89.113	0.055 g/bhp-hr	0.055 g/hp-hr

[1] All process types are 17.110 (large internal diesel combustion engines)

As a consequence of our review, a high efficiency baghouse, an electrostatic precipitator (ESP), a wet scrubber, and the use of good combustion practices are being considered as noted in Table D.5-2 below.

Table D.5-2: Evaluated Control Options for PM Emissions – Diesel Fired Emergency Generators

Option No.	Control Technology
1	High Efficiency Baghouse
2	Electrostatic Precipitator
3	Wet Scrubber
4	Good Combustion Practices

Option 1 – High Efficiency Baghouse

Baghouses have been used extensively during the last twenty-five years in the non-metallic mineral industry. They operate based on the principle that particles and flue gas are separated in tube-shaped filter bags arranged in parallel flow paths. The particulates are collected either on the outside (dirty gas flow from outside-to-inside) or the inside (dirty gas flow from inside-to-outside) of the bag. The main differences among the various types of fabric filter technologies are related to the type of bag cleaning method, including reverse-gas, shake-deflate, pulse-jet, and sonic cleaning. Of the four methods, the pulse-jet baghouse is generally used more often in the non-metallic mineral industry as it is smaller and usually more cost effective due to requiring less bag surface area for a given air flow rate.

Pulse-jet cleaning uses compressed air to force air through the bag and expand it. Once the fabric reaches its extension limit, dust separates from the bag and is carried away from the fabric surface by air escaping through the bag. This highly efficient system is able to achieve removal/control efficiencies as high as 99.9%.[20]

Option 2 - Electrostatic Precipitator (ESP)

Electrostatic precipitators (ESPs) are particle control devices that remove particles from flowing gas streams onto collector plates through the use of electrical forces. Typically, new ESPs can achieve design removal efficiencies for PM of up to above 99%[21]. While several factors determine ESP collection efficiency, the size of the ESP is most important as size determines treatment time; the longer a particle spends in the ESP, the greater its chance of being collected. Collection efficiency is also affected by dust resistivity, gas temperature, gas turbulence, chemical composition (of the dust and the gas), particle size distribution, and electric field strength.

ESPs typically have high capital, maintenance, and energy costs associated with their operation. In general, they are not well suited for use in processes that are highly variable as they are very sensitive to fluctuations in gas stream conditions (flow rates, temperatures, particulate and gas composition, and particulate loadings). ESPs are also

[20] Discussion on high efficiency baghouse from US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.1, Subsections 1.1 and 1.2.3.
[21] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.3 Subsection 3.2.1.2 Table 3.8

difficult to install in sites that have limited space as they must be relatively large to obtain the low gas velocities necessary for efficient PM collection. Certain particulates are difficult to collect due to extremely high or low resistivity characteristics.[22]

Option 3 – Wet Scrubber System

Wet scrubbers are primarily used to control PM and acid gases through the impaction, diffusion, interception and/or absorption of the pollutant onto droplets of liquid. Collection efficiencies vary based on particle size distribution of the waste gas stream and scrubber type, and range anywhere from 40-99%[23].

Although wet scrubbers are more compact than baghouses or ESPs, they are associated with high pressure drops across the control system, and are limited to lower waste gas flow rates and temperatures. Additionally, they generate solid waste in the form of sludge which requires treatment and/or disposal. Wastewater is also produced when the particles come into contact with droplets of liquid. The moisture added to the gas stream can also lead to downstream corrosion and visibility problems and is a consumptive use of limited water resources.[24]

Option 4 – Good Combustion Practices, Operating and Emission Limits

Due to the generators being operated during emergencies only, and the economic infeasibility of other control technologies, the facility will maintain good combustion practices in these units through the use of proper operational and maintenance procedures for minimizing PM emissions.

Step 2: Eliminate technically infeasible options

All of the above control technologies are technically feasible for purposes of this BACT determination.

Step 3: Rank remaining technologies by control effectiveness

Table D.5-3: Ranking of Control Technology – Diesel Fired Emergency Generators

Control Technology Ranking	Option No.	Control Technology	Control Efficiency
1 (tie)	1	High Efficiency Baghouse	99% +
1 (tie)	2	Electrostatic Precipitator	99% +
1 (tie)	3	Wet Scrubber	99% +
2	4	Good Combustion Practices	N/A

22 Discussion on ESPs from US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.3, Subsections 3.1.1 and 3.1.4.
23 Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.2 Subsection 2.1
24 Discussion on wet scrubber systems from US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 6.2, Subsections 2.1 and 2.2.

Step 4: Evaluate most effective controls and document results

Option 1 – High Efficiency Baghouse

There is no indication that a baghouse has ever been utilized for controlling PM emissions from a diesel-fired emergency generator of this size, or with a similar magnitude of PM emissions. With the use of good combustion practices in the generators, a proposed annual limit of 500 operating hours, and proposed PM limit of 0.055 g/hp-hr, the estimated potential PM emissions for each generator would be 0.093 tpy (See Volume I, Attachment B, table 2). We believe at this magnitude of uncontrolled PM, using a high efficiency baghouse to control PM would be economically infeasible. Therefore, high efficiency baghouses are not given further consideration as BACT for PM emissions from the diesel-fired emergency generators.

Option 2 - Electrostatic Precipitator (ESP)

There is no indication that ESPs have ever been utilized for controlling PM emissions from a diesel-fired emergency generator of this size, or with a similar magnitude of PM emissions. With the exclusive firing of diesel in the generators, and a proposed annual limit of 500 operating hours, the estimated potential PM emissions for each generator would be 0.093 tpy. We believe at this magnitude of uncontrolled PM, using an ESP to control PM would be economically infeasible. Therefore, ESPs are not given further consideration as BACT for PM emissions from the diesel-fired emergency generators.

Option 3 – Wet Scrubber System

There is no indication that a wet scrubber has ever been utilized for controlling PM emissions from diesel-fired emergency generators of this size, or with a similar magnitude of PM emissions. With the exclusive firing of diesel fuel in the generators and a proposed annual limit of 500 operating hours, the estimated potential PM emissions for each generator would be 0.093 tpy. We believe at this magnitude of uncontrolled PM, using a wet scrubber to control PM would be economically infeasible. Therefore, wet scrubbers are not given further consideration as BACT for PM emissions from the diesel-fired emergency generators.

Step 5 Select BACT

Option 4 – Good Combustion Practices, Operating and Emission Limits

The exclusive use of diesel as fuel, with a PM/PM_{10} and $PM_{2.5}$ emission limit of 0.055 g/bhp-hr, and a federally enforceable limit of 500 hours of operation per year each, is proposed as BACT for Diesel-fired Emergency Generator Nos. 1 – 4 (Emissions Unit ID Nos. EDG1 – EDG4) as summarized below.

Table D.5-4: PM BACT Proposed for Diesel Fired Emergency Generators Nos. 1 – 4

Emission Unit ID Nos.	BACT Limit
EDG1 – EDG4	Exclusive use of diesel as fuel with a PM/PM_{10} emission limit of 0.055 g/bhp-hr and maximum 500 hours of operation per year each.
	Exclusive use of diesel as fuel with a $PM_{2.5}$ emission limit of 0.055 g/bhp-hr and maximum 500 hours of operation per year each.

ATTACHMENT E

Detailed VOC BACT Analysis

VOLUME II, ATTACHMENT E
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E. Top-Down BACT Analysis: Volatile Organic Compounds (VOC)

E.1 VOC Review: Direct Fired Rotary Calciner Nos. 1 – 4

Volatile Organic Compounds (VOC) are emitted from the direct-fired rotary calciners due to incomplete combustion of fuel (natural gas and propane). VOC emissions can be minimized by combustion practices that promote high combustion temperatures and turbulent mixing of fuel and combustion air. Pre-combustion control technologies, such as good combustion techniques and fuel selection, including limitization of the design, operation, and maintenance of the calciner and combustion system and its efficient operation, and post-combustion control technologies, such as thermal oxidation, catalytic oxidation, carbon adsorption, and biofiltration, were evaluated for control of VOC emissions from the four direct-fired rotary calciners.

This analysis is based on baseline VOC emissions of 0.525 lb/hr or 2.30 tpy. This emission rate has been selected based on limited engineering testing along with AP-42 (Chapter 1.5, Table 1.5-1) emission factors and a heat input rating of 60 MMBtu/hr.

Step 1: Identify all control technologies

In reviewing the control technology alternatives to control emissions of VOC from the direct-fired rotary calciners, applicable BACT determinations and permits for non-metallic mineral processing plants have been reviewed, as summarized in Table E.1-1 below:

Table E.1-1: Summary of VOC Post-Combustion Control Technology Determinations for Kilns and Calciners

Facility Name	Location	Agency	Database	Process Type[1]	Permit Date	Process Description	Controls / Type	Emission Limits/ Description
Dalitalia LLC	Muskogee, OK	OK DEQ	RBLC	90.008	Oct-05	Natural Gas-fired Kiln	Good Combustion Techniques	2.35 lb/ton
United States Gypsum Company	Norfolk, VA	VA DEQ	RBLC	90.024	Jun-06	Natural Gas-Fired Board Drying Kiln	Pollution Prevention	5.8 lb/hr

[1] 90.008 = Clay and Fly Ash Sintering; 90.024 = Non-metallic Mineral Processing

As a consequence of our review, and the evaluation of other available control technology options, the use of carbon adsorption, regenerative thermal oxidation, catalytic oxidation, biofiltration, and good combustion techniques are being evaluated as potential BACT as noted in Table E.1-2 below.

Table E.1-2: Evaluated Control Options for VOC Emissions – Direct-fired Rotary Calciners (KLN1 – KLN4)

Option No.	Control Technology
1	Carbon Adsorption
2	Regenerative Thermal Oxidation
3	Catalytic Oxidation
4	Biofiltration
5	Pollution Prevention/Good Combustion Techniques

Option 1 – Carbon Adsorption

Carbon adsorbers typically employ activated carbon, which has an afinity to adsorb VOCs, along with a beneficially large surface area per unit volume. While variables such as the properties of the individual VOC being absorbed, the gas stream concentration of the VOC, and the gas stream temperature, will affect the efficiency of the control process, a VOC-laden gas stream passing over a bed of activated carbon will cause VOC to be adsorbed in the carbon bed. Over time, the adsorptive capacity of the carbon is consumed, as its surface area becomes saturated with adsorbate. When this occurs, the carbon can either be exchanged with fresh carbon, or treated through a regeneration process to release the adsorbate.

The regeneration process typically involves heating the carbon bed via steam injection, then drying and cooling the bed using fan-forced air. The exhaust from the vessel during the regeneration process is passed through a condenser/decanter to recover the VOC. Carbon adsorption has the advantage of being relatively effective on low-concentration gas streams, compatible with large airflow volumes, and more energy efficient in many cases compared to thermal or catalytic oxidation techniques. The control efficiency of a carbon adsorber, when properly maintained and operated, can be as high as 98%.[1] Although the use of a carbon adsorber has been found to be technically feasible in theory, our review indicates that a carbon adsorber has not been demonstrated in practice as a measure to control VOC emissions in the non-metallic minerals processing industry before. Thus, using a carbon adsorber on Direct-fired Rotary Calciner Nos. 1 – 4 would be considered experimental.

Option 2 – Regenerative Thermal Oxidation (RTO)

Volatile Organic Compounds can be oxidized to carbon dioxide and water at high temperatures (generally 300°F above the autoignition temperature of the VOC with a residence time of 0.5 to 1.0 seconds). Thermal oxidizers can recover heat energy using recuperative or regenerative methods. Regenerative thermal oxidizers can achieve a much higher heat recovery rate than recuperative thermal oxidizers. In the most recent publication of the EPA Air Pollution Control Cost Manual (2002), EPA provides cost correlations for regenerative thermal oxidizers for flue gas flow rates 10,000-100,000

[1] Per US EPA Document EPA 456/F-99-004, Choosing An Adsorption System for VOC: Carbon, Zeolite, or Polymers? May 1999, p. 16

scfm, and recuperative thermal oxidizers for flue gas flow rates 500-50,000 scfm.[2] Based on an approximate flow rate of 39,000 scfm from Direct-fired Rotary Calciner Nos. 1 – 4, costs to implement the use of regenerative thermal oxidizer to control VOC emissions have been estimated accordingly.

A regenerative thermal oxidizer (RTO) typically consists of multiple chambers (at least two) packed with ceramic media. The beds alternate such that the system recovers up to 95%[3] of the thermal energy during oxidation. The control efficiency of an RTO, when properly maintained and operated, can be as high as 98%.[3] Although the use of an RTO has been found to be technically feasible in theory, our review indicates that an RTO has not been demonstrated in practice as a measure to control VOC emissions from direct fired kilns/calciners in the non-metallic minerals industry before. Thus, using an RTO on Direct-fired Rotary Calciner Nos. 1 – 4 would be considered experimental.

Option 3 – Catalytic Oxidation

Catalytic oxidation is a post combustion control technique for reducing emissions of VOCs. A catalytic oxidation system is a passive reactor, which consists of a honeycomb grid of metal panels, typically coated with platinum or rhodium. The catalyst grid is placed in the exhaust where the optimum reaction temperature can be maintained (300°F – 900°F). The oxidation process takes place spontaneously, without the requirement for introducing reactants (such as ammonia) into the flue gas stream. The catalyst serves to lower the activation energy necessary for complete oxidation of these incomplete combustion byproducts to carbon dioxide. The active component that most catalytic oxidation systems utilize is platinum metal, which is applied over a metal or ceramic substrate. When properly operated and maintained, a catalytic oxidizer can achieve a control efficiency as high as 95%.[4] Although the use of a catalytic oxidizer has been found to be technically feasible in theory, there is no indication that it has ever been demonstrated in practice as a measure to control VOC emissions from direct fired kilns/calciners in the non-metallic minerals industry before. Thus, using a catalytic oxidizer on Direct-fired Rotary Calciner Nos. 1 – 4 would be considered experimental.

Option 4 – Biofiltration

Bioreactors use microbes to consume pollutants from a contaminated air stream. Microbes can easily decompose VOCs into CO_2 and water. The control efficiency of a bioreactor is influenced by temperature, moisture, nutrients, acidity, and microbe population. Microbes can survive at temperatures between 60 to 105°F in a moist, neutral environment (pH=7) and need to be fed a diet of balanced nutrients.

The US EPA identifies three types of bioreactors: the basic biofilter, the biotrickling filter, and the bioscrubber. The basic biofilter consists of a large flat surface covered with bed media, such as peat, bark, coarse soil, or gravel. Air moves through the bed and comes into contact with microbes, which then decompose the pollutants. Basic biofilters have significant disadvantages. The traditional design requires large open areas and

[2] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.5.1 Table 2.7
[3] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.2.1
[4] Per vendor experience and US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.4.3

provides no continuous liquid flow in which to adjust pH, keep moisture, or add nutrients. In a biotrickling filter, liquid is sprayed onto a plastic media, where a biofilm is formed. As the air passes through the media, pollutants are absorbed into the liquid phase and come into contact with the microbes. The continuous flow of liquid allows the operator to neutralize acid buildup and provide nutrients when required. The plastic bed can have a void space of up to 95%, which greatly reduces pressure drop across the packing, and the synthetic material is not consumed by the microbes. Bioscrubbers utilize a chemical scrubber and are more similar to chemical-processing equipment than other bioreactors. Discharge effluent is collected in a storage tank which allows additional time for the microbes to consume pollutants. In the US EPA Clean Air Technology Center's (CATC) report, "Using Bioreactors to Control Air Pollution",[5] bioscrubbers were shown to have much greater capital costs and slightly greater annual costs than combustion control devices. Biotrickling filters were therefore chosen as the most feasible form of bioreactor for Direct-fired Rotary Calciner Nos. 1 – 4, and are assumed to be 90% efficient in this analysis.[6]

Option 5 – Pollution Prevention/Good Combustion Techniques

Optimization of the design, operation, and maintenance of the calciner and combustion system is the primary mechanism available for lowering VOC. This process is often referred to as combustion controls. The factors involved include continuous mixing of air and fuel in the proper proportions, appropriate residence time, and suitable temperatures in the combustion chamber. As a result of the optimum conditions for combustion, VOC emissions can be minimized. Additionally, the high temperatures maintained in the calciners themselves also act to oxidize any VOC emissions from the burner. Finally, the use of natural gas and propane[7] as the dedicated fuels used will result in minimized VOC emissions.

Step 2: Eliminate technically infeasible options

All of the above control technologies options are technically feasible.

Step 3: Rank remaining control technologies by control effectiveness

Table E.1-3: Ranking of Control Technology – Direct-fired Rotary Calciner Nos. 1 – 4
Baseline Emissions = 2.30 tpy VOC each calciner

Control Technology Ranking	Option No.	Control Technology	Control Efficiency	VOC Reductions (tpy)
1 (tie)	1	Carbon Adsorption	98%	2.25
1 (tie)	2	Regenerative Thermal Oxidation	98%	2.25
2	3	Catalytic Oxidation	95%	2.18
3	4	Biofiltration	90%	2.07
4	5	Pollution Prevention/ Good Combustion Techniques	N/A	N/A

[5] See http://www.epa.gov/ttn/catc/dir1/fbiorect.pdf
[6] Discussion on Biofiltration from EPA Document EPA-456/R-03-003, Using Biorectors to Control Air Pollution. Sept. 2003
[7] Propane will be used in only during periods of natural gas curtailment.

Step 4: Evaluate most effective controls and document results

Table E.1-4 below summarizes the energy, environmental, and economic impacts of all remaining control technologies.

Table E.1-4: BACT Control Analysis – Direct-fired Rotary Calciner Nos. 1 – 4

						Change in Facility Emissions[2]					
Option No.	Control Technology	Annualized Cost	Cost Effectiveness ($/ton VOC Reduced)	Total Energy Consumed (MMBtu/yr)	Water Usage (MGD)	NO_x (tpy)	**VOC (tpy)**	CO (tpy)	GHG (tpy CO_2e)	SO_2 (tpy)	Total PM[1] (tpy)
1	Carbon Adsorption	$975,076	$432,692	386	Nil	0	**-2.25**	0	+7.42	0	0
2	Regenerative Thermal Oxidation	$1,614,664	$716,511	81,836	0	+3.97	**-2.25**	+3.33	+4,796	+0.024	+0.302
3	Catalytic Oxidation	$1,548,336	$708,775	71,508	0	+3.27	**-2.18**	+2.75	+3,959	+0.020	+0.249
4	Biofiltration	$1,680,283	$811,907	3,152	0.012	0	**-2.07**	0	+5.45	0	0
5	Good Combustion Techniques	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A	N/A

[1] Total PM includes filterable and condensables. All PM is assumed to be <2.5 microns.
[2] Collateral emissions detailed in Table E.5-5

As shown in Table E.1-4, the estimated annualized cost effectiveness exceed the level at which the installation of add-on pollution control devices can be deemed reasonable. In addition, the resources and energy that would be required to operate the control technologies are not justified based on the resulting environmental and economic impacts.

Step 5: Select BACT

In order to effectively control VOC emissions from the four process direct-fired rotary calciners (Emission Unit ID Nos. KLN1 – KLN4), good combustion techniques and the dedicated use of natural gas and propane as fuelare being proposed as BACT, as summarized below.

Table E.1-5: VOC BACT Proposed for Direct-fired Rotary Calciner Nos. 1 – 4

Emission Unit ID Nos.	BACT
KLN1 – KLN4	The use of good combustion techniques and exclusive use of natural gas and propane as fuels

E.2 VOC Review: Spray Dryers Nos. 1 – 8

Volatile Organic Compounds (VOC) are emitted from the spray dryers due to incomplete combustion of fuel (natural gas and propane). Additionally, the slurry injected into the spray dryers contains an additive with <1% methanol by weight. This methanol, an impurity, is assumed to be driven off in the spray dryers as the operating temperature of the spray dryer is well above 148.4°F (estimated boiling point for methanol). Combustion VOC emissions can be minimized by combustion practices that promote high combustion temperatures and turbulent mixing of fuel and combustion air. Pre-combustion control technologies, such as good combustion techniques and fuel selection, including optimization of the design, operation, and maintenance of the spray dryer and combustion system and its efficient operation, as well as post-combustion control technologies, such as thermal oxidation, catalytic oxidation, carbon adsorption, and biofiltration, were evaluated for control of VOC emissions from the spray dryers.

This analysis is based on baseline VOC emissions of 3.11 lb/hr or 13.64 tpy per line (each line includes 2 dryers). This VOC emission rate has been selected based on the sum of VOC emissions and fuel combustion and process emissions of methanol, which are determined on a mass balance basis. Methanol emissions are approximately 10.04 tpy per line based on a per line additive usage of 5,500 lbs/day composed of 1% methanol. Fuel combustion emissions, 0.822 tpy per line, are based on AP-42 (Chapters 1.4 and 1.5) emission factors for the unit's allowable fuels at their respective maximum heat input ratings. The higher of the emission factors between natural gas and propane was used to determine emission rates. This evaluation is being performed on a per line basis instead of a per spray dryer basis as facility-wide usage of additive is monitored and recorded in terms of lbs/day per line.

Step 1: Identify all control technologies

In reviewing the control technology alternatives to control emissions of VOC from the Spray Dryers, all applicable BACT determinations and permits for commercial and institutional size boilers and furnaces have been reviewed, as summarized in Table E.2-1 below:

Table E.2-1: Summary of VOC Post-Combustion Control Technology Determinations for Spray Dryers

Facility Name	Location	Agency	Database	Process Type[1]	Permit Date	Process Description	Controls / Type	Emission Limits/ Description
Dalitalia LLC	Muskogee, OK	OK DEQ	RBLC	90.017	Oct-05	Natural gas-fired Spray Dryers	Good Combustion Techniques	2.5 lb/ton

[1]90.017 = Calciners and Dryers and Mineral Processing Facilities

As a consequence of our review, and the evaluation of other available control technology options, the use of carbon adsorption, regenerative thermal oxidation, catalytic oxidation, biofiltration, and good combustion techniques are the control technologies being evaluated as BACT as noted in Table E.2-2 below.

Table E.2-2: Evaluated Control Options for VOC Emissions – Spray Dryers (SD01 – SD08)

Option No.	Control Technology
1	Carbon Adsorption
2	Regenerative Thermal Oxidation
3	Catalytic Oxidation
4	Biofiltration
5	Pollution Prevention / Good Combustion Techniques

Option 1 – Carbon Adsorption

Carbon adsorbers typically employ activated carbon, which has an afinity to adsorb VOCs, along with a beneficially large surface area per unit volume. While variables such as the properties of the individual VOC being absorbed, the gas stream concentration of the VOC, and the gas stream temperature will affect the efficiency of the control process, a VOC-laden gas stream passing over a bed of activated carbon will cause VOC to be adsorbed in the carbon bed. Over time, the adsorptive capacity of the carbon is consumed, as its surface area becomes saturated with adsorbate. When this occurs, the carbon can either be exchanged with fresh carbon, or treated through a regeneration process to release the adsorbate.

The regeneration process typically involves heating the carbon bed via steam injection, then drying and cooling the bed using fan-forced air. The exhaust from the vessel during the regeneration process is passed through a condenser/decanter to recover the VOC. Carbon adsorption has the advantage of being relatively effective on low-concentration gas streams, compatible with large airflow volumes, and more energy efficient in many cases compared to thermal or catalytic oxidation techniques. The control efficiency of a carbon adsorber, when properly maintained and operated, can be as high as 98%.[8] Although the use of a carbon adsorber has been found to be technically feasible in theory, our review indicates that a carbon adsorber has not been demonstrated in practice as a measure to control VOC emissions in the non-metallic minerals processing industry before. Thus, using a carbon adsorber on Spray Dryer Nos. 1 – 8 would be considered experimental.

Option 2 – Regenerative Thermal Oxidation (RTO)

Volatile Organic Compounds can be oxidized to carbon dioxide and water at high temperatures (generally 300°F above the autoignition temperature of the VOC with a residence time of 0.5 to 1.0 seconds). Thermal oxidizers can recover heat energy using recuperative or regenerative methods. Regenerative thermal oxidizers can achieve a much higher heat recovery rate than recuperative thermal oxidizers. In the most recent publication of the EPA Air Pollution Control Cost Manual (2002), EPA provides cost correlations for regenerative thermal oxidizers for flue gas flow rates 10,000-100,000

[8] Per US EPA Document EPA 456/F-99-004, Choosing An Adsorption System for VOC: Carbon, Zeolite, or Polymers? May 1999, p. 16

scfm, and recuperative thermal oxidizers for flue gas flow rates 500-50,000 scfm.[9] Based on an approximate flow rate of 92,000 scfm per line (46,000 scfm per spray dryer) from Spray Dryer Nos. 1 – 8, costs to implement the use of regenerative thermal oxidizer to control VOC emissions have been estimated accordingly.

A regenerative thermal oxidizer (RTO) typically consists of multiple chambers (at least two) packed with ceramic media. The beds alternate such that the system recovers up to 95%[9, 10] of the thermal energy during oxidation. The control efficiency of an RTO, when properly maintained and operated, can be as high as 98%.[10] Although the use of an RTO has been found to be technically feasible in theory, our review indicates that an RTO has not been demonstrated in practice as a measure to control VOC emissions from spray dryers in the non-metallic minerals industry before. Thus, using an RTO on Spray Dryer Nos. 1 – 8 would be considered experimental.

Option 3 – Catalytic Oxidation

Catalytic oxidation is a post combustion control technique for reducing emissions of methanol and other VOCs. A catalytic oxidation system is a passive reactor, which consists of a honeycomb grid of metal panels, typically coated with platinum or rhodium. The catalyst grid is placed in the exhaust where the optimum reaction temperature can be maintained (300°F – 900°F). The catalyst serves to increase reaction rates, thereby enabling the oxidation of hydrocarbons at lower reaction temperatures than in conventional thermal oxidizers. When properly operated and maintained, a catalytic oxidizer can achieve a control efficiency as high as 95%.[11] Although the use of a catalytic oxidizer has been found to be technically feasible in theory, there is no indication that it has ever been demonstrated in practice as a measure to control VOC in this industry before. Thus, using a catalytic oxidizer on Spray Dryers Nos. 1 – 8 would be considered experimental.

Option 4 – Biofiltration

Bioreactors use microbes to consume pollutants from a contaminated air stream. Microbes can easily decompose VOCs into CO_2 and water. The control efficiency of a bioreactor is influenced by temperature, moisture, nutrients, acidity, and microbe population. Microbes can survive at temperatures between 60 to 105°F in a moist, neutral environment (pH=7) and need to be fed a diet of balanced nutrients.

The US EPA identifies three types of bioreactors: the basic biofilter, the biotrickling filter, and the bioscrubber. The basic biofilter consists of a large flat surface covered with bed media, such as peat, bark, coarse soil, or gravel. Air moves through the bed and comes into contact with microbes, which then decompose the pollutants. Basic biofilters have significant disadvantages. The traditional design requires large open areas and provides no continuous liquid flow in which to adjust pH, keep moisture, or add nutrients. In a biotrickling filter, liquid is sprayed onto a plastic media, where a biofilm is formed. As the air passes through the media, pollutants are absorbed into the liquid phase

[9] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.5.1 Table 2.7
[10] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.2.1
[11] Per vendor experience and US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.4

and come into contact with the microbes. The continuous flow of liquid allows the operator to neutralize acid buildup and provide nutrients when required. The plastic bed can have a void space of up to 95%, which greatly reduces pressure drop across the packing, and the synthetic material is not consumed by the microbes. Bioscrubbers utilize a chemical scrubber and are more similar to chemical-processing equipment than other bioreactors. Discharge effluent is collected in a storage tank which allows additional time for the microbes to consume pollutants. In the US EPA Clean Air Technology Center's (CATC) report, "Using Bioreactors to Control Air Pollution",[12] bioscrubbers were shown to have much greater capital costs and slightly greater annual costs than combustion control devices. Biotrickling filters were therefore chosen as the most feasible form of bioreactor for Spray Dryer Nos. 1 – 8, and are assumed to be 90% efficient in this analysis.[13]

Option 5 – Pollution Prevention / Good Combustion Techniques

Optimization of the design, operation, and maintenance of the spray dryer and combustion system is the primary mechanism available for lowering VOC. This process is often referred to as combustion controls. The factors involved include continuous mixing of air and fuel in the proper proportions, appropriate residence time, and suitable temperatures in the combustion chamber. As a result of the optimum conditions for combustion, VOC emissions can be minimized. Additionally, continued use of an additive with the minimum amount of methanol and the use of natural gas and propane[14] as dedicated used will result in minimized VOC emissions.

Step 2: Eliminate technically infeasible options

All of the above control technologies options are technically feasible.

Step 3: Rank remaining control technologies by control effectiveness

Table E.2-3: Ranking of Control Technology – Spray Dryer Nos. 1 – 8
Baseline Emissions = 13.64 tpy VOC Per Line (2 Spray Dryers)

Control Technology Ranking	Option No.	Control Technology	Control Efficiency	VOC Reductions (tpy)
1	1	Carbon Adsorption	98%	13.37
2	2	Regenerative Thermal Oxidation	98%	13.37
3	3	Catalytic Oxidation	95%	12.96
4	4	Biofiltration	90%	12.28
5	5	Pollution Prevention / Good Combustion Techniques	N/A	N/A

[12] See http://www.epa.gov/ttn/catc/dir1/fbiorect.pdf
[13] Discussion on Biofiltration from EPA Document EPA-456/R-03-003, Using Biorectors to Control Air Pollution. Sept. 2003
[14] Propane will be used in only in periods of natural gas curtailment.

Step 4: Evaluate most effective controls and document results

Table E.2-4 below summarizes the energy, environmental, and economic impacts of all remaining control technologies.

Table E.2-4: BACT Control Analysis – Spray Dryer Nos. 1 – 8 (per line)

						Change in Facility Emissions[2]					
Option No.	Control Technology	Annualized Cost	Cost Effectiveness ($/ton VOC Reduced)	Total Energy Consumed (MMBtu/yr)	Water Usage (MGD)	NO_x (tpy)	**VOC (tpy)**	CO (tpy)	GHG (tpy CO_2e)	SO_2 (tpy)	Total PM[1] (tpy)
1	Carbon Adsorption	$421,038	$31,498	714	Nil	Nil	**-13.37**	Nil	+44.1	Nil	Nil
2	Regenerative Thermal Oxidation	$1,994,360	$149,198	172,840	0	+8.38	**-13.37**	+7.04	+10,160	+0.050	+0.637
3	Catalytic Oxidation	$2,439,706	$188,278	197,014	0	+9.19	**-12.96**	+7.72	+11,134	+0.055	+0.699
4	Biofiltration	$1,825,419	$148,698	6,344	0.025	0	**-12.28**	0	+32.3	0	0
5	Good Combustion Techniques	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A	N/A

[1] Total PM includes filterables and condensables. All PM assumed to be <2.5 microns.
[2] Collateral emissions detailed in Table E.6-5

As shown in Table E.2-4, the estimated annual cost effectiveness exceed the level at which the installation of add-on pollution control devices can be deemed reasonable. In addition, the resources and energy that would be required to operate the control technologies are not justified based on the resulting environmental and economic impacts.

Step 5: Select BACT

In order to effectively control VOC emissions from the four spray dryer lines (eight process spray dryers, Emission Unit ID Nos. SD01 – SD08), good combustion techniques and the dedicated use of natural gas and propane as fuel, in addition to a 12-month rolling total VOC emissions limit of 13.64 tpy, is being proposed as BACT for each spray dryer line. Table E.2-5 summarizes the BACT determination requirements being proposed for the eight spray dryers.

Table E.2-5: VOC BACT Proposed for Spray Dryer Nos. 1 – 8

Processing Line	Emission Unit ID Nos.	BACT
1	SD01 and SD02	Pollution Prevention with a VOC emission limit of 13.64 tons per twelve-month rolling total period for Spray Dryer Nos. 1 and 2, combined.
2	SD03 and SD04	Pollution Prevention with a VOC emission limit of 13.64 tons per twelve-month rolling total period for Spray Dryer Nos. 3 and 4, combined.
3	SD05 and SD06	Pollution Prevention with a VOC emission limit of 13.64 tons per twelve-month rolling total period for Spray Dryer Nos. 5 and 6, combined.
4	SD07 and SD08	Pollution Prevention with a VOC emission limit of 13.64 tons per twelve-month rolling total period for Spray Dryer Nos. 7 and 8, combined.

E.3 VOC Review: Gas Fired Boilers Nos. 1 – 4

Volatile Organic Compounds (VOC) are emitted from the boilers due to incomplete combustion of fuel (natural gas and propane). Combustion VOC emissions can be minimized by practices that promote high combustion temperatures and turbulent mixing of fuel and combustion air. Pre-combustion control technologies, such as good combustion techniques and fuel selection, including optimization of the design, operation, and maintenance of the boiler and combustion system and its efficient operation, as well as post-combustion control technologies, such as thermal oxidizers, catalytic oxidizers, carbon adsorption, and biofiltration, were evaluated for control of VOC emissions from the boilers.

This analysis is based on baseline VOC emissions of 0.086 lb/hr or 0.375 tpy. This emission rate has been selected based on AP-42 (Chapters 1.4 and 1.5) factors for the unit's allowable fuels at their respective maximum heat input ratings. The higher of the emission factors between natural gas and propane was used to determine emission rates.

Step 1: Identify all control technologies

In reviewing the control technology alternatives to control emissions of VOC from the boilers, applicable BACT determinations and permits for commercial and institutional size boilers and furnaces have been reviewed, as summarized in Table E.3-1 below:

Table E.3-1: Summary of VOC Control Technology Determinations for Gas Fired Boilers

Facility Name	Location	Agency	Data-base	Permit Date	Process Description[1]	Controls / Type	Emission Limits/ Description
Duke Energy Hanging Rock, LLC	Ironton, OH	OH EPA	RBLC	Dec-04	30.6 MMBtu/hr Natural Gas Fired Boilers (2) each	None Specified	0.490 lb/hr 0.740 ton per 12-mo rolling period 0.016 lb/MMBtu
Nukor Steel	Hickman, AR	ADEQ	RBLC	Apr-06	12.6 MMBtu/hr Natural Gas Fired Boilers each	Good Combustion Practice	0.2 lb/hr 0.9 tpy 0.0055 lb/MMBtu
Kern River Gas Transmission Company	Goodsprings, NV	Clark Co. DEQ	RBLC	May-06	3.85 MMBtu/hr Natural Gas Fired Boiler	Good Combustion Practice	0.020 lb/hr 0.005 lb/MMBtu
Harrah's Operating Company, Inc.	Clark, NV	Clark Co. DEQ	RBLC	Jan-07	35.4 MMBtu/hr Natural Gas Fired Boilers (2) each	Good Combustion Design	0.180 lb/hr 0.005 lb/MMBtu
Daimler Chrysler Corporation – Toledo Supplier Park Paint Shop	Lucas, OH	OH EPA	RBLC	May-07	20.4 MMBtu/hr Natural Gas Fired Boilers (2) each	None Specified	0.110 lb/hr 0.5 tpy 0.0054 lb/MMBtu
Associative Electric Cooperative, Inc – Chouteau Power Plant	Chouteau, OK	OK DEQ	RBLC	Jan-09	33.5 MMBtu/hr Natural Gas Fired Boiler	Good Combustion Techniques	0.540 lb/hr 0.016 lb/MMBtu[2]
Flopam, Inc	Iberville Parish, LA	LA DEQ	RBLC	June-10	25.1 MMBtu/hr Natural Gas Fired Boiler	Good Equipment Design and Proper Combustion Practices	0.003 lb/MMBtu

[1]All Processes are type 13.310, external combustion of natural gas <100 MMBtu/hr
[2]Implied emission rate calculated by Smith Aldridge to facilitate comparison across determinations

As a consequence of our review, and the evaluation of other available control technology options, the use of carbon adsorption, recuperative thermal oxidation, catalytic oxidation, biofiltration, and good combustion techniques are the control technologies being evaluated as BACT as noted in Table E.3-2 below.

Table E.3-2: Evaluated Control Options for VOC Emissions – Boilers (BLR1 – BLR4)

Option No.	Control Technology
1	Carbon Adsorption
2	Recuperative Thermal Oxidation
3	Catalytic Oxidation
4	Biofiltration
5	Pollution Prevention/Good Combustion Techniques

Option 1 – Carbon Adsorption

Carbon adsorbers typically employ activated carbon, which has an afinity to adsorb VOCs, along with a beneficial large surface area per unit volume. While variables such as the properties of the individual VOC being absorbed, the gas stream concentration of the VOC, and the gas stream temperature will affect the efficiency of the control process, a VOC-laden gas stream passing over a bed of activated carbon will cause VOC to be adsorbed in the carbon bed. Over time, the adsorptive capacity of the carbon is consumed, as its surface area becomes saturated with adsorbate. When this occurs, the carbon can either be exchanged with fresh carbon, or treated through a regeneration process to release the adsorbate.

The Cost Manual's cost correlations for the regeneration process are only accurate for gas flow rates ranging from 4,000-500,000 acfm.[15] As Boiler Nos. 1 – 4 operate at gas flow rates less than 2,500 acfm, it is more appropriate to analyze them for canister-type adsorbers which are normally limited to controlling lower volume gas streams. Once the carbon reaches a certain VOC content, the unit is shut down, and either the carbon or the canister is replaced. Each canister unit consists of a vessel, activate carbon, inlet connection and distributor leading to the carbon bed, and an outlet connection for the purified gas stream. In theory, a canister unit would remain in service longer than a regenerable unit would stay in its absorption cycle due to a higher theoretical capacity for fresh carbon compared to carbon regenerated on site. Canister systems still maintain the same control efficiency as fixed-bed units of 98%.[16, 17]

Option 2 – Recuperative Thermal Oxidation

Volatile Organic Compounds can be oxidized to carbon dioxide and water at high temperatures (generally 300°F above the autoignition temperature of the VOC with a residence time of 0.5 to 1.0 seconds). Thermal oxidizers can recover heat energy using recuperative or regenerative methods. Regenerative thermal oxidizers can achieve a much

[15] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 1.3.1.3
[16] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 1.4.5
[17] Carbon adsorption discussion per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.1, Subsection 1.1.2.

higher heat recovery rate than recuperative thermal oxidizers. In the most recent publication of the EPA Air Pollution Control Cost Manual (2002), EPA provides cost correlations for regenerative thermal oxidizers for flue gas flow rates 10,000-100,000 scfm, and recuperative thermal oxidizers for flue gas flow rates 500-50,000 scfm.[18] Based on an approximate flow rate of 1,598 scfm from Boiler Nos. 1 – 4 each, costs to implement the use of recuperative thermal oxidizer to control VOC emissions have been estimated accordingly.

In a recuperative thermal oxidizer, the exhaust air is preheated by means of a heat exchanger before entering the combustion chamber. The hot exhaust from the combustion chamber is then fed through the other side of the heat exchanger to provide the preheating of intake air. Through this means, up to 70%[18, 19] of the heat energy of the exhaust gas can be recovered, allowing for a reduction in fuel consumption. While this degree of heat recovery is less than is possible using the regenerative mechanism, the capital cost of the recuperative design can be substantially lower, which can, in some cases, offset the additional fuel consumption of the recuperative design. The control efficiency of aRecuperative Thermal Oxidizer, when properly maintained and operated, can be as high as 98%.[18]

Option 3 – Catalytic Oxidation

Catalytic oxidation is a post combustion control technique for reducing emissions of methanol and other VOCs. A catalytic oxidation system is a passive reactor, which consists of a honeycomb grid of metal panels, typically coated with platinum or rhodium. The catalyst grid is placed in the exhaust where the optimum reaction temperature can be maintained (300°F – 900°F). The catalyst serves to increase reaction rates, thereby enabling the oxidation of hydrocarbons at lower reaction temperatures than in conventional thermal oxidizers. When properly operated and maintained, a catalytic oxidizer can achieve a control efficiency as high as 95%.[20]

Option 4 – Biofiltration

Bioreactors use microbes to consume pollutants from a contaminated air stream. Microbes can easily decompose, VOCs into CO_2 and water. The control efficiency of a bioreactor is influenced by temperature, moisture, nutrients, acidity, and microbe population. Microbes can survive at temperatures between 60 to 105°F in a moist, neutral environment (pH=7) and need to be fed a diet of balanced nutrients.

The US EPA identifies three types of bioreactors: the basic biofilter, the biotrickling filter, and the bioscrubber. The basic biofilter consists of a large flat surface covered with bed media, such as peat, bark, coarse soil, or gravel. Air moves through the bed and comes into contact with microbes, which then decompose the pollutants. Basic biofilters have significant disadvantages. The traditional design requires large open areas and provides no continuous liquid flow in which to adjust pH, keep moisture, or add nutrients. In a biotrickling filter, liquid is sprayed onto a plastic media, where a biofilm is

[18] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.5.1 Table 2.7
[19] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.2.1
[20] Per vendor experience and US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.4.3

formed. As the air passes through the media, pollutants are absorbed into the liquid phase and come into contact with the microbes. The continuous flow of liquid allows the operator to neutralize acid buildup and provide nutrients when required. The plastic bed can have a void space of up to 95%, which greatly reduces pressure drop across the packing, and the synthetic material is not consumed by the microbes. Bioscrubbers utilize a chemical scrubber and are more similar to chemical-processing equipment than other bioreactors. Discharge effluent is collected in a storage tank which allows additional time for the microbes to consume pollutants. In the US EPA Clean Air Technology Center's (CATC) report, "Using Bioreactors to Control Air Pollution",[21] bioscrubbers were shown to have much greater capital costs and slightly greater annual costs than combustion control devices. Biotrickling filters were therefore chosen as the most feasible form of bioreactor for Boiler Nos. 1 – 4, and are assumed to be 90% efficient in this analysis.[22]

Option 5 – Pollution Prevention / Good Combustion Techniques

Optimization of the design, operation, and maintenance of the boiler and combustion system is the primary mechanism available for lowering VOC. This process is often referred to as combustion controls. The factors involved include continuous mixing of air and fuel in the proper proportions, appropriate residence time, and suitable temperatures in the combustion chamber. As a result of the optimum conditions for combustion, VOC emissions can be minimized. Additionally, the use of natural gas and propane[23] as the dedicated fuels for these units will result in minimized VOC emissions.

Step 2: Eliminate technically infeasible options

All of the above control technologies options are technically feasible.

Step 3: Rank remaining control technologies by control effectiveness

Table E.3-3: Ranking of Control Technology – Boiler Nos. 1 – 4
Baseline Emissions = 0.375 tpy VOC for each Boiler

Control Technology Ranking	Option No.	Control Technology	Control Efficiency	VOC Reductions (tpy)
1	1	Carbon Adsorption	98%	0.368
2	2	Recuperative Thermal Oxidation	98%	0.368
3	3	Catalytic Oxidation	95%	0.356
4	4	Biofiltration	90%	0.338
5	5	Pollution Prevention/ Good Combustion Techniques	N/A	N/A

[21] See http://www.epa.gov/ttn/catc/dir1/fbiorect.pdf
[22] Discussion on Biofiltration from EPA Document EPA-456/R-03-003, Using Biorectors to Control Air Pollution. Sept. 2003
[23] Propane will be used only during periods of natural gas curtailment.

Step 4: Evaluate most effective controls and document results

Table E.3-4 below summarizes the energy, environmental, and economic impacts of all remaining control technologies.

Table E.3-4: BACT Control Analysis – Boiler Nos. 1 – 4

						Change in Emissions[2]					
Option No.	Control Technology	Annualized Cost	Cost Effectiveness ($/ton VOC Reduced)	Total Energy Consumed (MMBtu/yr)	Water Usage (MGD)	NO_x (tpy)	**VOC (tpy)**	CO (tpy)	GHG (tpy CO_2e)	SO_2 (tpy)	Total PM[1] (tpy)
1	Carbon Adsorption	$35,618	$96,918	0	0	0	**-0.368**	0	+1.07	0	0
2	Recuperative Thermal Oxidation	$205,475	$559,115	8,298	0	+0.405	**-0.368**	+0.340	+490	+0.002	+0.031
3	Catalytic Oxidation	$147,646	$414,444	3,088	0	+0.142	**-0.356**	+0.119	+172	+0.001	+0.011
4	Biofiltration	$115,433	$342,022	131	Nil	0	**-0.338**	0	+0.939	0	0
5	Good Combustion Techniques	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A	N/A

[1] Total PM includes filterables and condensables. All PM assumed to be <2.5 microns.
[2] Collateral emissions detailed in Table E.7-5

As shown in Table E.3-4, the estimated annualized cost effectiveness exceeds the level at which the installation of add-on pollution control devices can be deemed reasonable. In addition, the resources and energy that would be required to operate the control technologies are not justified based on the resulting environmental and economic impacts.

Step 5: Select BACT

In order to effectively control VOC emissions from the four process boilers (Emission Unit ID Nos. BLR1 – BLR4), good combustion techniques and the dedicated use of natural gas and propane as fuel is being proposed as BACT as summarized below.

Table E.3-5: VOC BACT Proposed for Boiler Nos. 1 – 4

Emission Unit ID Nos.	BACT
BLR1 – BLR4	The use of good combustion techniques and dedicated use of natural gas and propane as fuels to control emissions from the boilers.

E.4 VOC Review: Emergency Generator Nos. 1 – 4

Volatile Organic Compounds (VOC) are emitted from the emergency generators due to incomplete combustion of diesel fuel. Combustion VOC emissions can be minimized by combustion practices that promote high combustion temperatures and turbulent mixing of fuel and combustion air. Pre-combustion control technologies, such as good combustion techniques and fuel selection, including optimization of the design, operation, and maintenance of the generator's engine and its efficient operation, as well as post-combustion control technologies, such as thermal oxidation, catalytic oxidation, carbon adsorption, and biofiltration, were evaluated for control of VOC emissions from the emergency generators.

This analysis is based on baseline VOC emissions of 1.65 lb/hr or 0.413 tpy. This emission rate has been selected based on AP-42 (Chapters 1.4 and 1.5) emission factors for the unit's allowable fuels at their respective maximum heat input ratings, and a maximum operating limit of 500 hours per year. The higher of the emission factors between natural gas and propane was used to determine emission rates.

<u>Step 1: Identify all control technologies</u>

In reviewing the control technology alternatives to control emissions of VOC from the emergency generators, all applicable BACT determinations and permits for diesel-fired internal combustion engines of comparable ratings have been reviewed, as summarized in Table E.4-1 below:

Table E.4-1: Summary of VOC Control Technology Determinations for Emergency Diesel Generators

Facility Name	Location	Data-base	Process Type[1]	Permit Date	Process Description	Controls / Type	Emission Limits/description		Emission Limit g/hp-hr Equivalent[2] (g/hp-hr)	Comments
Marathon Petroleum Co., LLC – Garyville Refinery	Garyville, LA	RBLC	17.11	Dec-06	Diesel Emergency Generators (2) rated at 1341 hp and 671 hp	Use of diesel with a sulfur content of 15 ppmv or less	0.0025	lb/hp-hr	1.13	Permitted for 182 operating hours per yr each
Merck & Company	Westpoint, PA	RBLC	17.11	Feb-07	Diesel-fired Emergency Generator	None Indicated	0.32 0.40	g/bhp-hr tpy	0.32	
ADM Corn Processing - Cedar Rapids	Linn, IA	RBLC	17.11	June-07	Diesel-fired emergency generator rated at 1,500 kW	No specific control technology is specified. Engine is required to meet limits established as BACT (Tier II nonroad). This could require any number of control technologies and operational requirements to meet the BACT standard.	0.3	g/bhp-hr	0.30	Equivalent to Tier II standard per 40 CFR 89.
Minnesota Municipal Power Agency - Fairbault Energy Park	Rice, MN	RBLC	17.11	June-07	No. 2 fuel oil emergency generator rated at 1,750 kW	None Indicated	0.007	lbs/hp-hr (3 hr avg)	3.18	Limited to 10 operating hours per day
Creole Trail LNG Import Terminal	Cameron, LA	RBLC	17.11	Aug-07	Diesel emergency generator nos. 1 & 2 rated at 2,168 hp each	Good combustion practices and good engine design	1.67 0.42	lbs/hr tpy	0.349	Limited to 500 operating hours per year
Tate & Lyle Ingredients Americas, Inc.	Webster, IA	RBLC	17.11	Sept-08	Diesel-fired Emergency Generator rated at 700 kW	None Indicated	0.20 0.080	g/kW-hr tpy	0.149	Equivalent to Tier II standard per 40 CFR 89.
Associated Electric Cooperative, Inc.	Chouteau, OK	RBLC	17.11	Jan-09	Emergency Generator rated at 2200 hp	Good combustion practices	1.55	lbs/hr	0.320	
MGM Mirage	Las Vegas, NV	RBLC	17.11	Nov-09	Two Diesel fired emergency generators each rated at 2206 hp	Turbocharger and Good Combustion Practices	0.003 0.71	lb/hp-hr lb/hr (ea)	1.36	Operating hours restricted to one hour per day and 52 hours per year for each unit

[1] 17.11 = large internal combustion engines (diesel)
[2] Conversions assume 100% efficiency for energy conversion, and 7,000 Btu/hp-hr as stated in AP-42 Chapter 3.3, Table 3.3-1, Footnote A

As a consequence of our review, and the evaluation of other available control technology options, the use of carbon adsorption, recuperative thermal oxidation, catalytic oxidation, biofiltration, and good combustion techniques are the control technologies being evaluated as BACT as noted in Table E.4-2 below.

Table E.4-2: Evaluated Control Options for VOC Emissions – Emergency Generators (EDG1 – EDG4)

Option No.	Control Technology
1	Carbon Adsorption
2	Recuperative Thermal Oxidation
3	Catalytic Oxidation
4	Biofiltration
5	Pollution Prevention/Good Combustion Techniques

Option 1 – Carbon Adsorption

Carbon adsorbers typically employ activated carbon, which has an afinity to adsorb VOCs, along with a beneficially large surface area per unit volume. While variables such as the properties of the individual VOC being absorbed, the gas stream concentration of the VOC, and the gas stream temperature will affect the efficiency of the control process, a VOC-laden gas stream passing over a bed of activated carbon will cause VOC to be adsorbed in the carbon bed. Over time, the adsorptive capacity of the carbon is consumed, as its surface area becomes saturated with adsorbate. When this occurs, the carbon can either be exchanged with fresh carbon, or treated through a regeneration process to release the adsorbate.

The regeneration process typically involves heating the carbon bed via steam injection, then drying and cooling the bed using fan-forced air. The exhaust from the vessel during the regeneration process is passed through a condenser/decanter to recover the VOC. Carbon adsorption has the advantages of being relatively effective on low-concentration gas streams, compatibility with large airflow volumes, and greater energy efficiency in many cases as compared to thermal or catalytic oxidation techniques. The control efficiency of a carbon adsorber, when properly maintained and operated, can be as high as 98%.[24]

Option 2 – Recuperative Thermal Oxidation

Volatile Organic Compounds can be oxidized to carbon dioxide and water at high temperatures (generally 300°F above the autoignition temperature of the VOC with a residence time of 0.5 to 1.0 seconds). Thermal oxidizers can recover heat energy using recuperative or regenerative methods. Regenerative thermal oxidizers can achieve a much higher heat recovery rate than recuperative thermal oxidizers. In the most recent publication of the EPA Air Pollution Control Cost Manual (2002), EPA provides cost correlations for regenerative thermal oxidizers for flue gas flow rates 10,000-100,000

[24] Per US EPA Document EPA 456/F-99-004, Choosing An Adsorption System for VOC: Carbon, Zeolite, or Polymers? May 1999, p. 16

scfm, and recuperative thermal oxidizers for flue gas flow rates 500-50,000 scfm.[25] Based on an approximate flow rate of 6,504 scfm from Emergency Generator Nos. 1 – 4, costs to implement the use of recuperative thermal oxidizer to control VOC emissions have been estimated accordingly.

In a recuperative thermal oxidizer, the exhaust air is preheated by means of a heat exchanger before entering the combustion chamber. The hot exhaust from the combustion chamber is then fed through the other side of the heat exchanger to provide the preheating of intake air. Through this means, up to 70%[26] of the heat energy of the exhaust gas can be recovered, allowing for a reduction in fuel consumption. While this degree of heat recovery is less than is possible using the regenerative mechanism, the capital cost of the recuperative design can be substantially lower, which can, in some cases, offset the additional fuel consumption of the recuperative design. The control efficiency of a Recuperative Thermal Oxidizer, when properly maintained and operated, can be as high as 98%.[25]

Option 3 – Catalytic Oxidation

Catalytic oxidation is a post combustion control technique for reducing emissions of methanol and other VOCs. A catalytic oxidation system is a passive reactor, which consists of a honeycomb grid of metal panels, typically coated with platinum or rhodium. The catalyst grid is placed in the exhaust where the optimum reaction temperature can be maintained (300°F – 900°F). The catalyst serves to increase reaction rates, thereby enabling the oxidation of hydrocarbons at lower reaction temperatures than in conventional thermal oxidizers. When properly operated and maintained, a catalytic oxidizer can achieve a control efficiency as high as 95%.[27]

Option 4 – Biofiltration

Bioreactors use microbes to consume pollutants from a contaminated air stream. Microbes can easily decompose, VOCs into CO_2 and water. The control efficiency of a bioreactor is influenced by temperature, moisture, nutrients, acidity, and microbe population. Microbes can survive at temperatures between 60 to 105°F in a moist, neutral environment (pH=7) and need to be fed a diet of balanced nutrients.

The US EPA identifies three types of bioreactors: the basic biofilter, the biotrickling filter, and the bioscrubber. The basic biofilter consists of a large flat surface covered with bed media, such as peat, bark, coarse soil, or gravel. Air moves through the bed and comes into contact with microbes, which then decompose the pollutants. Basic biofilters have significant disadvantages. The traditional design requires large open areas and provides no continuous liquid flow in which to adjust pH, keep moisture, or add nutrients. In a biotrickling filter, liquid is sprayed onto a plastic media, where a biofilm is formed. As the air passes through the media, pollutants are absorbed into the liquid phase and come into contact with the microbes. The continuous flow of liquid allows the operator to neutralize acid buildup and provide nutrients when required. The plastic bed

[25] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.5.1 Table 2.7
[26] Per US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.2.1
[27] Per vendor experience and US EPA's Air Pollution Control Cost Manual, 6th Edition, January 2002, Section 3.2, Subsection 2.4

can have a void space of up to 95%, which greatly reduces pressure drop across the packing, and the synthetic material is not consumed by the microbes. Bioscrubbers utilize a chemical scrubber and are more similar to chemical-processing equipment than other bioreactors. Discharge effluent is collected in a storage tank which allows additional time for the microbes to consume pollutants. In the US EPA Clean Air Technology Center's (CATC) report, "Using Bioreactors to Control Air Pollution",[28] bioscrubbers were shown to have much greater capital costs and slightly greater annual costs than combustion control devices. Biotrickling filters were therefore chosen as the most feasible form of bioreactor for Emergency Generator Nos. 1 – 4, and are assumed to be 90% efficient in this analysis.[29]

Option 5 – Pollution Prevention / Good Combustion Techniques

Optimization of the design, operation, and maintenance of the emergency generator and combustion system is the primary mechanism available for lowering VOC. This process is often referred to as combustion controls. This involves designing and maintaining the engine to maintain proper air-fuel ratio and ensuring complete combustion in the cylinder via pressure control over fuel injection and good fuel atomization. As a result of the optimum conditions for combustion, VOC emissions can be minimized.

Step 2: Eliminate Technically infeasible options

All of the above control technologies options are technically feasible.

Step 3: Rank remaining control technologies by control effectiveness

Table E.4-3: Ranking of Control Technology – Emergency Generator Nos. 1 – 4
Baseline Emissions = 0.413 tpy VOC for each Emergency Generator

Control Technology Ranking	Option No.	Control Technology	Control Efficiency	VOC Reductions (tpy)
1	1	Carbon Adsorption	98%	0.404
2	2	Recuperative Thermal Oxidation	98%	0.404
3	3	Catalytic Oxidation	95%	0.392
4	4	Biofiltration	90%	0.371
5	5	Pollution Prevention/ Good Combustion Techniques	N/A	N/A

Step 4: Evaluate most effective controls and document results

Table E.4-4 below summarizes the energy, environmental, and economic impacts of all remaining control technologies.

[28] See http://www.epa.gov/ttn/catc/dir1/fbiorect.pdf
[29] Discussion on Biofiltration from EPA Document EPA-456/R-03-003, Using Biorectors to Control Air Pollution. Sept. 2003

Table E.4-4: BACT Control Analysis – Emergency Generator Nos. 1 – 4

						Change in Facility Emissions[2]					
Option No.	Control Technology	Annualized Cost	Cost Effectiveness ($/ton VOC Reduced)	Total Energy Consumed (MMBtu/yr)	Water Usage (MGD)	NO_x (tpy)	**VOC (tpy)**	CO (tpy)	GHG (tpy CO_2e)	SO_2 (tpy)	Total PM[1] (tpy)
1	Carbon Adsorption	$104,820	$259,296	5.22	Nil	Nil	**-0.404**	Nil	+1.24	Nil	Nil
2	Recuperative Thermal Oxidation	$76,433	$189,073	185	0	+0.014	**-0.404**	+0.003	+16.4	Nil	+0.002
3	Catalytic Oxidation	$73,136	$186,630	120	0	+0.009	**-0.392**	+0.002	+11.0	Nil	+0.001
4	Biofiltration	$210,965	$568,257	30.5	Nil	0	**-0.371**	0	+1.05	0	0
5	Good Combustion Techniques	N/A	N/A	N/A	N/A	N/A	**N/A**	N/A	N/A	N/A	N/A

[1]Total PM includes filterables and condensables. All PM assumed to be <2.5 microns.
[2]Collateral emissions detailed in Table E.8-5

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As shown in Table E.4-4, the estimated annualized cost effectiveness exceeds the level at which the installation of add-on pollution control devices can be deemed reasonable. In addition, the resources and energy that would be required to operate the control technologies are not justified based on the resulting environmental and economic impacts.

Step 5: Select BACT

In order to effectively control VOC emissions from the four process emergency generators (Emission Unit ID Nos. EDG1 – EDG4), good combustion techniques and a federally enforceable limit of 500 hours of operation per year are being proposed as BACT, as summarized below.

Table E.4-5: VOC BACT Proposed for Emergency Generator Nos. 1 – 4

Emission Unit ID Nos.	BACT Work Practice
EDG1 – EDG4	Good combustion techniques with a maximum 500 hours of operation per year each.

Table E.5-1 VOC BACT Cost Analysis:
Fixed-bed Carbon Adsober System on Direct-fired Rotary Calciner Nos. 1 – 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Adsorber Vessel Cost	$908,722	Base cost per EPA Cost Manual Section 3.1, Equation 1.27 in 1999 dollars Cost correlations range: 4,000 to 500,000 scfm. Escalation Based on Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated Carbon Adsorber cost = [(M&S Index, 2nd Q 2010)/(M&S Index, 1999) *(Adsorber Cost, 1999 Dollars)]
Straight Duct Cost	$129,373	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) *(Length of ducting)
Elbows Cost	$55,262	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688 * Duct diameter * 12)) * (No. of elbows)
Instrumentation/Controls	$109,336	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.1, Table 1.3 EC = CarAd Cost+ Straight Duct Cost+Elbows Cost
Freight	$54,668	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.1, Table 1.3
Total Purchased Equipment Cost (PEC)	**$1,257,361**	
Direct Installation Costs		
Foundations and Support	$100,589	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Erection and Handling	$176,031	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Electrical	$50,294	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Piping	$25,147	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Insulation	$12,574	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Painting	$12,574	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Direct Installation Costs (DIC)	**$377,208**	
Total Direct Cost (TDC)	**$1,634,570**	**TDC=PEC+DIC**
Indirect Costs		
Engineering	$125,736	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Construction/Field	$62,868	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Contractor Fees	$125,736	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Start-up	$25,147	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Performance Test	$12,574	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Contingencies	$37,721	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Cost of Lost Production	$525,000	Assumes 1-week additional construction time for tie-ins and start-up
Total Indirect Costs (TIC)	**$914,782**	
Total Capital Cost (TCC)	**$2,549,352**	**TCC=TDC+TIC**
Annual Cost		
Operating Labor	$16,110	Based on 3 shifts/day, 8,592 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.1, Table 1.6 Labor Cost = shifts * hours/shift * hourly rate
Supervisory Labor	$2,417	15% of Operator per EPA Cost Manual Section 3.1, Table 1.6
Maintenance Labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.1, Table 1.6 Labor Cost = shifts * hours/shift * hourly rate
Maintenance Materials	$18,068	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.1, Chapter 1.4.1.7
Carbon Replacement Cost	$7	Carbon Cost and Labor Carbon replacement cost based on of EPA Cost Manual Section 3.1, Chapter 1.4.1.4 with $1/lb carbon cost and replacement labor at $0.05/lb carbon replaced. Recovery factor for a 5-year life and a 7% interest. Carbon Replacement Cost = ((Taxes & Freight Factor * Carbon Cost)+Carbon Replacement Cost) * (Carbon requirement * Capital Recovery Factor)
Steam	$169	As determined in Table E.5-1a
System, Cool/Dry Fans	$6,039	
Cooling Water	$17	
Cost of Lost Production	$525,000	Assumes 1 week annual shutdown for maintenance and repair. (facility estimate)
Overhead	$32,797	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.1, Table 1.6
Insurance, administrative	$76,481	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual, Section 3.1, Table 1.6
Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$279,905	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$975,076**	
Total Cost per ton VOC controlled	**$432,692**	Based on 2.30 tpy baseline and 98% control; 2.25 tons removed

Table E.5-1a VOC BACT Energy Cost Analysis: Fixed-bed Carbon Adsober System on Direct-fired Rotary Calciner Nos. 1 – 4 (each)

Fixed-bed Carbon Adsorber Input Parameters

Gas flowrate:	63,000	[acfm]
Inlet gas temperature:	405	[^oF]
Number of Adsorbing Vessels (N_a):	13	[ ]
Number of Desorbing Vessels (N_d):	5	[ ]
Capacity Factor (f):[1]	1.385	[ ]
Carbon Equilibrium Capacity (w_e):[2]	0.67	[lb VOC/lb C]
Working Capacity (w_c):[3]	0.34	[lb VOC/lb C]
Adsorption Time (q_a):[4]	12	[hrs]
Desorption Time (q_d):[4]	4	[hrs]
Carbon Requirement for Continuous System (M_c):[5]	26.04	[lb]
Superficial Bed Velocity (v_b):[6]	65	[fpm]
Carbon Vessel Diameter (D):[7]	9.74	[ft]
Carbon Vessel Length/Height (L):[8]	4.00	[ft]
Carbon Vessel Surface Area (S):[9]	271.58	[ft^2]
Carbon Bed Thickness (t_b):[10]	0.01	[in]
Carbon Bed Pressure Drop ($D p_b$):[11]	0.003	[inH_2O]
Total System Pressure Drop ($D p_s$):[11]	1.00	[inH_2O]

Potential Emissions

Potential VOC Emissions:	2.30	[tpy]
Potential VOC Emissions from Fuel Combustion:[12]	0	[tpy]
Tons VOC Reduced:[13]	2.25	[tpy]

Utility Cost Inputs	Average Unit Cost[14, 15]	Usage		
Steam[16]	10.51 $/klbs	16.1 klbs/yr	$	169.21
System, Cool/Dry Fans[17]	0.056 $/kWh	108,417 kWh/yr	$	6,038.85
Cooling Water[18]	0.30 $/kgal	55.2 kgal/yr	$	16.56

Footnotes

1	The capacity factor was determined from Equation 1.11 of EPA Air Pollution Control Cost Manual (EPA 452/B-02-001) Section 3.1 for continously operated systems.
2	Source: I.I. El-Sharkawy, B.B. Saha, K. Kuwahara, S. Koyama, and K.C., NG, Adsorption Rate Measurements of Activated Carbon Fiber/ Ethanol Pair for Adsorption Cooling System Application, White Paper, Figure 2, Ethanol Uptake on Activated Carbon with Time at Adsorption Temperature. Carbon equilibrium capacity based on 67% by mass at 27 ^oC. Typically, the carbon equilibrium capacity is based on application of the Freundlich isotherm function and partial pressure of the VOC in the gas stream. The Freundlich isotherm constants for ethanol were not available to apply this function.
3	Working capacity is 50% of equilibrium capacity per Section 3.1, Equation 1.15 of EPA 452/B-02-001
4	Time selected based on daily adsorption/desorption cycle.
5	Carbon mass required for each fixed bed determined from Equation 1.14 of EPA 452/B-02-001 Section 3.1 for continuously operating systems.
6	The superficial bed velocity was chosen based on the guidance in Chapter 1.3.1.2 of EPA Air Pollution Control Cost Manual (EPA 452/B-02-001) Section 3.1
7	The vessel diameter was determined from Equation 1.21 of EPA Air Pollution Control Cost Manual (EPA 452/B-02-001) Section 3.1.
8	The vessel length was determined from Equation 1.23 of EPA 452/B-02-001 Section 3.1 plus 2 feet clearance for gas distribution and disengagement.
9	The vessel surface area = (Π) * (Vessel diameter, D) * [(Vessel length, L) + (Vessel diameter, D)/2)] per EPA 452/B-02-001 Section 3.1, Eqn. 1.24
10	Carbon bed thickness determined from Equation 1.22 of EPA 452/B-02-001 Section 3.1 for carbon density of 30 lb/ft ^{3}.
11	Carbon bed and total system pressure drop determined from Equations 1.30 and 1.32 of EPA 452/B-02-001 Section 3.1
12	Potential VOC emissions from fuel combustion (tpy) of natural gas included in the potential emissions limit
13	100 percent capture and 98 percent destruction efficiency considered.
14	Steam cost is per US EPA Cost Manual, 6th Edition, Section 3.1, Eqn 1.28. Steam prices are based on 120% of the fuel cost (natural gas) and assuming 1 MMBtu/1000 lb steam. Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
15	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
16	Steam requirement estimated at 3.5 lb/lb VOC adsorbed per Equation 1.28 of EPA 452/B-02-001 Section 3.1.
17	System and bed cooling/drying fan power requirements determined from Equations 1.32 and 1.33 of EPA 452/B-02-001 Section 3.1 for the calculated system pressure drop. System fan runs 8,592 hours/year. Volumetric flow rate for the bed cooling/drying fan was determined at 100 cfm per pound of carbon with an operating factor of 0.4 for the number of hours of the regeneration cycle needed for cooling/ drying. Average horsepower is converted to kilowatts by multiplying by 0.746 kW/hp.
18	Cooling water requirements determined by multiplying steam requirement by 3.43 per Equation 1.29 and Cooling water cost is per EPA 452/B-02-001 Section 3.1, Chapter 1.4.1.2.

Table E.5-2 VOC BACT Cost Analysis:
Regenerative Thermal Oxidizers (RTO) on Direct-fired Rotary Calciner Nos. 1 – 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Regenerative Thermal Oxidizer (95% heat recovery - escalated)	$922,754	Base cost per EPA Cost Manual Section 3.2, Equation 2.33, in 1999 dollars Cost correlations range: 10,000 to 100,000 scfm Escalation Based on Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010) / (M&S Index,1999) * (220,400 + 11.57 * (Waste gas flow rate))]
Straight Duct Cost	$96,483	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$18,230	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688*Duct diameter * 12)) * (No. of elbows)
Instrumentation	$103,747	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC = RTO Cost+ Straight Duct Cost+Elbows Cost
Freight	$51,873	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Purchased Equipment Cost (PEC)	**$1,193,087**	
Direct Installation Costs		
Foundation and Supports	$82,997	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Handling and Erection	$145,245	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Electrical	$41,499	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Piping	$20,749	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Insulation of Duct Work	$10,375	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Painting	$10,375	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Direct Installation Costs (DIC)	**$311,240**	
Total Direct Cost (TDC)	**$1,504,327**	**TDC=PEC+DIC**
Indirect Costs		
Engineering	$103,747	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Construction and Field Expenses	$51,873	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contractor Fees	$103,747	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Start-up	$20,749	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Performance Test	$10,375	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contingencies	$31,124	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Cost of Lost Production	$525,000	Assumes 1-week additional construction time for tie-ins and start-up
Total Indirect Costs (TIC)	**$846,615**	
Total Capital Cost (TCC)	**$2,350,942**	**TCC+TDC+TIC**
Annual Cost		
Operating labor	$16,110	Based on 3 shifts/day, 8,592 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Supervisory labor	$2,417	15% of Operating cost per EPA Cost Manual, Section 3.2, Table 2.10
Maintenance labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Maintenance materials	$18,068	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Natural gas	$695,111	As determined in Table E.5-2a
Electricity	$14,654	
Cost of Lost Production	$525,000	Assumes 1 week annual shutdown for maintenance and repair.
Overhead	$32,797	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.2, Table 2.10
Insurance, administrative	$70,528	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual Section 3.2, Table 2.10
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$221,912	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$1,614,664**	
Total Cost per ton VOC controlled	**$716,511**	Based on 2.30 tpy baseline and 98% control; 2.25 tons removed

Table E.5-2a VOC BACT Energy Cost Analysis: Regenerative Thermal Oxidizers (RTO) on Direct-fired Rotary Calciner Nos. 1 – 4 (each)

Regenerative Thermal Oxidizer Input Parameters	Gas flowrate:	63,000	[acfm]
	Reference temperature:	77	[^oF]
	Inlet gas temperature:	405	[^oF]
	Gas flowrate:	39,102	[scfm]
	Inlet gas density:[1]	0.046	[lb/acf]
	Primary heat recovery:	0.950	[fraction]
	Waste gas heat content:[2]	0.068	[Btu/lb]
	Waste gas heat capacity:[3]	0.255	[Btu/lb-^oF]
	Combustion temperature:	1,600	[^oF]
	Heat loss:	0.100	[fraction]
	Exit temperature:	465	[^oF]
	Fuel heat of combustion:	23,808	[Btu/lb]
	Fuel density:[4]	0.043	[lb/ft^3]
Regenerative Thermal Oxidizer Design Parameters	Auxiliary Fuel Requirement:[5]	6.59	[lb/min]
	Auxiliary Fuel Requirement:[5]	153.92	[scfm]
	Total Waste Gas Flowrate:	39,256	[scfm]
VOC Concentration and Heat of Combustion (Waste Gas) Calculations		Ethane	
	Potential Emissions:	2.30	[tpy]
	Molecular Weight of VOC:	30.07	[lb/lb-mol]
	Concentration of VOC by Weight:[6]	3	[ppmw]
	Concentration of VOC by Volume:[7]	3	[ppmv]
	Waste Gas O_2 Content:	20.9	[%]
	Lower Explosive Limit (LEL) of VOC:	3	[%]
	LEL of VOC/Air Mixture:	0.010	[%]
	Heat of Combustion of VOC:	22,323	[Btu/lb]
	Heat of Combustion of Waste Gas:[6]	0.068	[Btu/lb]
	Heat of Combustion of Waste Gas:	0.005	[Btu/scf]

Utility Cost Inputs	Average Unit Cost[8,9]	Unit	Hours per Year	
Natural Gas[10]	8.76 $/Mscf	9.2 Mscf/hr	8,592	$ 695,111.16
Electricity[11]	0.056 $/kWh	30.6 kW	8,592	$ 14,653.72

Footnotes	
1	Based on Ideal Gas Equation at waste gas exhaust temperature, assuming waste gas is principally air.
2	Heat of combustion per pound of inlet waste gas developed from heat of combustion of ethane multiplied by the concentration by weight (ppmw) of ethane.
3	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996.
4	Auxiliary fuel is natural gas with heating value assumed at 1,020 Btu/scf.
5	Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).
6	Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (8760 hrs/yr) / (60 min/hr)) * 1,000,000 / (Gas flowrate, acfm) * (Inlet gas density, lb/ft^3).
7	Parts per million concentration by weight to volume conversion from AP-42 Appendix A.
8	Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
9	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
10	Natural Gas Units = (Auxiliary fuel requirement) * (60 min/hr) / (1000 scf/Mscf)
11	Electricity Units = [0.000117 * (Waste gas exhaust flow) * (Total system pressure drop, assumed 4" w.c.) / 0.6]] per EPA 452/B-02-001, Section 3.2, Equation 2.42.

Table E.5-3 VOC BACT Cost Analysis:
Catalytic Oxidizer on Direct-fired Rotary Calciner Nos. 1 – 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Catalytic Oxidizer (70 % heat recovery - escalated)	$682,651	Base cost per EPA Cost Manual Section 3.2, Equation 2.37; in 1999 dollars Cost correlations range: 2,000 to 50,000 scfm Escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010)/(M&S Index,1999) * (1,443 * (Total gas flowrate)$^{0.5527}$)]
Straight Duct Cost	$96,483	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$18,230	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688*Duct diameter * 12)) * (No. of elbows)
Instrumentation	$79,736	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC = CatOx Cost+ Straight Duct Cost+Elbows Cost
Freight	$39,868	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Purchased Equipment Cost (PEC)	**$916,969**	
Direct Installation Costs		
Foundation and Supports	$73,358	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Handling and Erection	$128,376	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Electrical	$36,679	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Piping	$18,339	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Insulation of Duct Work	$9,170	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Painting	$9,170	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Direct Installation Costs (DIC)	**$275,091**	
Total Direct Cost (TDC)	**$1,192,059**	**TDC+PEC+DIC**
Indirect Costs		
Engineering	$91,697	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Construction and Field Expenses	$45,848	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contractor Fees	$91,697	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Start-up	$18,339	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Performance Test	$9,170	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contingencies	$27,509	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Cost of Lost Production	$525,000	Assumes 1-week additional construction time for tie-ins and start-up
Total Indirect Costs (TIC)	**$809,260**	
Total Capital Cost (TCC)	**$2,001,320**	**TCC=TDC+TIC**
Annual Cost		
Operating labor	$16,110	Based on 3 shifts/day, 8,592 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Supervisory labor	$2,417	15% of Operating cost per EPA Cost Manual, Section 3.2, Table 2.10
Maintenance labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Maintenance materials	$18,068	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Natural gas	$573,671	As determined in Table E.5-3a
Electricity	$76,879	
Catalyst Replacement	$36,378	Catalyst replacement costs = (volume of catalyst) * (price of catalyst, $/ft3) * (catalyst capital recovery factor) Catalyst volume is determined in Table E.6-3a Recovery factor at 7% interest rate over 4 years = 0.2952 Catalyst Price = $650/ft^3
Cost of Lost Production	$525,000	Assumes 1 week annual shutdown for maintenance and repair.
Overhead	$32,797	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.2, Table 2.10
Insurance, administrative	$60,040	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual Section 3.2, Table 2.10
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$188,910	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$1,548,336**	
Total Cost per ton VOC controlled	**$708,775**	Based on 2.30 tpy baseline and 95% control; 2.18 tons removed

Table E.5-3a VOC BACT Energy Cost Analysis: Catlytic Oxidizer on Direct-fired Rotary Calciner Nos. 1 – 4 (each)

Catalytic Oxidizer Input Parameters			
	Gas flowrate:	63,000	[acfm]
	Reference temperature:	77	[°F]
	Inlet gas temperature:	405	[°F]
	Gas flowrate:	39,102	[scfm]
	Inlet gas density:[1]	0.046	[lb/acf]
	Primary heat recovery:	0.700	[fraction]
	Waste gas heat content:[2]	0.068	[Btu/lb]
	Waste gas heat capacity:[3]	0.248	[Btu/lb-°F]
	Combustion temperature:	750	[°F]
	Preheat Exit Temperature:	647	[°F]
	Fuel heat of combustion:	23,808	[Btu/lb]
	Fuel density:[4]	0.041	[lb/ft³]
Catalytic Oxidizer Design Parameters	Total Auxiliary Fuel Requirement:[5]	5.18	[lb/min]
	Total Auxiliary Fuel Requirement:[5]	127.03	[scfm]
	Total Gas Flowrate:	39,229	[scfm]
	Total Catalyst Volume:[6]	189.57	[ft³]
VOC Concentration and Heat of Combustion (Waste Gas) Calculations		Ethane	
	Potential Emissions:	2.30	[tpy]
	Molecular Weight of VOC:	30.07	[lb/lb-mol]
	Concentration of VOC by Weight:[7]	3	[ppmw]
	Concentration of VOC by Volume:[8]	3	[ppmv]
	Waste Gas O_2 Content:	20.9	[%]
	Lower Explosive Limit (LEL) of VOC:	3	[%]
	LEL of VOC/Air Mixture:	0.010	[%]
	Heat of Combustion of VOC:	22,323	[Btu/lb]
	Heat of Combustion of Waste Gas:[2]	0.068	[Btu/lb]
	Heat of Combustion of Waste Gas:	0.005	[Btu/scf]

Utility Cost Inputs	Average Unit Cost[9, 10]	Unit	Hours per Year	
Natural Gas[11]	8.76 $/Mscf	7.62 Mscf/hr	8,592	$ 573,670.60
Electricity[12]	0.056 $/kWh	161 kWh/hr	8,592	$ 76,879.31

Footnotes	
1	Based on ideal gas equation at waste gas exhaust temperature assuming waste gas is principally air.
2	Heat of combustion per pound of inlet waste gas developed from heat of combustion of ethane multiplied by the concentration by weight (ppmw) of ethane.
3	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996.
4	Auxiliary fuel is natural gas with heating value assumed at 1,020 Btu/scf.
5	Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).
6	Catalyst volume is determined by the following equation: Φ = (Waste Gas flow rate) / (catalyst volume) Φ = space velocity, h-1 and waste gas flow is specified in cu feet/hour. Φ = 20,000 h-1, per Sec 3.2 Subsection 2.4.3 of the Cost Manual Therefore, catalyst volume = [(waste gas flow rate) * (60 min/hrs) * (460 + inlet temp) / (460 + ref temp)] / 20,000 h-1
7	Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (8760 hrs/yr) / (60 min/hr)) * 1000000 / (Gas flowrate, acfm) * (Inlet gas density, lb/ft³).
8	Parts per million concentration by volume to weight conversion from AP-42 Appendix A.
9	Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
10	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
11	Natural Gas Units = (Auxiliary fuel requirement) * (60 min/hr) * (8,592 hr/year)
12	Electricity Units = [0.000117 * (Waste gas exhaust flow) * (Total system pressure drop, assumed 21" w.c.) / 0.6]] per EPA 452/B-02-001, Section 3.2, Equation 2.42.

Table E.5-4 VOC BACT Cost Analysis:
Biotrickling Filter on Direct-fired Rotary Calciner Nos. 1 – 4 (each)

Cost Element	Budget Ammount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Biofilter	$1,405,000	Source: Using Bioreactors to Control Air Pollution, EPA CATC, Table 6 Escalation Based on Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated Biofilter cost = [(M&S Index, 2nd Q 2010) / (M&S Index, 2000) * (25.1, $/acfm) * (actual gas flow rate, acfm)]
Heat Exchanger	$558,000	Engineering company (Matches Engineering) estimate for a 304 SS U-Tube Shell and Tube heat exchanger in 2007 Dollars (twin 4,303 ft^2 in parallel)
Straight Duct Cost	$100,399	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$20,873	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual Cost of elbows = 74.2 * (e^ (0.0688 * Duct diameter * 12)) * (No. of elbows)
Instrumentation/Controls	$208,427	Cost factor (0.10 * EC) per EPA Cost Manual, Section 5.2 Table 1.3 EC = Biofilter Cost+ Straight Duct Cost+Elbows Cost
Freight	$104,214	Cost factor (0.05 * EC) per EPA Cost Manual, Section 5.2, Table 1.3
Total Purchased Equipment Costs (PEC)	**$2,292,699**	
Direct Installation Costs		Average cost factors for packed tower absorber used as best esimate for biotrickling filter (Section 5.2, Ch. 1)
Foundations and Support	$275,124	Cost factor (0.12 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Erection and Handling	$917,080	Cost factor (0.40 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Electrical	$22,927	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Piping	$687,810	Cost factor (0.30 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Insulation	$22,927	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Painting	$22,927	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Site Preparation costs	$22,927	Site preparation and building costs are assumed to be 10% of purchased equipment costs per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
Direct Installation Cost (DIC)	**$1,971,721**	
Total Direct Costs (TDC)	**$4,264,421**	**TDC=PEC+DIC**
Indirect Costs		
Engineering/Supervision	$239,691	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Construction/Field	$239,691	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Contractor Fees	$239,691	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Start-up	$23,969	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Performance Test	$23,969	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Contingencies	$71,907	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Cost of Lost Production	$525,000	Assumes 1-week additional construction time for tie-ins and start-up
Total Indirect Cost (TIC)	**$1,363,919**	
Total Capital Costs (TCC)	**$5,628,340**	**TCC=TDC+TIC**
Annual Cost		
Operating Labor	$16,110	Based on 3 shifts/day, 8,592 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
Supervisory Labor	$2,417	15% of Operating cost per EPA Cost Manual, Section 5.2, Table 1.4
Maintenance Labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
Maintenance Materials	$112,567	Maintenance materials 2% of the total capital cost per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
Biofilter Media Cost	$77,038	Source: Table 9 of EPA 456-R-03-003 "Using Bioreactors to Control Air Pollution" Escalation Based on Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated Media cost = (M&S Index, 2nd Q 2010) / (M&S Index, 2003) * (1.42, $/acfm) * (actual gas flow rate, acfm)
Electricity (Biofilter)	$51,441	As determined in Table E.5-4a
Water	$1,334	
Cost of Lost Production	$525,000	Assumes 1 week annual shutdown for maintenance and repair.
Overhead	$89,496	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 5.2, Table 1.4
Insurance, administrative	$168,850	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual, Section 5.2, Table 1.4
Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery	$617,961	Total Capital Cost * Capital Recovery Factor
Total Annualized Cost	**$1,680,283**	
Total Cost per ton VOC controlled	**$811,907**	Based on 2.30 tpy baseline and 90% control; 2.07 tons removed

Table E.5-4a VOC BACT Energy Cost Analysis: Biotrickling Filter on Direct-fired Rotary Calciner Nos. 1 – 4 (each)

Biotrickling Filter Input Parameters	Gas flowrate:	63,000	[acfm]
	Reference temperature:	77	[^oF]
	Inlet gas temperature:	405	[^oF]
	Gas flowrate:	39,102	[scfm]
	Inlet gas density:[1]	0.046	[lb/acf]
	Fractional moisture content of inlet gas:	10%	
Shell-and-Tube Heat Exchanger Parameters			
Inlet at 10% moisture, 405 °F:			
	Mass flow rate of water vapor:[2]	182.8	[lb/min]
	Mass flow rate of dry air:[3]	2650.8	[lb/min]
	Total mass flow rate:	2833.6	[lb/min]
	Gas mixing ratio:[4]	0.069	[lb/lb]
	Gas mixing ratio:[4]	483	[gr/lb]
	Enthalpy of gas:[5]	184.9	[Btu/lb]
	Temperature of cool fluid at inlet:	70	[^oF]
Outlet at 100% humidity, 100 ^{o}F:			
	Gas temperature to biofilter:[6]	100	[^oF]
	Enthalpy of gas:[5]	71.8	[Btu/lb]
	Change in enthalpy:	113.1	[Btu/lb]
	Temperature of cool fluid at outlet:	80	[^oF]
	Heat transfer rate:[7]	19.24	[MMBtu/hr]
	Heat transfer coefficient:[8]	20.0	[Btu/ft^2*hr*^oF]
	Log mean temperature difference:[9]	111.8	[^oF]
	Total surface area:[10]	8,605	[ft^2]
	Gas humid volume:[5]	15.09	[ft^3/lb]
	Standard gas flow rate:[11]	40,001	[scfm]
	Actual gas flow rate:	41,715	[acfm]
Potential Emissions			
	Potential VOC Emissions:	2.30	[tpy]
	Tons VOC Reduced with 90% efficiency:[12]	2.07	[tpy]

Utility Cost Inputs	Average Unit Cost[13]	Unit[14, 15]	No. Hours per Year		
Electricity	0.056 $/kWh	107.5 kW	8,592	$	51,440.93
Water	0.30 $/kgal	0.518 kgal/hr	8,592	$	1,334.47

Footnotes	
1	Based on Ideal Gas Equation at waste gas exhaust temperature assuming waste gas is principally air.
2	Mass flow rate of water vapor (lb/min) = (flowrate, scfm)*(moisture content)*(molecular weight/volume of one mole of air)
3	Mass flow rate of air (lb/min) = (flowrate, scfm)*(1-moisture content)*(molecular weight/volume of one mole of air)
4	Mixing ratio = ratio of mass of water vapor to mass of dry air
5	Calculated using psychrometric equations
6	Temperature at which biomass can survive
7	Heat transfer rate, MMBtu/hr = (total mass flow rate, lb/min) * (change in enthalpy, Btu/lb) * (60 min/hr) / (10^6 Btu/MMBtu)
8	Source: Weider, Seader, and Lewin. "Product and Process Design Principles, 2nd edition." p. 431, Table 13.5, "Typical Overall Heat Transfer Coefficients for Shell-and-Tube Heat Exchangers." Shell side water, tube side air (2004)
9	T_{lm}, $^oF = ((T_{h,o}-T_{c,o}) - (T_{h,i}-T_{c,i})) / \ln((T_{h,o} - T_{c,o}) / (T_{h,i}-T_{c,i}))$ where i is inlet, o is outlet, h is hot air, and c is cool fluid
10	Area, ft^2 = (heat transfer rate) / ((Heat transfer coefficient) * (log mean temperature difference))
11	Gas flow rate (scfm) = (heat exchanger outlet gas humid volume, ft^3/lb) * (mass flow rate of air, lb/min)
12	100 percent capture and 90 percent destruction efficiency considered.
13	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
14	Source: Average of power demand specifications from two vendor quotes for biotrickling filters at 24,338 scfm. Electricity Unit = ((65.4 kW) / (24,338 scfm exhaust gas)) * (standard gas flow rate, scfm)
15	Source: Average of water usage specifications from two vendor quotes for biotrickling filters at 24,338 scfm. Water cost =((5.25 gal/min) * (60 min/hr) / (1000 gal/kgal) / (24338 scf/min)) * (standard gas flow rate, scfm) Water cost is per Chapter 1.4.1.2 of EPA Air Pollution Control Cost Manual (EPA 452/B-02-001) Section 3.1 for Carbon Adsorbers (closest available reference for water cost from non-municipal sources).

Table E.5-5: Energy and Environmental Impact Summary for Direct-fired Rotary Calciners Nos. 1 – 4 (each)

	Resource Consumption			Energy Equivalents	
Control Technology	Water (MGD)[1]	Gas (Mscf/yr)[1]	Electricity (kWh/yr)[1]	Total Energy Consumed (MMBtu/yr)[2]	Total Energy Consumed (MMBtu/hr)[3]
Carbon Adsorption	Nil	15.8	108,417	386	0.044
Regenerative Thermal Oxidation	0	79,351	263,083	81,836	9.34
Catalytic Oxidation	0	65,488	1,380,239	71,508	8.16
Biofiltration	0.012	0	923,536	3,152	0.360
Good Combustion Techniques	0	0	0	0	0

	Collateral Emissions							
Control Technology	NO_x (tpy)[4]	GHG (tpy CO_2e)[5]	VOC → GHG (tpy CO_2e)[6]	Total GHG (tpy CO_2e)[7]	CO (tpy)[8]	VOC (tpy)[9]	SO_2 (tpy)[10]	Total PM (tpy)[11,12]
Carbon Adsorption	0.00	0.95	6.46	7.42	0.00	0.00	0.00	0.00
Regenerative Thermal Oxidation	3.97	4,790	6.46	4,796	3.33	0.218	0.024	0.302
Catalytic Oxidation	3.27	3,953	6.07	3,959	2.75	0.180	0.020	0.249
Biofiltration	0.00	0.00	5.45	5.45	0.00	0.00	0.00	0.00
Good Combustion Techniques	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Notes	
1	Per cost-effectiveness calculation sheets. Carbon adsorber utilities include cooling water usage, water and gas used for steam production.
2	Total Energy Consumed, MMBtu/yr = (Gas Consumption, Mscf/yr) / (1,000 Mscf/MMscf) * (1,020 MMBtu/MMscf) + (Electricity Consumption, kWh/year) * (3413 Btu-hr/kWh) / (10^6 Btu/MMBtu
3	Total Energy Consumed, MMBtu/hr = (Total Energy Consumed, MMBtu/yr) / (8,760 hr/yr)
4	Estimated NO_x emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1, NO_x emissions from small uncontrolled boilers. NO_x tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (100 lb NO_x/MMscf) / (2000 lb/ton)
5	Estimated greenhouse gas (GHG) emissions from natural gas combustion in control device calculated using AP-42 emission factors, 5th Edition, Table 1.4-2. Combined GHG Emission Factor, lb CO_2e/MMscf = (120,000 lb CO_2/MMscf) * (CO_2 GWP =1) + (2.2 lb N_2O/MMscf) * (N_2O GWP=310) + (2.3 lb CH_4/MMscf) * (CH_4 GWP=21) GHG Emissions, tpy CO_2e = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (GHG EF=120,730 lb CO_2e/MMscf) / (2000 lb/ton)
6	GHG emissions from VOC destruction = (tons of VOC destroyed) * (2 mol CO_2/1 mol Ethane) * [(44.01 g/mol CO_2) / (30.07 g/mol ethane) * (CC_2 GWP=1)]
7	Sum of GHG emissions from natural gas combustion and VOC destruction.
8	Estimated CO emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1. CO, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (84 lb CO/MMscf) / (2000 lb/ton)
9	Estimated VOC emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. VOC, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (5.5 lb VOC/MMscf) / (2000 lb/ton)
10	Estimated SO_2 emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. SO_2, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (0.6 lb SO_2/MMscf) / (2000 lb/ton)
11	Estimated PM emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. PM, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (7.6 lb PM/MMscf) / (2000 lb/ton)
12	Total PM includes filterables and condensables. All PM assumed to be <2.5 microns

Table E.6-1 VOC BACT Cost Analysis:
Fixed-bed Carbon Adsober System on Spray Dryer Nos. 1 – 8 (per line)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Absorber Vessel Cost	$915,584	Base cost per EPA Cost Manual Section 3.1, Equation 1.27 in 1999 dollars Cost correlations range: 4,000 to 500,000 scfm. Escalation Based on Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated Carbon Adsorber cost = [(M&S Index, 2nd Q 2010)/(M&S Index, 1999) *(Adsorber Cost, 1999 Dollars)]
Straight Duct Cost	$163,298	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) *(Length of ducting)
Elbows Cost	$164,273	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688 * Duct diameter * 12)) * (No. of elbows)
Instrumentation/Controls	$124,315	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.1, Table 1.3 EC = RTO Cost+ Straight Duct Cost+Elbows Cost
Freight	$62,158	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.1, Table 1.3
Total Purchased Equipment Cost (PEC)	**$1,429,628**	
Direct Installation Costs		
Foundations and Support	$114,370	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Erection and Handling	$200,148	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Electrical	$57,185	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Piping	$28,593	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Insulation	$14,296	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Painting	$14,296	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Direct Installation Costs (DIC)	**$428,888**	
Total Direct Cost (TDC)	**$1,858,516**	**TDC=PEC+DIC**
Indirect Costs		
Engineering	$142,963	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Construction/Field	$71,481	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Contractor Fees	$142,963	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Start-up	$28,593	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Performance Test	$14,296	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Contingencies	$42,889	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Total Indirect Costs (TIC)	**$443,185**	
Total Capital Cost (TCC)	**$2,301,700**	**TCC=TDC+TIC**
Annual Cost		
Operating Labor	$16,425	Based on 3 shifts/day, 8,760 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.1, Table 1.6 Labor Cost = shifts * hours/shift * hourly rate
Supervisory Labor	$2,464	15% of Operator per EPA Cost Manual Section 3.1, Table 1.6
Maintenance Labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.1, Table 1.6 Labor Cost = shifts * hours/shift * hourly rate
Maintenance Materials	$18,068	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.1, Table 1.6
Carbon Replacement Cost	$41	Carbon Cost and Labor Carbon replacement cost based on of EPA Cost Manual Section 3.1, Chapter 1.4.1.4 with $1/lb carbon cost and replacement labor at $0.05/lb carbon replaced. Recovery factor for a 5-year life and a 7% interest. Carbon Replacement Cost = ((Taxes & Freight Factor * Carbon Cost)+Carbon Replacement Cost) * (Carbon requirement * Capital Recovery Factor)
Steam	$1,004	As determined in Table E.6-1a
System, Cool/Dry Fans	$10,092	
Cooling Water	$98	
Overhead	$33,014	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.1, Table 1.6
Insurance, administrative	$69,051	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual, Section 3.1, Table 1.6
Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$252,714	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$421,038**	
Total Cost per ton VOC controlled	**$31,498**	Based on 13.64 tpy baseline and 98% control; 13.37 tons removed

Table E.6-1a VOC BACT Energy Cost Analysis: Fixed-bed Carbon Adsober System on Spray Dryer Nos. 1 – 8 (per line)

Fixed-bed Carbon Adsorber Input Parameters			
	Gas flowrate:	92,000	[acfm]
	Inlet gas temperature:	180	[^oF]
	Number of Adsorbing Vessels (N_a):	9	[ ]
	Number of Desorbing Vessels (N_d):	3	[ ]
	Capacity Factor (f):[1]	1.333	[ ]
	Carbon Equilibrium Capacity (w_e):[2]	0.67	[lb VOC/lb C]
	Working Capacity (w_c):[3]	0.34	[lb VOC/lb C]
	Adsorption Time (q_a):[4]	12	[hrs]
	Desorption Time (q_d):[4]	4	[hrs]
	Carbon Requirement for Continuous System (M_c):[5]	148.74	[lb]
	Superficial Bed Velocity (v_b):[6]	65	[fpm]
	Carbon Vessel Diameter (D):[7]	14.15	[ft]
	Carbon Vessel Length/Height (L):[8]	4.00	[ft]
	Carbon Vessel Surface Area (S):[9]	492.51	[ft^2]
	Carbon Bed Thickness (t_b):[10]	0.042	[in]
	Carbon Bed Pressure Drop ($D p_b$):[11]	0.010	[inH_2O]
	Total System Pressure Drop ($D p_s$):[11]	1.01	[inH_2O]
Potential Emissions			
	Potential VOC Emissions:	13.64	[tpy]
	Tons VOC Reduced:[12]	13.37	[tpy]

Utility Cost Inputs	Average Unit Cost[13, 14]	Usage		
Steam[15]	10.51 $/klbs	95 klbs/yr	$	1,003.69
System, Cool/Dry Fans[16]	0.056 $/kWh	181,188 kWh/yr	$	10,092.17
Cooling Water[17]	0.30 $/kgal	327 kgal/yr	$	98.25

Footnotes	
1	The capacity factor was determined from Equation 1.11 of EPA Air Pollution Control Cost Manual (EPA 452/B-02-001) Section 3.1 for continuously operated systems.
2	Source: I.I. El-Sharkawy, B.B. Saha, K. Kuwahara, S. Koyama, and K.C., NG, Adsorption Rate Measurements of Activated Carbon Fiber/ Ethanol Pair for Adsorption Cooling System Application, White Paper, Figure 2, Ethanol Uptake on Activated Carbon with Time at Adsorption Temperature. Carbon equilibrium capacity based on 67% by mass at 27^{o}C. Typically, the carbon equilibrium capacity is based on application of the Freundlich isotherm function and partial pressure of the VOC in the gas stream. The Freundlich isotherm constants for ethanol were not available to apply this function.
3	Working capacity is 50% of equilibrium capacity per Section 3.1, Equation 1.15 of EPA 452/B-02-001
4	Time selected based on daily adsorption/desorption cycle.
5	Carbon mass required for each fixed bed determined from Equation 1.14 of EPA 452/B-02-001 Section 3.1 for continuously operating systems.
6	The superficial bed velocity was chosen based on the guidance in Chapter 1.3.1.2 of EPA Air Pollution Control Cost Manual (EPA 452/B-02-001) Section 3.1
7	Vessel diameter was determined from Equation 1.21 of EPA Air Pollution Control Cost Manual (EPA 452/B-02-001) Section 3.1.
8	The vessel length was determined from Equation 1.23 of EPA 452/B-02-001 Section 3.1 plus 2 feet clearance for gas distribution
8	and disengagement.
9	Vessel surface area = (Π) * (Vessel diameter, D) * [(Vessel length, L) + (Vessel diameter, D)/2)] per EPA 452/B-02-001 Section 3.1, Eqn. 1.24
10	Carbon bed thickness determined from Equation 1.22 of EPA 452/B-02-001 Section 3.1 for carbon density of 30 lb/f^3.
11	Carbon bed and total system pressure drop determined from Equations 1.30 and 1.32 of EPA 452/B-02-001 Section 3.1
12	100 percent capture and 98.5 percent destruction efficiency considered.
13	Steam cost is per US EPA Cost Manual, 6th Edition, Section 3.1, Eqn 1.28. Steam prices are based on 120% of the fuel cost (natural gas) and assuming 1 MMBtu/1000 lb steam. Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
14	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
15	Steam requirement estimated at 3.5 lb/lb VOC adsorbed per Equation 1.28 of EPA 452/B-02-001 Section 3.1.
16	System and bed cooling/drying fan power requirements determined from Equations 1.32 and 1.33 of EPA 452/B-02-001 Section 3.1 for the calculated system pressure drop. System fan runs 8,760 hours/year. Volumetric flow rate for the bed cooling/drying fan was determined at 100 cfm per pound of carbon with an operating factor of 0.4 for the number of hours of the regeneration cycle needed for cooling/drying. Average horsepower is converted to kilowatts by multiplying by 0.746 kW/hp.
17	Cooling water requirements determined by multiplying steam requirement by 3.43 per Equation 1.29 and Cooling water cost is per EPA 452/B-02-001 Section 3.1, Chapter 1.4.1.2.

Table E.6-2 VOC BACT Cost Analysis:
Regeneratrive Thermal Oxidizer (RTO) on Spray Dryer Nos.1 – 8 (per line)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Regenerative Thermal Oxidizer (95% heat recovery - escalated)	$1,528,099	Base cost per EPA Cost Manual Section 3.2, Equation 2.33, in 1999 dollars Cost correlations range: 10,000 to 100,000 scfm Escalation Based on Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010) / (M&S Index,1999) * (220,400 + 11.57 * (Waste gas flow rate))]
Straight Duct Cost	$146,584	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$96,612	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688*Duct diameter * 12)) * (No. of elbows)
Instrumentation	$177,130	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC = RTO Cost+ Straight Duct Cost+Elbows Cost
Freight	$88,565	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Purchased Equipment Cost (PEC)	**$2,036,990**	
Direct Installation Costs		
Foundation and Supports	$162,959	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Handling and Erection	$285,179	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Electrical	$81,480	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Piping	$40,740	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Insulation of Duct Work	$20,370	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Painting	$20,370	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Direct Installation Costs (DIC)	**$611,097**	
Total Direct Cost (TDC)	**$2,648,087**	**TDC=PEC+DIC**
Indirect Costs		
Engineering	$203,699	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Construction and Field Expenses	$101,849	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contractor Fees	$203,699	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Start-up	$40,740	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Performance Test	$20,370	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contingencies	$61,110	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Indirect Costs (TIC)	**$631,467**	
Total Capital Cost (TCC)	**$3,279,554**	**TCC=TDC+TIC**
Annual Cost		
Operating labor	$16,425	Based on 3 shifts/day, 8,760 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Supervisory labor	$2,464	15% of Operating cost per EPA Cost Manual, Section 3.2, Table 2.10
Maintenance labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Maintenance materials	$18,068	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Natural gas	$1,468,871	As determined in Table E.6-2a
Electricity	$29,497	
Overhead	$33,014	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.2, Table 2.10
Insurance, administrative	$98,387	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual Section 3.2, Table 2.10
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$309,567	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$1,994,360**	
Total Cost per ton VOC controlled	**$149,198**	Based on 13.64 tpy baseline and 98% control; 13.37 tons removed

Table E.6-2a VOC BACT Energy Cost Analysis: Regenerative Thermal Oxidizers (RTO) on Spray Dryer Nos. 1 – 8 (per line)

Regenerative Thermal Oxidizer Input Parameters

Gas flowrate:	92,000	[acfm]
Reference temperature:	77	[^oF]
Inlet gas temperature:	180	[^oF]
Gas flowrate:	77,186	[scfm]
Inlet gas density:[1]	0.062	[lb/acf]
Primary heat recovery:	0.950	[fraction]
Waste gas heat content:[2]	0.099	[Btu/lb]
Waste gas heat capacity:[3]	0.255	[Btu/lb-^oF]
Combustion temperature:	1,600	[^oF]
Heat loss:	0.100	[fraction]
Exit temperature:	251	[^oF]
Fuel heat of combustion:	23,808	[Btu/lb]
Fuel density:[4]	0.043	[lb/ft^3]

Regenerative Thermal Oxidizer Design Parameters

Auxiliary Fuel Requirement:[5]	13.67	[lb/min]
Auxiliary Fuel Requirement:[5]	319.02	[scfm]
Total Waste Gas Flowrate:	77,505	[scfm]

VOC Concentration and Heat of Combustion (Waste Gas) Calculations

	Ethane	
Potential Emissions:	13.64	[tpy]
Molecular Weight of VOC:	30.07	[lb/lb-mol]
Concentration of VOC by Weight:[6]	9.10	[ppmw]
Concentration of VOC by Volume:[7]	8.77	[ppmv]
Waste Gas O_2 Content:	20.9	[%]
Lower Explosive Limit (LEL) of VOC:	3	[%]
LEL of VOC/Air Mixture:	0.029	[%]
Heat of Combustion of VOC:	10,919	[Btu/lb]
Heat of Combustion of Waste Gas:[2]	0.099	[Btu/lb]
Heat of Combustion of Waste Gas:	0.007	[Btu/scf]

Utility Cost Inputs	Average Unit Cost[8,9]	Unit	Hours per Year	
Natural Gas[10]	8.76 $/Mscf	19.1 Mscf/hr	8,760	$ 1,468,871.49
Electricity[11]	0.056 $/kWh	60.5 kW	8,760	$ 29,497.44

Footnotes	
1	Based on Ideal Gas Equation at waste gas exhaust temperature, assuming waste gas is principally air.
2	Heat of combustion per pound of inlet waste gas developed from heat of combustion of VOC multiplied by the concentration by weight (ppmw) of that VOC.
3	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996.
4	Auxiliary fuel is natural gas with heating value assumed at 1,020 Btu/scf.
5	Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).
6	Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (8760 hrs/yr) / (60 min/hr)) * 1000000 / (Gas flowrate, acfm) * (Inlet gas density, lb/ft^3)
7	Parts per million concentration by weight to volume conversion from AP-42 Appendix A.
8	Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
9	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
10	Natural Gas Units = (Auxiliary fuel requirement) * (60 min/hr) / (1000 scf/Mscf)
11	Electricity Units = [0.000117 * (Waste gas exhaust flow) * (Total system pressure drop, assumed 4 w.c.) / 0.6]] per EPA 452/B-02-001, Section 3.2, Equation 2.42.

Table E.6-3 VOC BACT Cost Analysis: Catalytic Oxidizer on Spray Dryer Nos. 1 – 8 (per line)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Catalytic Oxidizer (70 % heat recovery - escalated)	$994,811	Base cost per EPA Cost Manual Section 3.2, Equation 2.37; in 1999 dollars Cost correlations range: 2,000 to 50,000 scfm Escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010)/(M&S Index,1999) * (1,443 * (Total gas flowrate)$^{0.5527}$)]
Straight Duct Cost	$146,584	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$96,612	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688*Duct diameter * 12)) * (No. of elbows)
Purchased Equipment Cost (EC)	$1,238,007	Total Capture System + Total RTO Costs
Instrumentation	$123,801	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC = RTO Cost+ Straight Duct Cost+Elbows Cost
Freight	$61,900	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Purchased Equipment Cost (PEC)	**$2,661,716**	
Direct Installation Costs (DIC)		
Foundation and Supports	$212,937	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Handling and Erection	$372,640	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Electrical	$106,469	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Piping	$53,234	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Insulation of Duct Work	$26,617	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Painting	$26,617	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Direct Installation Costs (DIC)	**$798,515**	
Total Direct Cost (TDC)	**$3,460,231**	**TDC=PEC+DIC**
Indirect Costs		
Engineering	$266,172	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Construction and Field Expenses	$133,086	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contractor Fees	$266,172	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Start-up	$53,234	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Performance Test	$26,617	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contingencies	$79,851	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Indirect Costs (TIC)	**$825,132**	
Total Capital Cost (TCC)	**$4,285,362**	**TCC=TDC+TIC**
Annual Cost		
Operating labor	$16,425	Based on 3 shifts/day, 8,760 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Supervisory labor	$2,464	15% of Operating cost per EPA Cost Manual, Section 3.2, Table 2.10
Maintenance labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Maintenance materials	$18,068	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Natural gas	$1,610,478	As determined in Table E.6-3a
Electricity	$154,923	
Catalyst Replacement	$53,199	Catalyst replacement costs = (volume of catalyst) * (price of catalyst, $/ft3) * (catalyst capital recovery factor) Catalyst volume is determined in Table E.6-3a Recovery factor at 7% interest rate over 4 years = 0.2952 Catalyst Price = $650/ft^3
Overhead	$33,014	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.2, Table 2.10
Insurance, administrative	$128,561	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost Per EPA Cost Manual Section 3.2, Table 2.10
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$404,508	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$2,439,706**	
Total Cost per ton VOC controlled	**$188,278**	Based on 13.64 tpy baseline and 95% control; 12.96 tons removed

Table E.6-3a VOC BACT Energy Cost Analysis: Catalytic Oxidizer on Spray Dryer Nos. 1 – 8 (per line)

Catalytic Oxidizer Input Parameters	Gas flowrate:	92,000	[acfm]
	Reference temperature:	77	[°F]
	Inlet gas temperature:	180	[°F]
	Gas flowrate:	77,186	[scfm]
	Inlet gas density:[1]	0.062	[lb/acf]
	Primary heat recovery:	0.700	[fraction]
	Waste gas heat content:[2]	0.099	[Btu/lb]
	Waste gas heat capacity:[3]	0.248	[Btu/lb-°F]
	Combustion temperature:	750	[°F]
	Preheat Exit Temperature:	579	[°F]
	Fuel heat of combustion:	23,808	[Btu/lb]
	Fuel density:[4]	0.041	[lb/ft^3]
Catalytic Oxidizer Design Parameters	Total Auxiliary Fuel Requirement:[5]	14.27	[lb/min]
	Total Auxiliary Fuel Requirement:[5]	349.78	[scfm]
	Total Gas Flowrate:	77,536	[scfm]
	Total Catalyst Volume:[6]	277.22	[ft^3]
VOC Concentration and Heat of Combustion (Waste Gas) Calculations		Ethane	
	Potential Emissions:	13.64	[tpy]
	Molecular Weight of VOC:	30.07	[lb/lb-mol]
	Concentration of VOC by Weight:[7]	9.10	[ppmw]
	Concentration of VOC by Volume:[8]	8.77	[ppmv]
	Waste Gas O_2 Content:	20.9	[%]
	Lower Explosive Limit (LEL) of VOC:	3	[%]
	LEL of VOC/Air Mixture:	0.029	[%]
	Heat of Combustion of VOC:	10,919	[Btu/lb]
	Heat of Combustion of Waste Gas:[2]	0.099	[Btu/lb]
	Heat of Combustion of Waste Gas:	0.007	[Btu/scf]

Utility Cost Inputs	Average Unit Cost[9, 10]	Unit	Hours per Year	
Natural Gas[11]	8.76 $/Mscf	21.0 Mscf/hr	8,760	$ 1,610,477.98
Electricity[12]	0.056 $/kWh	318 kWh/hr	8,760	$ 154,923.03

Footnotes	
1	Based on ideal gas equation at waste gas exhaust temperature assuming waste gas is principally air.
2	Heat of combustion per pound of inlet waste gas developed from heat of combustion of ethane multiplied by the concentration by weight (ppmw) of ethane.
3	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996
4	Auxiliary fuel is natural gas with heating value assumed at 1,020 Btu/scf.
5	Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).
6	Catalyst volume is determined by the following equation: Φ = (Waste Gas flow rate) / (catalyst volume) Φ = space velocity, h-1 and waste gas flow is specified in cu feet/hour. Φ = 20,000 h-1, per Sec 3.2 Subsection 2.4.3 of the Cost Manual Therefore, catalyst volume = [(waste gas flow rate) * (60 min/hrs) * (460 + inlet temp) / (460 + ref temp)] / 20,000 h-1
7	Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (8760 hrs/yr) / (60 min/hr)) * 1000000 / (Gas flowrate, acfm) * (Inlet gas density, lb/f^3).
8	Parts per million concentration by volume to weight conversion from AP-42 Appendix A.
9	Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
10	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
11	Natural Gas Units = (Auxiliary fuel requirement) * (60 min/hr)
12	Electricity Units = [0.000117 * (Waste gas exhaust flow) * (Total system pressure drop, assumed 21" w.c.) / 0.6]] per EPA 452/B-02-001, Section 3.2, Equation 2.42.

Table E.6-4 VOC BACT Cost Analysis:
Biotrickling Filter on Spray Dryer Nos. 1 – 8 (per line)

	Cost Element	Budget Ammount	Comments
Capital Cost			
Direct Costs			
	Purchased Equipment Costs (PEC)		
	Biofilter	$2,773,436	Source: Using Bioreactors to Control Air Pollution, EPA CATC, Table 6 Escalation Based on Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated Biofilter cost = [(M&S Index, 2nd Q 2010) / (M&S Index, 2000) * (25.1, $/acfm) * (actual gas flow rate, acfm)]
	Heat Exchanger	$533,200	Engineering company (Matches Engineering) estimate for a 304 SS U-Tube Shell and Tube heat exchanger in 2007 Dollars (twin 4,303 ft^2 in parallel)
	Straight Duct Cost	$152,533	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
	Elbows Cost	$116,849	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^ (0.0688 * Duct diameter * 12)) * (No. of elbows)
	Instrumentation/Controls	$357,602	Cost factor (0.10 * EC) per EPA Cost Manual, Section 5.2, Table 1.3 EC = RTO Cost+ Straight Duct Cost+Elbows Cost
	Freight	$178,801	Cost factor (0.05 * EC) per EPA Cost Manual, Section 5.2, Table 1.3
	Total Purchase Equipment Cost (PEC)	**$4,112,421**	
	Direct Installation Costs (DIC)		Average cost factors for packed tower absorber used as best esimate for biotrickling filter (EPA Cost Manual Section 5.2, Ch. 1) where noted
	Foundations and Support	$493,491	Cost factor (0.12 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
	Erection and Handling	$1,644,968	Cost factor (0.40 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
	Electrical	$41,124	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
	Piping	$1,233,726	Cost factor (0.30 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
	Insulation	$41,124	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
	Painting	$41,124	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
	Site Preparation costs	$411,242	Site preparation and building costs are assumed to be 10% of purchased equipment costs per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
	Direct Installation Cost (DIC)	**$3,906,800**	
	Total Direct Costs (TDC)	**$8,019,221**	**TDC=PEC+DIC**
Indirect Cost			
	Engineering/Supervision	$411,242	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
	Construction/Field	$411,242	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
	Contractor Fees	$411,242	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
	Start-up	$41,124	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
	Performance Test	$41,124	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
	Contingencies	$123,373	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
	Total Indirect Cost (TIC)	**$1,439,347**	
Total Capital Costs (TCC)		**$9,458,569**	**TCC=TDC+TIC**
Annual Cost			
	Operating Labor	$16,425	Based on 3 shifts/day, 8,760 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
	Supervisory Labor	$2,464	15% of Operating cost per EPA Cost Manual, Section 5.2, Table 1.4
	Maintenance Labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
	Maintenance Materials	$189,171	Maintenance materials 2% of the total capital cost per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
	Biofilter Media Cost	$152,072	Source: Table 9 of EPA 456-R-03-003 "Using Bioreactors to Control Air Pollution" Escalation Based on Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated Media cost = (M&S Index, 2nd Q 2010) / (M&S Index, 2003) * (1.42, $/acfm) * (actua gas flow rate, acfm)
	Electricity (Biofilter)	$103,529	As determined in Table E.6-4a
	Water	$2,686	
	Overhead	$135,677	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 5.2, Table 1.4
	Insurance, administrative	$283,757	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost pe EPA Cost Manual, Section 5.2, Table 1.4
	Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
	Capital Recovery	$1,038,500	Total Capital Cost * Capital Recovery Factor
Total Annualized Cost		**$1,825,419**	
Total Cost per ton VOC controlled		**$148,698**	Based on 13.64 tpy baseline and 90% control; 12.28 tons removed

Table E.6-4a VOC BACT Energy Cost Analysis: Biotrickling Filter on Spray Dryer Nos. 1 – 8 (per line)

Biotrickling Filter Input Parameters	Gas flowrate:	92,000	[acfm]
	Reference temperature:	77	[°F]
	Inlet gas temperature:	180	[°F]
	Gas flowrate:	77,186	[scfm]
	Inlet gas density:[1]	0.062	[lb/acf]
	Fractional moisture content of inlet gas:	10%	
Shell-and-Tube Heat Exchanger Parameters			
Inlet at 10% moisture, 180 °F:			
	Mass flow rate of water vapor:[2]	360.9	[lb/min]
	Mass flow rate of dry air:[3]	5232.6	[lb/min]
	Total mass flow rate:	5593.5	[lb/min]
	Gas mixing ratio:[4]	0.069	[lb/lb]
	Gas mixing ratio:[4]	483	[gr/lb]
	Enthalpy of gas:[5]	122.0	[Btu/lb]
	Temperature of cool fluid at inlet:	70	[°F]
Outlet at 100% humidity, 100 °F:			
	Gas temperature to biofilter:[6]	100	[°F]
	Enthalpy of gas:[5]	71.8	[Btu/lb]
	Change in enthalpy:	50.2	[Btu/lb]
	Temperature of cool fluid at outlet:	80	[°F]
	Heat transfer rate:[7]	16.86	[MMBtu/hr]
	Heat transfer coefficient:[8]	20.0	[Btu/ft^2*hr*°F]
	Log mean temperature difference:[9]	52.8	[°F]
	Total surface area:[10]	15,969	[ft^2]
	Gas humid volume:[5]	15.09	[ft^3/lb]
	Standard gas flow rate:[11]	78,960	[scfm]
	Actual gas flow rate:	82,344	[acfm]
Potential Emissions			
	Potential VOC Emissions:	13.64	[tpy]
	Tons VOC Reduced with 90% efficiency:[12]	12.28	[tpy]

Utility Cost Inputs	Average Unit Cost[13]	Unit[14, 15]	No. Hours per Year		
Electricity	0.056 $/kWh	212.2 kW	8,760	$	103,528.60
Water	0.30 $/kgal	1.0 kgal/hr	8,760	$	2,685.71

Footnotes	
1	Based on Ideal Gas Equation at waste gas exhaust temperature assuming waste gas is principally air.
2	Mass flow rate of water vapor (lb/min) = (flowrate, scfm)*(moisture content)*(molecular weight/volume of one mole of air)
3	Mass flow rate of air (lb/min) = (flowrate, scfm)*(1-moisture content)*(molecular weight/volume of one mole of air)
4	Mixing ratio = ratio of mass of water vapor to mass of dry air
5	Calculated using psychrometric equations
6	Temperature at which biomass can survive
7	Heat transfer rate, MMBtu/hr = (total mass flow rate, lb/min) * (change in enthalpy, Btu/lb) * (60 min/hr) / (10^6 Btu/MMBtu)
8	Source: Weider, Seader, and Lewin. "Product and Process Design Principles, 2nd edition." p. 431, Table 13.5, "Typical Overall Heat Transfer Coefficients for Shell-and-Tube Heat Exchangers." Shell side water, tube side air (2004)
9	T_{lm}, °F = (($T_{h,o}$-$T_{c,o}$) - ($T_{h,i}$-$T_{c,i}$)) / ln(($T_{h,o}$ - $T_{c,o}$) / ($T_{h,i}$-$T_{c,i}$)) where i is inlet, o is outlet, h is hot air, and c is cool fluid
10	Area, ft^2 = (heat transfer rate) / ((Heat transfer coefficient) * (log mean temperature difference))
11	Gas flow rate (scfm) = (heat exchanger outlet gas humid volume, ft^3/lb) * (mass flow rate of air, lb/min)
12	100 percent capture and 90 percent destruction efficiency considered.
13	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
14	Source: Average of power demand specifications from two vendor quotes for biotrickling filters at 24,338 scfm. Electricity Unit = ((65.4 kW) / (24,338 scfm exhaust gas)) * (standard gas flow rate, scfm)
15	Source: Average of water usage specifications from two vendor quotes for biotrickling filters at 24,338 scfm. Water cost =((5.25 gal/min) * (60 min/hr) / (1000 gal/kgal) / (24338 scf/min)) * (standard gas flow rate, scfm) Water cost is per Chapter 1.4.1.2 of EPA Air Pollution Control Cost Manual (EPA 452/B-02-001) Section 3.1 for Carbon Adsorbers (closest available reference for water cost from non-municipal sources).

Table E.6-5: Energy and Environmental Impact Summary for Spray Dryer Nos. 1 – 8 (per line)

	Resource Consumption			Energy Equivalents	
Control Technology	Water (MGD)[1]	Gas (Mscf/yr)[1]	Electricity (kWh/yr)[1]	Total Energy Consumed (MMBtu/yr)[2]	Total Energy Consumed (MMBtu/hr)[3]
Carbon Adsorber	Nil	93.6	181,188	714	0.081
Regenerative Thermal Oxidation	0	167,679	529,577	172,840	19.7
Catalytic Oxidation	0	183,845	2,781,383	197,014	22.5
Biofiltration	0.025	0	1,858,682	6,344	0.724
Good Combustion Techniques	0	0	0	0	0

	Collateral Emissions							
Control Technology	NO_x (tpy)[4]	GHG (tpy CO_2e)[5]	VOC → GHG (tpy CO_2e)[6]	Total GHG (tpy CO_2e)[7]	CO (tpy)[8]	VOC (tpy)[9]	SO_2 (tpy)[10]	Total PM (tpy)[11,12]
Carbon Adsorber	Nil	5.65	38.5	44.1	Nil	Nil	Nil	Nil
Regenerative Thermal Oxidation	8.38	10,122	38.3	10,160	7.04	0.461	0.050	0.637
Catalytic Oxidation	9.19	11,098	36.0	11,134	7.72	0.506	0.055	0.699
Biofiltration	0.00	0.00	32.3	32.3	0.00	0.00	0.00	0.00
Good Combustion Techniques	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Notes	
1	Per cost-effectiveness calculation sheets. Carbon adsorber utilities include cooling water usage, water and gas used for steam production.
2	Total Energy Consumed, MMBtu/yr = (Gas Consumption, Mscf/yr) / (1,000 Mscf/MMscf) * (1,020 MMBtu/MMscf) + (Electricity Consumption, kWh/year) * (3413 Btu-hr/kWh) / (10^6 Btu/MMBtu)
3	Total Energy Consumed, MMBtu/hr = (Total Energy Consumed, MMBtu/yr) / (8,760 hr/yr)
4	Estimated NO_x emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1, NO_x emissions from small uncontrolled boilers. NO_x tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (100 lb NO_x/MMscf) / (2000 lb/ton)
5	Estimated greenhouse gas (GHG) emissions from natural gas combustion in control device calculated using AP-42 emission factors, 5th Edition, Table 1.4-2. Combined GHG Emission Factor, lb CO_2e/MMscf = (120,000 lb CO_2/MMscf) * (CO_2 GWP =1) + (2.2 lb N_2O/MMscf) * (N_2O GWP=310) + (2.3 lb CH_4/MMscf) * (CH_4 GWP=21) GHG Emissions, tpy CO_2e = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (GHG EF=120,730 lb CO_2e/MMscf) / (2000 lb/ton)
6	GHG emissions from VOC destruction = (tons of VOC destroyed) * (2 mol CO_2/1 mol Ethane) * [(44.01 g/mol CO_2) / (30.07 g/mol ethane) * (CO_2 GWP=1)]
7	Sum of GHG emissions from natural gas combustion and VOC destruction.
8	Estimated CO emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1. CO, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (84 lb CO/MMscf) / (2000 lb/ton)
9	Estimated VOC emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. VOC, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (5.5 lb VOC/MMscf) / (2000 lb/ton)
10	Estimated SO_2 emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. SO_2, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (0.6 lb SO_2/MMscf) / (2000 lb/ton)
11	Estimated PM emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. PM, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (7.6 lb PM/MMscf) / (2000 lb/ton)
12	Total PM includes filterables and condensables. All PM assumed to be <2.5

Table E.7-1 VOC BACT Cost Analysis:
Canister-Type Carbon Adsober System on Boiler Nos. 1 – 4 (each)

Cost Element	Budget Ammount	Comments
Capital Cost		
Direct Costs		
Waste Gas Capture System Costs (WGCSC)		
Straight Duct Cost	$17,782	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$841	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688 * Duct diameter * 12)) * (No. of elbows)
Waste Gas Capture System Costs (WGCSC)	**$18,623**	
Instrumentation/Controls	$1,862	Cost factor (0.10 * WGCSC) per EPA Cost Manual, Section 3.1, Table 1.3
Freight	$931	Cost factor (0.05 * WGCSC) per EPA Cost Manual, Section 3.1, Table 1.3
Total Direct Cost	**$21,416**	
Total Capital Cost	**$21,416**	
Annual Cost		
Carbon Canisters	$17,550	Based on Amount of carbon calculated in Table E.7-1a at a price of Base cost in 1999 dollars
Maintenance Labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.1, Table 1.6
Total Annual Cost	**$35,618**	
Total Cost per ton VOC controlled	**$96,918**	Based on 0.375 tpy baseline and 98% control; 0.368 tons removed

Table E.7-1a VOC BACT Energy Cost Analysis:
Canister Carbon Adsober System on Boiler Nos. 1 – 4 (each)

Canister Carbon Adsorber Input Parameters			
	Gas flowrate:	2,500	[acfm]
	Inlet gas temperature:	380	[^oF]
	Capacity Factor (f):[1]	2.000	[ ]
	Carbon Equilibrium Capacity (w_e):[2]	0.67	[lb VOC/lb C]
	Working Capacity (w_c):[3]	0.34	[lb VOC/lb C]
	Annual Adsorption Time:[4]	8,760	[hrs]
	Annual Carbon Requirement:	4,477.61	[lb]
	Number of Canisters Required/Year:[5]	30.00	

Potential Emissions			
	Potential VOC Emissions:	0.375	[tpy]
	Tons VOC Reduced:[4]	0.369	[tpy]

Footnotes	
1	The capacity factor was determined from Equation 1.11 of EPA Air Pollution Control Cost Manual (EPA 452/B-02-001) Section 3.1 for continously operated systems.
2	Source: I.I. El-Sharkawy, B.B. Saha, K. Kuwahara, S. Koyama, and K.C., NG, Adsorption Rate Measurements of Activated Carbon Fiber/ Ethanol Pair for Adsorption Cooling System Application, White Paper, Figure 2, Ethanol Uptake on Activated Carbon with Time at Adsorption Temperature. Carbon equilibrium capacity based on 67% by mass at 27^{o}C. Typically, the carbon equilibrium capacity is based on application of the Freundlich isotherm function and partial pressure of the VOC in the gas stream. The Freundlich isotherm constants for ethanol were not available to apply this function.
3	Working capacity is 50% of equilibrium capacity per Section 3.1, Equation 1.15 of EPA 452/B-02-001
4	100 percent capture and 98 percent destruction efficiency considered.
5	Number of Canisters = Annual Carbon Requirement * 150 lbs/canister

Table E.7-2 VOC BACT Cost Analysis: Recuperative Thermal Oxidizer on Boiler Nos. 1 – 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Recuperative Thermal Oxidizer (70% heat recovery - escalated)	$185,015	Base cost per EPA Cost Manual Section 3.2, Equation 2.32; in 1999 dollars Cost correlations range: 500 to 50,000 scfm Escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010) / (M&S Index,1999) * (21,342 + (Waste gas flowrate)$^{0.25}$)]
Straight Duct Cost	$13,502.9	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$682.3	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688*Duct diameter * 12)) * (No. of elbows)
Instrumentation	$19,920	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC = RTO Cost+ Straight Duct Cost+Elbows Cost
Freight	$9,960	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Purchased Equipment Cost	**$229,081**	
Direct Installation Costs		
Foundation and Supports	$18,326	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Handling and Erection	$32,071	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Electrical	$9,163	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Piping	$4,582	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Insulation of Duct Work	$2,291	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Painting	$2,291	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Direct Installation Costs (DIC)	**$68,724**	
Total Direct Cost (TDC)	**$297,805**	**TDC=PEC+DIC**
Indirect Costs		
Engineering	$22,908	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Construction and Field Expenses	$11,454	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contractor Fees	$22,908	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Start-up	$4,582	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Performance Test	$2,291	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contingencies	$6,872	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Indirect Costs (TIC)	**$71,015**	
Total Capital Cost (TCC)	**$368,820**	**TCC=TDC+TIC**
Annual Cost		
Operating labor	$16,425	Based on 3 shifts/day, 8,760 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Supervisory labor	$2,463.8	15% of Operating cost per EPA Cost Manual, Section 3.2, Table 2.10
Maintenance labor	$18,067.5	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Maintenance materials	$18,067.5	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Natural gas	$70,944	As determined in Table E.7-2a
Electricity	$614.0	
Overhead	$33,014	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.2, Table 2.10
Insurance, administrative	$11,065	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual Section 3.2, Table 2.10
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$34,814	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$205,475**	
Total Cost per ton VOC Reduced	**$559,115**	Based on 0.375 tpy baseline and 98% control; 0.368 tons removed

Table E.7-2a VOC BACT Energy Cost Analysis: Recuperative Thermal Oxidizers on Boiler Nos. 1 – 4 (each)

Regenerative Thermal Oxidizer Input Parameters

Gas flowrate:	2,500	[acfm]
Reference temperature:	77	[°F]
Inlet gas temperature:	380	[°F]
Gas flowrate:	1,598	[scfm]
Inlet gas density:[1]	0.047	[lb/acf]
Primary heat recovery:	0.700	[fraction]
Waste gas heat content:[2]	0.270	[Btu/lb]
Waste gas heat capacity:[3]	0.255	[Btu/lb-°F]
Combustion temperature:	1,600	[°F]
Heat loss:	0.100	[fraction]
Exit temperature:	746	[°F]
Fuel heat of combustion:	23,808	[Btu/lb]
Fuel density:[4]	0.043	[lb/ft^3]

Regenerative Thermal Oxidizer Design Parameters

Auxiliary Fuel Requirement:[5]	0.66	[lb/min]
Auxiliary Fuel Requirement:[5]	15.41	[scfm]
Total Waste Gas Flowrate:	1,613	[scfm]

VOC Concentration and Heat of Combustion (Waste Gas) Calculations

	Ethane	
Potential Emissions:	0.375	[tpy]
Molecular Weight:	30.07	[lb/lb-mol]
Concentration of VOC by Weight:[6]	12.1	[ppmw]
Concentration of VOC by Volume:[7]	11.6	[ppmv]
Waste Gas O_2 Content:	20.9	[%]
Lower Explosive Limit (LEL) of VOC:	3	[%]
LEL of VOC/Air Mixture:	0.039	[%]
Heat of Combustion of VOC:	22,323	[Btu/lb]
Heat of Combustion of Waste Gas:[6]	0.270	[Btu/lb]
Heat of Combustion of Waste Gas:	0.020	[Btu/scf]

Utility Cost Inputs	Average Unit Cost[8,9]	Unit	Hours Per Year	
Natural Gas[10]	8.76 $/Mscf	0.925 Mscf/hr	8,760	$ 70,944.25
Electricity[11]	0.056 $/kWh	1.26 kW	8,760	$ 613.99

Footnotes	
1	Based on Ideal Gas Equation at waste gas exhaust temperature, assuming waste gas is principally air.
2	Heat of combustion per pound of inlet waste gas developed from heat of combustion of ethane multiplied by the concentration by weight (ppmw) of ethane.
3	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996.
4	Auxiliary fuel is natural gas with heating value assumed at 1,020 Btu/scf.
5	Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).
6	Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (8760 hrs/yr) / (60 min/hr)) * 1000000 / (Gas flowrate, acfm) * (Inlet gas density, lb/ft^3).
7	Parts per million concentration by weight to volume conversion from AP-42 Appendix A.
8	Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
9	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
10	Natural Gas Units = (Auxiliary fuel requirement) * (60 min/hr)
11	Electricity Units = [0.000117 * (Waste gas exhaust flow) * (Total system pressure drop, assumed 4 w.c.) / 0.6]] per EPA 452/B-02-001, Section 3.2, Equation 2.42.

Table E.7-3 VOC BACT Cost Analysis: Catalytic Oxidizer on Boiler Nos. 1 – 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Catalytic Oxidizer (70 % heat recovery - escalated)	$116,605	Base cost per EPA Cost Manual Section 3.2, Equation 2.37; in 1999 dollars Cost correlations range: 2,000 to 50,000 scfm Escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010)/(M&S Index,1999) * (1,443 * (Total gas flowrate)$^{0.5527}$)]
Straight Duct Cost	$13,503	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$682	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688*Duct diameter * 12)) * (No. of elbows)
Instrumentation	$13,079	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC = RTO Cost+ Straight Duct Cost+Elbows Cost
Freight	$6,540	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Purchased Equipment Cost (PEC)	**$150,409**	
Direct Installation Costs		
Foundation and Supports	$12,033	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Handling and Erection	$21,057	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Electrical	$6,016	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Piping	$3,008	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Insulation of Duct Work	$1,504	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Painting	$1,504	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Direct Installation Costs (DIC)	**$45,123**	
Total Direct Cost (TDC)	**$195,531**	**(TDC=PEC+DIC**
Indirect Costs		
Engineering	$15,041	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Construction and Field Expenses	$7,520	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contractor Fees	$15,041	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Start-up	$3,008	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Performance Test	$1,504	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contingencies	$4,512	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Indirect Costs (TIC)	**$46,627**	
Total Capital Cost (TCC)	**$242,158**	**TCC=TDC+TIC**
Annual Cost		
Operating labor	$16,425	Based on 3 shifts/day, 8,760 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Supervisory labor	$2,464	15% of Operating cost per EPA Cost Manual, Section 3.2, Table 2.10
Maintenance labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Maintenance materials	$18,068	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Natural gas	$24,838	As determined in Table E.7-3a
Electricity	$3,203	
Catalyst Replacement	$1,444	Catalyst replacement costs = (volume of catalyst) * (price of catalyst, $/ft3) * (catalyst capital recovery factor) Catalyst volume is determined in Table E.6-3a Recovery factor at 7% interest rate over 4 years = 0.2952 Catalyst Price = $650/ft^3
Overhead	$33,014	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.2, Table 2.10
Insurance, administrative	$7,265	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual Section 3.2, Table 2.10
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$22,858	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$147,646**	
Total Cost per ton VOC controlled	**$414,444**	Based on 0.375 tpy baseline and 95% control; 0.356 tons removed

Table E.7-3a VOC BACT Energy Cost Analysis: Catalytic Oxidizer on Boiler Nos. 1 – 4 (each)

Catalytic Oxidizer Input Parameters

Gas flowrate:	2,500	[acfm]
Reference temperature:	77	[^oF]
Inlet gas temperature:	380	[^oF]
Gas flowrate:	1,598	[scfm]
Inlet gas density:[1]	0.047	[lb/acf]
Primary heat recovery:	0.700	[fraction]
Waste gas heat content:[2]	0.270	[Btu/lb]
Waste gas heat capacity:[3]	0.248	[Btu/lb-^oF]
Combustion temperature:	750	[^oF]
Preheat Exit Temperature:	639	[^oF]
Fuel heat of combustion:	23,808	[Btu/lb]
Fuel density:[4]	0.041	[lb/ft^3]

Catalytic Oxidizer Design Parameters

Total Auxiliary Fuel Requirement:[5]	0.22	[lb/min]
Total Auxiliary Fuel Requirement:[5]	5.39	[scfm]
Total Gas Flowrate:	1,603	[scfm]
Total Catalyst Volume:[6]	7.52	[ft^3]

VOC Concentration and Heat of Combustion (Waste Gas) Calculations

	Ethane	
Potential Emissions:	0.375	[tpy]
Molecular Weight of VOC:	30.07	[lb/lb-mol]
Concentration of VOC by Weight:[7]	12.1	[ppmw]
Concentration of VOC by Volume:[8]	11.6	[ppmv]
Waste Gas O2 Content:	20.9	[%]
Lower Explosive Limit (LEL) of VOC:	3	[%]
LEL of VOC/Air Mixture:	0.039	[%]
Heat of Combustion of VOC:	22,323	[Btu/lb]
Heat of Combustion of Waste Gas:[2]	0.270	[Btu/lb]
Heat of Combustion of Waste Gas:	0.020	[Btu/scf]

Utility Cost Inputs	Average Unit Cost[9, 10]	Unit	Hours per Year		
Natural Gas[11]	8.76 $/Mscf	0.324 Mscf/hr	8,760	$	24,837.55
Electricity[12]	0.056 $/kWh	6.57 kW	8,760	$	3,203.43

Footnotes

1 Based on ideal gas equation at waste gas exhaust temperature assuming waste gas is principally air.

2 Heat of combustion per pound of inlet waste gas developed from heat of combustion of ethane multiplied by the concentration by weight (ppmw) of ethane.

3 Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996

4 Auxiliary fuel is natural gas with heating value assumed at 1,020 Btu/scf.

5 Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).

6 Catalyst volume is determined by the following equation: Φ = (Waste Gas flow rate) / (catalyst volume)
Φ = space velocity, h-1 and waste gas flow is specified in cu feet/hour. Φ = 20,000 h-1, per Sec 3.2 Subsection 2.4.3 of the Cost Manual
Therefore, catalyst volume = [(waste gas flow rate) * (60 min/hrs) * (460 + inlet temp) / (460 + ref temp)] / 20,000 h-1

7 Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (8760 hrs/yr) / (60 min/hr)) * 1000000 / (Gas flowrate, acfm) * (Inlet gas density, lb/f^3).

8 Parts per million concentration by volume to weight conversion from AP-42 Appendix A.

9 Natural gas unit cost is the mean of the latest 6 years (2005-2010) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm

10 Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html

11 Natural Gas Units = (Auxiliary fuel requirement) * (60 min/hr) * (8,760 hr/year)

12 Electricity Units = [0.000117 * (Waste gas exhaust flow) * (Total system pressure drop, assumed 21" w.c.) / 0.6]] per EPA 452/B-02-001, Section 3.2, Equation 2.42.

Table E.7-4 VOC BACT Cost Analysis:
Biotrickling Filter on Boiler Nos. 1 – 4 (each)

Cost Element	Budget Ammount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Biofilter	$57,414	Source: Using Bioreactors to Control Air Pollution, EPA CATC, Table 6 Escalation Based on Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated Biofilter cost = [(M&S Index, 2nd Q 2010) / (M&S Index, 2000) * (25.1, $/acfm) * (actual gas flow rate, acfm)]
Heat Exchanger	$45,300	Engineering company (Matches Engineering) estimate for a 304 SS U-Tube Shell and Tube heat exchanger in 2007 Dollars (twin 4,303 ft^2 in parallel)
Straight Duct Cost	$14,051	Cost of 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$701	Cost of 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^ (0.0688 * Duct diameter * 12)) * (No. of elbows)
Instrumentation/Controls	$11,747	Cost factor (0.10 * EC) per EPA Cost Manual, Section 5.2, Table 1.3 EC = RTO Cost+ Straight Duct Cost+Elbows Cost
Freight	$5,873	Cost factor (0.05 * EC) per EPA Cost Manual, Section 5.2, Table 1.3
Total Purchase Equipment Cost (PEC)	**$135,086**	
Direct Installation Costs		Average cost factors for packed tower absorber used as best esimate for biotrickling filter (EPA Cost Manual Section 5.2, Ch. 1) where noted
Foundations and Support	$16,210	Cost factor (0.12 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Erection and Handling	$54,034	Cost factor (0.40 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Electrical	$1,351	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Piping	$40,526	Cost factor (0.30 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Insulation	$1,351	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Painting	$1,351	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Site Preparation costs	$13,509	Site preparation and building costs are assumed to be 10% of purchased equipment costs per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
Direct Installation Cost (DIC)	**$128,332**	
Total Direct Costs	**$263,418**	
Indirect Costs		
Engineering/Supervision	$13,509	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Construction/Field	$13,509	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Contractor Fees	$13,509	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Start-up	$1,351	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Performance Test	$1,351	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Contingencies	$4,053	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Total Indirect Cost	**$47,280**	
Total Capital Costs	**$310,698**	
Annual Cost		
Operating Labor	$16,425	Based on 3 shifts/day, 8,760 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
Supervisory Labor	$2,464	15% of Operating cost per EPA Cost Manual, Section 5.2, Table 1.4
Maintenance Labor	$18,068	Based on 3 shifts/day, 8,760 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
Maintenance Materials	$6,214	Maintenance materials 2% of the total capital cost per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
Biofilter Media Cost	$3,148	Source: Table 9 of EPA 456-R-03-003 "Using Bioreactors to Control Air Pollution" Escalation Based on Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated Media cost = (M&S Index, 2nd Q 2010) / (M&S Index, 2003) * (1.42, $/acfm) * (actual gas flow rate, acfm)
Electricity (Biofilter)	$2,143	As determined in Table E.7-4a
Water	$56	
Overhead	$25,902	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 5.2, Table 1.4
Insurance, administrative	$9,321	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual, Section 5.2, Table 1.4
Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery	$34,113	Total Capital Cost * Capital Recovery Factor
Total Annualized Cost	**$115,433**	
Total Cost per ton VOC controlled	**$342,022**	Based on 0.375 tpy baseline and 90% control; 0.338 tons removed

Table E.7-4a VOC BACT Energy Cost Analysis: Biotrickling Filter on Boiler Nos. 1 – 4 (each)

Biotrickling Filter Input Parameters	Gas flowrate:	2,500	[acfm]
	Reference temperature:	77	[°F]
	Inlet gas temperature:	380	[°F]
	Gas flowrate:	1,598	[scfm]
	Inlet gas density:[1]	0.047	[lb/acf]
	Fractional moisture content of inlet gas:	10%	
Shell-and-Tube Heat Exchanger Parameters			
Inlet at 10% moisture, 380 °F:			
	Mass flow rate of water vapor:[2]	7.5	[lb/min]
	Mass flow rate of dry air:[3]	108.3	[lb/min]
	Total mass flow rate:	115.8	[lb/min]
	Gas mixing ratio:[4]	0.069	[lb/lb]
	Gas mixing ratio:[4]	483	[gr/lb]
	Enthalpy of gas:[5]	177.7	[Btu/lb]
	Temperature of cool fluid at inlet:	70	[°F]
Outlet at 100% humidity, 100 °F:			
	Gas temperature to biofilter:[6]	100	[°F]
	Enthalpy of gas:[5]	71.8	[Btu/lb]
	Change in enthalpy:	105.9	[Btu/lb]
	Temperature of cool fluid at outlet:	80	[°F]
	Heat transfer rate:[7]	0.74	[MMBtu/hr]
	Heat transfer coefficient:[8]	20.0	[Btu/ft²*hr*°F]
	Log mean temperature difference:[9]	105.8	[°F]
	Total surface area:[10]	348	[ft²]
	Gas humid volume:[5]	15.09	[ft³/lb]
	Standard gas flow rate:[11]	1,635	[scfm]
	Actual gas flow rate:	1,705	[acfm]
Potential Emissions			
	Potential VOC Emissions:	0.375	[tpy]
	Potential VOC Emissions from Fuel Combustion:[12]	0	[tpy]
	Tons VOC Reduced with 90% efficiency:[13]	0.338	[tpy]

Utility Cost Inputs	Average Unit Cost[14]	Unit[15, 16]	No. Hours per Year		
Electricity	0.056 $/kWh	4.4 kW	8,760	$	2,143.19
Water	0.30 $/kgal	0.021 kgal/hr	8,760	$	55.60

Footnotes	
1	Based on Ideal Gas Equation at waste gas exhaust temperature assuming waste gas is principally air.
2	Mass flow rate of water vapor (lb/min) = (flowrate, scfm)*(moisture content)*(molecular weight/volume of one mole of air)
3	Mass flow rate of air (lb/min) = (flowrate, scfm)*(1-moisture content)*(molecular weight/volume of one mole of air)
4	Mixing ratio = ratio of mass of water vapor to mass of dry air
5	Calculated using psychrometric equations
6	Temperature at which biomass can survive
7	Heat transfer rate, MMBtu/hr = (total mass flow rate, lb/min) * (change in enthalpy, Btu/lb) * (60 min/hr) / (10^6 Btu/MMBtu)
8	Source: Weider, Seader, and Lewin. "Product and Process Design Principles, 2nd edition." p. 431, Table 13.5, "Typical Overall Heat Transfer Coefficients for Shell-and-Tube Heat Exchangers." Shell side water, tube side air (2004)
9	T_{lm}, °F = (($T_{h,o}$-$T_{c,o}$) - ($T_{h,i}$-$T_{c,i}$)) / ln(($T_{h,o}$ - $T_{c,o}$) / ($T_{h,i}$-$T_{c,i}$)) where i is inlet, o is outlet, h is hot air, and c is cool fluid
10	Area, ft² = (heat transfer rate) / ((Heat transfer coefficient) * (log mean temperature difference))
11	Gas flow rate (scfm) = (heat exchanger outlet gas humid volume, ft³/lb) * (mass flow rate of air, lb/min)
12	Potential VOC emissions from fuel combustion (tpy) of natural gas
13	100 percent capture and 90 percent destruction efficiency considered.
14	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
15	Source: Average of power demand specifications from two vendor quotes for biotrickling filters at 24,338 scfm. Electricity Unit = ((65.4 kW) / (24,338 scfm exhaust gas)) * (standard gas flow rate, scfm)
16	Source: Average of water usage specifications from two vendor quotes for biotrickling filters at 24,338 scfm. Water cost =((5.25 gal/min) * (60 min/hr) / (1000 gal/kgal) / (24338 scf/min)) * (standard gas flow rate, scfm) Water cost is per Chapter 1.4.1.2 of EPA Air Pollution Control Cost Manual (EPA 452/B-02-001) Section 3.1 for Carbon Adsorbers (closest available reference for water cost from non-municipal sources).

Table E.7-5: Energy and Environmental Impact Summary for Boiler Nos. 1 – 4 (each)

Control Technology	Resource Consumption: Water (MGD)[1]	Resource Consumption: Gas (Mscf/yr)[1]	Resource Consumption: Electricity (kWh/yr)[1]	Energy Equivalents: Total Energy Consumed (MMBtu/yr)[2]	Energy Equivalents: Total Energy Consumed (MMBtu/hr)[3]
Carbon Adsorber	0	0	0	0	0
Recuperative Thermal Oxidation	0	8,099	11,023	8,298	0.947
Catalytic Oxidation	0	2,835	57,512	3,088	0.353
Biofiltration	Nil	0	38,477	131	0.015
Good Combustion Techniques	0	0	0	0	0

Control Technology	Collateral Emissions: NO_x (tpy)[4]	GHG (tpy CO_2e)[5]	VOC → GHG (tpy CO_2e)[6]	Total GHG (tpy CO_2e)[7]	CO (tpy)[8]	VOC (tpy)[9]	SO_2 (tpy)[10]	Total PM (tpy)[11,12]
Carbon Adsorber	0.00	0.00	1.065	1.07	0.00	0.00	0.00	0.00
Recuperative Thermal Oxidation	0.405	489	1.054	490	0.340	0.022	0.002	0.031
Catalytic Oxidation	0.142	171	1.022	172	0.119	0.008	0.001	0.011
Biofiltration	0.00	0.00	0.939	0.939	0.00	0.00	0.00	0.00
Good Combustion Techniques	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Notes	
1	Per cost-effectiveness calculation sheets. Carbon adsorber utilities include cooling water usage, water and gas used for steam production.
2	Total Energy Consumed, MMBtu/yr = (Gas Consumption, Mscf/yr) / (1,000 Mscf/MMscf) * (1,020 MMBtu/MMscf) + (Electricity Consumption, kWh/year) * (3413 Btu-hr/kWh) / (10^6 Btu/MMBtu
3	Total Energy Consumed, MMBtu/hr = (Total Energy Consumed, MMBtu/yr) / (8,760 hr/yr)
4	Estimated NO_x emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1, NO_x emissions from small uncontrolled boilers. NO_x tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (100 lb NO_x/MMscf) / (2000 lb/ton)
5	Estimated greenhouse gas (GHG) emissions from natural gas combustion in control device calculated using AP-42 emission factors, 5th Edition, Table 1.4-2. Combined GHG Emission Factor, lb CO_2e/MMscf = (120,000 lb CO_2/MMscf) * (CO_2 GWP =1) + (2.2 lb N_2O/MMscf) * (N_2O GWP=310) + (2.3 lb CH_4/MMscf) * (CH_4 GWP=21) GHG Emissions, tpy CO_2e = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (GHG EF=120,730 lb CO_2e/MMscf) / (2000 lb/ton)
6	GHG emissions from VOC destruction = (tons of VOC destroyed) * (2 mol CO_2/1 mol Ethane) * [(44.01 g/mol CO_2) / (30.07 g/mol ethane) * (CO_2 GWP=1)]
7	Sum of GHG emissions from natural gas combustion and VOC destruction.
8	Estimated CO emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-1. CO, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (84 lb CO/MMscf) / (2000 lb/ton)
9	Estimated VOC emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. VOC, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (5.5 lb VOC/MMscf) / (2000 lb/ton)
10	Estimated SO_2 emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. SO_2, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (0.6 lb SO_2/MMscf) / (2000 lb/ton)
11	Estimated PM emissions from natural gas combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.4-2. PM, tpy = (Gas Consumption, Mscf) * (1 MMscf/1000 Mscf) * (7.6 lb PM/MMscf) / (2000 lb/ton)
12	Total PM includes filterables and condensables. All PM assumed to be <2.5 microns

Table E.8-1 VOC BACT Cost Analysis:
Fixed-bed Carbon Adsober System on Emergency Generator Nos. 1 – 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Absorber Vessel Cost	$325,019	Base cost per EPA Cost Manual Section 3.1, Equation 1.27 in 1999 dollars Cost correlations range: 4,000 to 500,000 scfm. Escalation Based on Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated Carbon Adsorber cost = [(M&S Index, 2nd Q 2010)/(M&S Index, 1999) *(Adsorber Cost, 1999 Dollars)]
Straight Duct Cost	$55,911	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) *(Length of ducting)
Elbows Cost	$4,170	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688 * Duct diameter * 12)) * (No. of elbows)
Instrumentation/Controls	$38,510	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.1, Table 1.3 EC = RTO Cost+ Straight Duct Cost+Elbows Cost
Freight	$19,255	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.1, Table 1.3
Total Purchased Equipment Cost (PEC)	**$442,865**	
Direct Installation Costs		
Foundations and Support	$35,429	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Erection and Handling	$62,001	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Electrical	$17,715	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Piping	$8,857	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Insulation	$4,429	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Painting	$4,429	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Direct Installation Costs (DIC)	**$132,860**	
Total Direct Cost (TDC)	**$575,725**	**TDC=PEC+DIC**
Indirect Costs		
Engineering	$44,287	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Construction/Field	$22,143	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Contractor Fees	$44,287	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Start-up	$8,857	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Performance Test	$4,429	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Contingencies	$13,286	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.1, Table 1.3
Total Indirect Costs (TIC)	**$137,288**	
Total Capital Cost (TCC)	**$713,013**	**(TCC=TDC+TIC**
Annual Cost		
Operating Labor	$938	Based on 3 shifts/day, 500 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.1, Table 1.6 Labor Cost = shifts * hours/shift * hourly rate
Supervisory Labor	$141	15% of Operator per EPA Cost Manual Section 3.1, Table 1.6
Maintenance Labor	$1,031	Based on 3 shifts/day, 500 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.1, Table 1.6 Labor Cost = shifts * hours/shift * hourly rate
Maintenance Materials	$1,031	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.1, Table 1.6
Carbon Replacement Cost	$1	Carbon Cost and Labor Carbon replacement cost based on of EPA Cost Manual Section 3.1, Chapter 1.4.1.4 with $1/lb carbon cost and replacement labor at $0.05/lb carbon replaced. Recovery factor for a 5-year life and a 7% interest. Carbon Replacement Cost = ((Taxes & Freight Factor * Carbon Cost)+Carbon Replacement Cost) * (Carbon requirement * Capital Recovery Factor)
Steam	$30	As determined in Table E.8-1a
System, Cool/Dry Fans	$85	
Cooling Water	$3	
Overhead	$1,884	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.1, Table 1.6
Insurance, administrative	$21,390	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual, Section 3.1, Table 1.6
Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$78,285	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$104,820**	
Total Cost per ton VOC controlled	**$259,296**	Based on 0.413 tpy baseline and 98% control; 0.404 tons removed

Table E.8-1a VOC BACT Energy Cost Analysis: Fixed-bed Carbon Adsober System on Emergency Generator Nos. 1 – 4 (each)

Fixed-bed Carbon Adsorber Input Parameters

Parameter	Value	Units
Gas flowrate:	16,103	[acfm]
Inlet gas temperature:	869	[^oF]
Number of Adsorbing Vessels (N_a):	4	[ ]
Number of Desorbing Vessels (N_d):	2	[ ]
Capacity Factor (f):[1]	1.500	[ ]
Carbon Equilibrium Capacity (w_e):[2]	0.67	[lb VOC/lb C]
Working Capacity (w_c):[3]	0.34	[lb VOC/lb C]
Adsorption Time (q_a):[4]	12	[hrs]
Desorption Time (q_d):[4]	4	[hrs]
Carbon Requirement for Continuous System (M_c):[5]	5.06	[lb]
Superficial Bed Velocity (v_b):[6]	65	[fpm]
Carbon Vessel Diameter (D):[7]	8.88	[ft]
Carbon Vessel Length/Height (L):[8]	4.00	[ft]
Carbon Vessel Surface Area (S):[9]	235.48	[ft^2]
Carbon Bed Thickness (t_b):[10]	0.01	[in]
Carbon Bed Pressure Drop ($D p_b$):[11]	0.002	[inH_2O]
Total System Pressure Drop ($D p_s$):[11]	1.00	[inH_2O]

Potential Emissions

Parameter	Value	Units
Potential VOC Emissions:	0.413	[tpy]
Potential VOC Emissions from Fuel Combustion:[12]	0	[tpy]
Tons VOC Reduced:[13]	0.404	[tpy]

Utility Cost Inputs	Average Unit Cost[14, 15]	Usage		
Steam[16]	10.51 $/klbs	2.89 klbs/yr	$	30.35
System, Cool/Dry Fans[17]	0.056 $/kWh	1,529 kWh/yr	$	85.17
Cooling Water[18]	0.30 $/kgal	9.90 kgal/yr	$	2.97

Footnotes

1 The capacity factor was determined from Equation 1.11 of EPA Air Pollution Control Cost Manual (EPA 452/B-02-001) Section 3.1 for continously operated systems.
2 Source: I.I. El-Sharkawy, B.B. Saha, K. Kuwahara, S. Koyama, and K.C., NG, Adsorption Rate Measurements of Activated Carbon Fiber/ Ethanol Pair for Adsorption Cooling System Application, White Paper, Figure 2, Ethanol Uptake on Activated Carbon with Time at Adsorption Temperature. Carbon equilibrium capacity based on 67% by mass at 27 ^oC. Typically, the carbon equilibrium capacity is based on application of the Freundlich isotherm function and partial pressure of the VOC in the gas stream. The Freundlich isotherm constants for ethanol were not available to apply this function.
3 Working capacity is 50% of equilibrium capacity per Section 3.1, Equation 1.15 of EPA 452/B-02-001
4 Time selected based on daily adsorption/desorption cycle.
5 Carbon mass required for each fixed bed determined from Equation 1.14 of EPA 452/B-02-001 Section 3.1 for continuously operating systems.
6 The superficial bed velocity was chosen based on the guidance in Chapter 1.3.1.2 of EPA Air Pollution Control Cost Manual (EPA 452/B-02-001) Section 3.1
7 The vessel diameter was determined from Equation 1.21 of EPA Air Pollution Control Cost Manual (EPA 452/B-02-001) Section 3.1.
8 The vessel length was determined from Equation 1.23 of EPA 452/B-02-001 Section 3.1 plus 2 feet clearance for gas distribution and disengagement.
9 The vessel surface area = (Π) * (Vessel diameter, D) * [(Vessel length, L) + (Vessel diameter, D)/2)] per EPA 452/B-02-001 Section 3.1, Eqn. 1.24
10 Carbon bed thickness determined from Equation 1.22 of EPA 452/B-02-001 Section 3.1 for carbon density of 30 lb/ft^3.
11 Carbon bed and total system pressure drop determined from Equations 1.30 and 1.32 of EPA 452/B-02-001 Section 3.1
12 Potential VOC emissions from fuel combustion (tpy) of natural gas included in the potential emissions limit
13 100 percent capture and 98 percent destruction efficiency considered.
14 Steam cost is per US EPA Cost Manual, 6th Edition, Section 3.1, Eqn 1.28.
Steam prices are based on 120% of the fuel cost (natural gas) and assuming 1 MMBtu/1000 lb steam.
Natural gas unit cost is the mean of the latest 6 years (2004-2009) of annual average natural gas price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see
http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_SGA_a.htm
15 Electricity unit cost is the mean of the latest 6 years (2003-2008) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of
http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
16 Steam requirement estimated at 3.5 lb/lb VOC adsorbed per Equation 1.28 of EPA 452/B-02-001 Section 3.1.
17 System and bed cooling/drying fan power requirements determined from Equations 1.32 and 1.33 of EPA 452/B-02-001 Section 3.1 for the calculated system pressure drop. System fan runs 500 hours/year. Volumetric flow rate for the bed cooling/drying fan was determined at 100 cfm per pound of carbon with an operating factor of 0.4 for the number of hours of the regeneration cycle needed for cooling/ drying. Average horsepower is converted to kilowatts by multiplying by 0.746 kW/hp.
18 Cooling water requirements determined by multiplying steam requirement by 3.43 per Equation 1.29 and Cooling water cost is per EPA 452/B-02-001 Section 3.1, Chapter 1.4.1.2.

Table E.8-2 VOC BACT Cost Analysis:
Recuperative Thermal Oxidizer on Emergency Generator Nos. 1 – 4 (each)

Cost Element	Budget Amount	Comments
Capital Cost		
Direct Costs		
Purchased Equipment Costs (PEC)		
Recuperative Thermal Oxidizer (70% heat recovery - escalated)	$262,169	Base cost per EPA Cost Manual Section 3.2, Equation 2.32; in 1999 dollars Cost correlations range: 500 to 50,000 scfm Escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010) / (M&S Index,1999) * (21,342 + (Waste gas flowrate)$^{0.25}$)]
Straight Duct Cost	$32,016	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$1,592	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688*Duct diameter * 12)) * (No. of elbows)
Instrumentation	$29,578	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC = RTO Cost+ Straight Duct Cost+Elbows Cost
Freight	$14,789	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Purchased Equipment Cost (PEC)	**$340,143**	
Direct Installation Costs		
Foundation and Supports	$27,211	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Handling and Erection	$47,620	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Electrical	$13,606	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Piping	$6,803	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Insulation of Duct Work	$3,401	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Painting	$3,401	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Direct Installation Costs (DIC)	**$102,043**	
Total Direct Cost (TDC)	**$442,186**	**TDC=PEC+DIC**
Indirect Costs		
Engineering	$34,014	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Construction and Field Expenses	$17,007	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contractor Fees	$34,014	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Start-up	$6,803	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Performance Test	$3,401	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Contingencies	$10,204	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
Total Indirect Costs (TIC)	**$105,444**	
Total Capital Cost (TCC)	**$547,630**	**TCC=TDC+TIC**
Annual Cost		
Operating labor	$938	Based on 3 shifts/day, 500 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Supervisory labor	$141	15% of Operating cost per EPA Cost Manual, Section 3.2, Table 2.10
Maintenance labor	$1,031	Based on 3 shifts/day, 500 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
Maintenance materials	$1,031	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
Natural gas	$3,287	As determined in Table E.8-2a
Overhead	$1,884	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 3.2, Table 2.10
Insurance, administrative	$16,429	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual Section 3.2, Table 2.10
Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital recovery	$51,692	Total Capital Cost * Capital Recovery Factor
Total Annual Cost	**$76,433**	
Total Cost per ton VOC Reduced	**$189,073**	Based on 0.413 tpy baseline and 98% control; 0.404 tons removed

Table E.8-2a VOC BACT Energy Cost Analysis: Recuperative Thermal Oxidizers on Emergency Generator Nos. 1 – 4 (each)

Regenerative Thermal Oxidizer Input Parameters	Gas flowrate:	16,103	[acfm]
	Reference temperature:	77	[^oF]
	Inlet gas temperature:	869	[^oF]
	Gas flowrate:	6,504	[scfm]
	Inlet gas density:[1]	0.030	[lb/acf]
	Primary heat recovery:	0.700	[fraction]
	Waste gas heat content:[2]	1.204	[Btu/lb]
	Waste gas heat capacity:[3]	0.255	[Btu/lb-^oF]
	Combustion temperature:	1,600	[^oF]
	Heat loss:	0.100	[fraction]
	Exit temperature:	1088	[^oF]
	Fuel heat of combustion:[4]	137,000	[Btu/gal]
Recuperative Thermal Oxidizer Design Parameters	Auxiliary Fuel Requirement:[5]	0.33	[gal/min]
	Auxiliary Fuel Requirement:[4,5]	0.045	[MMBtu/min]
	Exhaust Flow Rate from Auxiliary Burner Combustion:[6]	465	[scfm]
	Total Waste Gas Flowrate:	6,504	[scfm]
VOC Concentration and Heat of Combustion (Waste Gas) Calculations		Propylene	
	Potential Emissions:	0.413	[tpy]
	Molecular Weight of VOC:	42.08	[lb/lb-mol]
	Concentration of VOC by Weight:[7]	57	[ppmw]
	Concentration of VOC by Volume:[8]	39	[ppmv]
	Waste Gas O_2 Content:	20.9	[%]
	Lower Explosive Limit (LEL) of VOC:	3	[%]
	LEL of VOC/Air Mixture:	0.131	[%]
	Heat of Combustion of VOC:	21,048	[Btu/lb]
	Heat of Combustion of Waste Gas:[2]	1.204	[Btu/lb]
	Heat of Combustion of Waste Gas:	0.089	[Btu/scf]

Utility Cost Inputs	Average Unit Cost[8]	Unit[10]	Hours per Year		
Diesel Fuel (ULSD)	2.43 $/gal	2.70 gal/hr	500	$	3,287

Footnotes	
1	Based on Ideal Gas Equation at waste gas exhaust temperature, assuming waste gas is principally air.
2	Heat of combustion per pound of inlet waste gas developed from heat of combustion of propylene multiplied by the concentration by weight (ppmw) of propylene.
3	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996.
4	Auxiliary fuel is diesel with heating value assumed at 137,000 Btu/gal
5	Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).
6	Flow Rate (scfm)= (Aux. Fuel Requirement, MMBtu/min) * (10,320 wscf/MMBtu) Combustion F-Factor per EPA Test Method 19, Table 19-2
7	Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (500hr/yr) / (60 min/hr)) * 1000000 / (Gas flowrate, acfm) * (Inlet gas density, lb/ft^3).
8	Parts per million concentration by weight to volume conversion from AP-42 Appendix A.
9	Diesel fuel unit cost is the mean of the 3 years (2007-2009) of annual average ULSD price data available for industrial sector consumers in the Gulf Coast Region per US Dept. of Energy, Energy Information Administration; see http://www.eia.gov/dnav/pet/pet_pri_dist_dcu_R30_a.htm
10	Diesel Fuel Units = (Auxiliary fuel requirement, gal/min) * (60 min/hr)

Table E.8-3 VOC BACT Cost Analysis:
Catalytic Oxidizer on Emergency Generator Nos. 1 – 4 (each)

	Cost Element	Budget Amount	Comments
			Capital Cost
Direct Costs			
	Purchased Equipment Costs (PEC)		
	Catalytic Oxidizer (70 % heat recovery - escalated)	$252,852	Base cost per EPA Cost Manual Section 3.2, Equation 2.37; in 1999 dollars Cost correlations range: 2,000 to 50,000 scfm Escalated to 2010 dollars using Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated oxidizer costs = [(M&S Index, 2nd Q 2010)/(M&S Index,1999) * (1,443 * (Total gas flowrate)$^{0.5527}$)]
	Straight Duct Cost	$32,016	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
	Elbows Cost	$1,592	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^(0.0688*Duct diameter * 12)) * (No. of elbows)
	Instrumentation	$28,646	Cost factor (0.10 * EC) per EPA Cost Manual, Section 3.2, Table 2.8 EC = RTO Cost+ Straight Duct Cost+Elbows Cost
	Freight	$14,323	Cost factor (0.05 * EC) per EPA Cost Manual, Section 3.2, Table 2.8
	Total Purchased Equipment Cost (PEC)	**$329,429**	
	Direct Installation Costs		
	Foundation and Supports	$26,354	Cost factor (0.08 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Handling and Erection	$46,120	Cost factor (0.14 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Electrical	$13,177	Cost factor (0.04 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Piping	$6,589	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Insulation of Duct Work	$3,294	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Painting	$3,294	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Direct Installation Costs (DIC)	**$98,829**	
	Total Direct Cost (TDC)	**$428,257**	**TDC=PEC+DIC**
Indirect Costs			
	Engineering	$32,943	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Construction and Field Expenses	$16,471	Cost factor (0.05 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Contractor Fees	$32,943	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Start-up	$6,589	Cost factor (0.02 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Performance Test	$3,294	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Contingencies	$9,883	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 3.2, Table 2.8
	Total Indirect Cost (TIC)	**$102,123**	
Total Capital Cost (TCC)		**$530,380**	**TCC=TDC+TIC**
			Annual Cost
	Operating labor	$938	Based on 3 shifts/day, 500 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
	Supervisory labor	$141	15% of Operating cost per EPA Cost Manual, Section 3.2, Table 2.10
	Maintenance labor	$1,031	Based on 3 shifts/day, 500 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per EPA Cost Manual, Section 3.2, Table 2.10 Labor Cost = shifts * hours/shift * hourly rate
	Maintenance materials	$1,031	Considered equal to maintenance labor cost per EPA Cost Manual, Section 3.2, Table 2.10
	Natural gas	$2,135	As determined in Table 1.9-4
	Catalyst Replacement	$0	Catalyst is expected to last the entire lifetime of the Catalytic Oxidizer as it will only be run 500 hrs/yr
	Overhead	$1,884	Overhead = 0.6*(cost of labor and materials) Per EPA Cost Manual, Section 3.2, Table 2.10
	Insurance, administrative	$15,911	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual Section 3.2, Table 2.10
	Capital Recovery Factor	9.44%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 20 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
	Capital recovery	$50,064	Total Capital Cost * Capital Recovery Factor
Total Annual Cost		**$73,136**	
Total Cost per ton VOC Reduced		**$186,630**	Based on 0.413 tpy baseline and 95% control; 0.392 tons removed

Table E.8-3a VOC BACT Energy Cost Analysis: Catalytic Oxidizer on Emergency Generator Nos. 1 – 4 (each)

Catalytic Oxidizer Input Parameters	Gas flowrate:	16,103	[acfm]
	Reference temperature:	77	[°F]
	Inlet gas temperature:	869	[°F]
	Gas flowrate:	6,504	[scfm]
	Inlet gas density:[1]	0.030	[lb/acf]
	Primary heat recovery:	0.700	[fraction]
	Waste gas heat content:[2]	1.204	[Btu/lb]
	Waste gas heat capacity:[3]	0.248	[Btu/lb-°F]
	Combustion temperature:	750	[°F]
	Preheat Exit Temperature:	786	[°F]
	Fuel heat of combustion:	137,000	[Btu/gal
Catalytic Oxidizer Design Parameters	Total Auxiliary Fuel Requirement:[5]	0.029	[gal/min]
	Total Auxiliary Fuel Requirement:[5]	0.004	[MMBtu/min]
	Exhaust Flow Rate from Auxiliary Burner Combustion:[6]	41	[scfm]
	Total Gas Flowrate:	6,504	[scfm]
	Total Catalyst Volume:[7]	48.29	[ft^3]
VOC Concentration and Heat of Combustion (Waste Gas) Calculations		Propylene	
	Potential Emissions:	0.413	[tpy]
	Molecular Weight of VOC:	42.08	[lb/lb-mol]
	Concentration of VOC by Weight:[8]	57	[ppmw]
	Concentration of VOC by Volume:[9]	39	[ppmv]
	Waste Gas O_2 Content:	20.9	[%]
	Lower Explosive Limit (LEL) of VOC:	3	[%]
	LEL of VOC/Air Mixture:	0.131	[%]
	Heat of Combustion of VOC:	21,048	[Btu/lb]
	Heat of Combustion of Waste Gas:[2]	1.204	[Btu/lb]
	Heat of Combustion of Waste Gas:	0.090	[Btu/scf]

Utility Cost Inputs	Average Unit Cost[10]	Unit[11]	Hours per Year	
Diesel Fuel (ULSD)	2.43 $/gal	1.76 gal/hr	500	$ 2,135.26

Footnotes	
1	Based on ideal gas equation at waste gas exhaust temperature assuming waste gas is principally air.
2	Heat of combustion per pound of inlet waste gas developed from heat of combustion of propylene multiplied by the concentration by weight (ppmw) of propylene.
3	Heat capacity, c_p, of air at average control temperature; Thermodynamics 3rd Edition, Black and Hartley, 1996.
4	Auxiliary fuel is diesel with heating value assumed at 137,000 Btu/gal
5	Auxiliary fuel needed to sustain the combustion zone temperature using the procedure specified in EPA Air Pollution Control Cost Manual (EPA 452/B-02-001).
6	Flow Rate (scfm)= (Aux. Fuel Requirement, MMBtu/min) * (10,320 wscf/MMBtu) Combustion F-Factor per EPA Test Method 19, Table 19-2
7	Catalyst volume is determined by the following equation: Φ = (Waste Gas flow rate) / (catalyst volume) Φ = space velocity, h-1 and waste gas flow is specified in cu feet/hour. Φ = 20,000 h-1, per Sec 3.2 Subsection 2.4.3 of the Cost Manual Therefore, catalyst volume = [(waste gas flow rate) * (60 min/hrs) * (460 + inlet temp) / (460 + ref temp)] / 20,000 h-1
8	Concentration by weight = ((Potential to emit, tpy) * (2000 lb/ton) / (8760 hrs/yr) / (60 min/hr)) * 1000000 / (Gas flowrate, acfm) * (Inlet gas density, lb/ft^3).
9	Parts per million concentration by volume to weight conversion from AP-42 Appendix A.
10	Diesel fuel unit cost is the mean of the 3 years (2007-2009) of annual average ULSD price data available for industrial sector consumers in the Gulf Coast Region per US Dept. of Energy, Energy Information Administration; see http://www.eia.gov/dnav/pet/pet_pri_dist_dcu_R30_a.htm
11	Diesel Fuel Units = (Auxiliary fuel requirement, gal/min) * (60 min/hr)

Table E.8-4 VOC BACT Cost Analysis:
Biotrickling Filter on Emergency Generator Nos. 1 – 4 (each)

Cost Element	Budget Ammount	Comments
		Capital Cost
Direct Costs		
Purchased Equipment Costs (PEC)		
Biofilter - Escalated	$233,709	Source: Using Bioreactors to Control Air Pollution, EPA CATC, Table 6 Escalation Based on Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated Biofilter cost = [(M&S Index, 2nd Q 2010) / (M&S Index, 2000) * (25.1, $/acfm) * (actual gas flow rate, acfm)]
Heat Exchanger	$180,500	Engineering company (Matches Engineering) estimate for a 304 SS U-Tube Shell and Tube heat exchanger in 2007 Dollars (twin 4,303 ft^2 in parallel)
Straight Duct Cost	$33,315	Cost based upon 100 ft of ductwork using 304 SS plate from Section 2, Table 1.9 of EPA Cost Manual. Cost of straight ductwork = 6.29 * (12 * Duct diameter)^1.23) * (Length of ducting)
Elbows Cost	$1,682	Cost based upon 4 elbows constructed of 304 SS from Section 2, Table 1.10 of EPA Cost Manual. Cost of elbows = 74.2 * (e^ (0.0688 * Duct diameter * 12)) * (No. of elbows)
Instrumentation/Controls	$44,921	Cost factor (0.10 * EC) per EPA Cost Manual, Section 5.2, Table 1.3 EC = RTO Cost+ Straight Duct Cost+Elbows Cost
Freight	$22,460	Cost factor (0.05 * EC) per EPA Cost Manual, Section 5.2, Table 1.3
Total Purchase Equipment Cost (PEC)	**$516,588**	
Direct Installation Costs		Average cost factors for packed tower absorber used as best esimate for biotrickling filter (EPA Cost Manual Section 5.2, Ch. 1) where noted
Foundations and Support	$61,991	Cost factor (0.12 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Erection and Handling	$206,635	Cost factor (0.40 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Electrical	$5,166	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Piping	$154,976	Cost factor (0.30 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Insulation	$5,166	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Painting	$5,166	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Site Preparation costs	$51,659	Site preparation and building costs are assumed to be 10% of purchased equipment costs per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
Direct Installation Cost (DIC)	**$490,758**	
Total Direct Costs (TDC)	**$1,007,346**	**TDC=PEC+DIC**
Indirect Installation Cost		
Engineering/Supervision	$51,659	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Construction/Field	$51,659	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Contractor Fees	$51,659	Cost factor (0.10 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Start-up	$5,166	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Performance Test	$5,166	Cost factor (0.01 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Contingencies	$15,498	Cost factor (0.03 * PEC) per EPA Cost Manual, Section 5.2, Table 1.3
Total Indirect Cost (TIC)	$180,806	
Total Capital Costs (TCC)	**$1,188,151**	**TCC=TDC+TIC**
		Annual Cost
Operating Labor	$938	Based on 3 shifts/day, 500 operating hours per year at $30/hr, and a labor factor of 0.5 hrs/shift per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
Supervisory Labor	$141	15% of Operating cost per EPA Cost Manual, Section 5.2, Table 1.4
Maintenance Labor	$1,031	Based on 3 shifts/day, 500 operating hours per year at $33/hr, and a labor factor of 0.5 hrs/shift per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
Maintenance Materials	$23,763	Maintenance materials 2% of the total capital cost per Biofiltration of Ethanol Emissions from Bakery Operations, Dr. Rakesh Govind (1999), Preliminary Cost Analysis, page 9
Biofilter Media Cost	$12,815	Source: Table 9 of EPA 456-R-03-003 "Using Bioreactors to Control Air Pollution" Escalation Based on Marshall & Swift Equipment Cost Index for the second quarter of 2010 (M&S Index, 2nd Q 2010 = 1,461.3, M&S Index, 1999 = 1,068.3) Escalated Media cost = (M&S Index, 2nd Q 2010) / (M&S Index, 2003) * (1.42, $/acfm) * (actual gas flow rate, acfm)
Electricity (Biofilter)	$498	As determined in Table E.8-4a
Water	$13	
Overhead	$15,523	Overhead = 0.6*(cost of labor and materials) per EPA Cost Manual, Section 5.2, Table 1.4
Insurance, administrative	$35,645	Administrative costs based on 2% of capital cost and Insurance based on 1% of capital cost per EPA Cost Manual, Section 5.2, Table 1.4
Capital Recovery Factor	10.98%	Calculated using EPA Cost Manual Section 1, Eqn. 2.8a, using 7% interest (i) and 15 year equipment life: CRF= [i*(1+i)^(equipment life)] / [(1+i)^(equipment life)-1)]
Capital Recovery	$130,453	Total Capital Cost * Capital Recovery Factor
Total Annualized Cost	**$210,965**	
Total Cost per ton VOC controlled	**$568,257**	Based on 0.413 tpy baseline and 90% control; 0.371 tons removed

Table E.8-4a VOC BACT Energy Cost Analysis: Biotrickling Filter on Emergency Generator Nos. 1 – 4 (each)

Biotrickling Filter Input Parameters	Gas flowrate:	16,103	[acfm]
	Reference temperature:	77	[°F]
	Inlet gas temperature:	869	[°F]
	Gas flowrate:	6,504	[scfm]
	Inlet gas density:[1]	0.030	[lb/acf]
	Fractional moisture content of inlet gas:	10%	
Shell-and-Tube Heat Exchanger Parameters			
Inlet at 10% moisture, 869 °F:			
	Mass flow rate of water vapor:[2]	30.4	[lb/min]
	Mass flow rate of dry air:[3]	440.9	[lb/min]
	Total mass flow rate:	471.3	[lb/min]
	Gas mixing ratio:[4]	0.069	[lb/lb]
	Gas mixing ratio:[4]	483	[gr/lb]
	Enthalpy of gas:[5]	324.9	[Btu/lb]
	Temperature of cool fluid at inlet:	70	[°F]
Outlet at 100% humidity, 100 °F:			
	Gas temperature to biofilter:[6]	100	[°F]
	Enthalpy of gas:[5]	71.8	[Btu/lb]
	Change in enthalpy:	253.1	[Btu/lb]
	Temperature of cool fluid at outlet:	80	[°F]
	Heat transfer rate:[7]	7.16	[MMBtu/hr]
	Heat transfer coefficient:[8]	20.0	[Btu/ft²*hr*°F]
	Log mean temperature difference:[9]	211.2	[°F]
	Total surface area:[10]	1,694	[ft²]
	Gas humid volume:[5]	15.09	[ft³/lb]
	Standard gas flow rate:[11]	6,654	[scfm]
	Actual gas flow rate:	6,939	[acfm]
Potential Emissions			
	Potential VOC Emissions:	0.413	[tpy]
	Tons VOC Reduced with 90% efficiency:[12]	0.371	[tpy]

Utility Cost Inputs	Average Unit Cost[13]	Unit[14, 15]	No. Hours per Year		
Electricity	0.056 $/kWh	17.9 kW	500	$	497.95
Water	0.30 $/kgal	0.086 kgal/hr	500	$	12.92

Footnotes	
1	Based on Ideal Gas Equation at waste gas exhaust temperature assuming waste gas is principally air.
2	Mass flow rate of water vapor (lb/min) = (flowrate, scfm)*(moisture content)*(molecular weight/volume of one mole of air)
3	Mass flow rate of air (lb/min) = (flowrate, scfm)*(1-moisture content)*(molecular weight/volume of one mole of air)
4	Mixing ratio = ratio of mass of water vapor to mass of dry air
5	Calculated using psychrometric equations
6	Temperature at which biomass can survive
7	Heat transfer rate, MMBtu/hr = (total mass flow rate, lb/min) * (change in enthalpy, Btu/lb) * (60 min/hr) / (10^6 Btu/MMBtu)
8	Source: Weider, Seader, and Lewin. "Product and Process Design Principles, 2nd edition." p. 431, Table 13.5, "Typical Overall Heat Transfer Coefficients for Shell-and-Tube Heat Exchangers." Shell side water, tube side air (2004)
9	T_{lm}, °F = $((T_{h,o}-T_{c,o}) - (T_{h,i}-T_{c,i})) / \ln((T_{h,o} - T_{c,o}) / (T_{h,i}-T_{c,i}))$ where i is inlet, o is outlet, h is hot air, and c is cool fluid
10	Area, ft² = (heat transfer rate) / ((Heat transfer coefficient) * (log mean temperature difference))
11	Gas flow rate (scfm) = (heat exchanger outlet gas humid volume, ft³/lb) * (mass flow rate of air, lb/min)
13	100 percent capture and 90 percent destruction efficiency considered.
14	Electricity unit cost is the mean of the latest 6 years (2004-2009) of annual average electricity price data for industrial sector consumers in Georgia per US Dept. of Energy, Energy Information Administration; see Table 8 of http://www.eia.doe.gov/cneaf/electricity/st_profiles/georgia.html
15	Source: Average of power demand specifications from two vendor quotes for biotrickling filters at 24,338 scfm. Electricity Unit = ((65.4 kW) / (24,338 scfm exhaust gas)) * (standard gas flow rate, scfm)
16	Source: Average of water usage specifications from two vendor quotes for biotrickling filters at 24,338 scfm. Water cost =((5.25 gal/min) * (60 min/hr) / (1000 gal/kgal) / (24338 scf/min)) * (standard gas flow rate, scfm) Water cost is per Chapter 1.4.1.2 of EPA Air Pollution Control Cost Manual (EPA 452/B-02-001) Section 3.1 for Carbon Adsorbers (closest available reference for water cost from non-municipal sources).

Table E.8-5 Energy and Environmental Impact Summary for Emergency Generator Nos. 1 – 4 (each)

	Resource Consumption			Energy Equivalents	
Control Technology	Water (MGD)[1]	Diesel Fuel (gal/yr)[1]	Electricity (kWh/yr)[1]	Total Energy Consumed (MMBtu/yr)[2]	Total Energy Consumed (MMBtu/hr)[3]
Carbon Adsorber	Nil	Nil	1,529	5.22	0.010
Recuperative Thermal Oxidation	0	1,352	0	185	0.37
Catalytic Oxidation	0	879	0	120	0.24
Biofiltration	Nil	0	8,940	30.5	0.061
Good Combustion Techniques	0	0	0	0	0

	Emissions							
Control Technology	NO_x (tpy)[4]	GHG (tpy CO_2e)[5]	VOC → GHG (tpy CO_2e)[6]	Total GHG (tpy CO_2e)[7]	CO (tpy)[8]	VOC (tpy)[9]	SO_2 (tpy)[10]	Total PM (tpy)[11,12]
Carbon Adsorber	Nil	0.00	1.24	1.24	Nil	Nil	Nil	Nil
Recuperative Thermal Oxidation	0.014	15.1	1.24	16.4	0.003	0.0001	0.0001	0.002
Catalytic Oxidation	0.009	9.83	1.17	11.0	0.002	0.0001	0.0001	0.001
Biofiltration	0.00	0.00	1.05	1.05	0.00	0.00	0.00	0.00
Good Combustion Techniques	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Notes	
1	Per cost-effectiveness calculation sheets. Carbon adsorber utilities include cooling water usage, water and diesel used for steam production.
2	Total Energy Consumed, MMBtu/yr = (Diesel Fuel Consumption, gal/year) * (137,000 Btu/gal) / (10^6 Btu/MMBtu + (Electricity Consumption, kWh/year) * (3413 Btu-hr/kWh) / (10^6 Btu/MMBtu
3	Total Energy Consumed, MMBtu/hr = (Total Energy Consumed, MMBtu/yr) / (500 hr/yr
4	Estimated NO_x emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-1, NO_x emissions from small uncontrolled boilers. NO_x tpy = (Gas Consumption, gal) * (1 Kgal/1000 gal) * (20 lb NO_x/Kgal) / (2000 lb/ton)
5	Estimated greenhouse gas (GHG) emissions from diesel combustion in control device calculated using AP-42 emission factors, 5th Edition, Tables 1.3-8 and 1.3-12. Combined GHG Emission Factor, lb CO_2e/kgal = (22,300 lb CO_2/kgal) * (CO_2 GWP =1) + (0.260 lb N_2O/kgal) * (N_2O GWP=310) + (2.3 lb CH_4/MMscf) * (CH_4 GWP=21) GHG Emissions, tpy CO_2e = (Gas Consumption, gal) * (1 kgal/1000 gal) * (GHG EF=22,382 lb CO_2e/kgal) / (2000 lb/ton)
6	GHG emissions from VOC destruction = (tons of VOC destroyed) * (3 mol CO_2/1 mol Propylene) * [(44.01 g/mol CO_2) / (42.08 g/mol propylene) * (CO2 GWP=1)]
7	Sum of GHG emissions from natural gas combustion and VOC destruction.
8	Estimated CO emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-1. CO, tpy = (Gas Consumption, gal) * (1 kgal/1000 gal) * (5 lb CO/kgal) / (2000 lb/ton)
9	Estimated VOC emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-3. VOC, tpy = (Gas Consumption, gal) * (1 kgal/1000 gal) * (0.200 lb VOC/kgal) / (2000 lb/ton)
10	Estimated SO_2 emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-1. SO_2, tpy = (Gas Consumption, gal) * (1 kgal/1000 gal) * (142S lb SO_2/kgal) / (2000 lb/ton); S=sulfur content = 0.0015%
11	Estimated PM emissions from diesel combustion in control device calculated using AP-42 emission factor, 5th Edition, Table 1.3-1 and 1.3-2. PM, tpy = (Gas Consumption, gal) * (1 kgal/1000 gal) * (3.3 lb PM/kgal) / (2000 lb/ton) Total PM E.F. = 3.3 (Filterable E.F=2.0 lb/kgal and condensable E.F.=1.3 lb/kgal)
12	Total PM includes filterables and condensables. All PM assumed to be <2.5 microns

ATTACHMENT F

Detailed GHG BACT Analysis

VOLUME II, ATTACHMENT F
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F. Top-Down BACT Analysis: Greenhouse Gases (GHG)

According to U.S. EPA's November 2010 PSD and Title V Permitting Guidance for Greenhouse Gases (the "Guidance"), BACT analysis for GHG emissions should be conducted in a manner consistent with the historical practice of BACT analyses, using the 5-step "top-down" approach originally laid out in EPA's Draft 1990 Workshop Manual. Given that most GHG emissions are a result of fossil fuel combustion, EPA suggests that a GHG BACT analyses should consider energy efficiency measures that reduce the need for fuel combustion, either by combusting fuel more efficiently, using the energy produced more efficiently, or both. These measures are especially pertitnent given the relative lack of current end-of-pipe controls for GHG emissions.

The Guidance also specifies that while GHG BACT analyses can include control measures that can be used facility-wide, Step 1 of the process should not consider secondary emissions (for example, measures that reduce electrical demand from the grid at the facility and thereby result in reduced demand for fuel combustion at off-site electric generating units); however, these off-site effects could be considered in Step 4 as appropriate.[1]

The Guidance also notes that for BACT analysis for GHG control strategies, "it may be appropriate in some cases to assess the cost effectiveness of a control option in a less detailed quantitative (or even qualitative) manner"[2] relative to BACT analyses for other regulated NSR pollutants. EPA encourages the use of output-based BACT limits, where feasible and appropriate, and that GHG BACT limits should focus on long-term averages based on the cumulative, rather than acute, environmental impact of GHG emissions.[3]

F.1 GHG Review: Direct Fired Rotary Calciner Nos. 1 – 4

Greenhouse gases (GHG) including CO_2, N_2O, and CH_4 are emitted from the Direct-fired Rotary Calciners due primarily to the combustion of natural gas. Fuel combustion is the most practical means in order to achieve the necessary temperatures required for calcination.

Baseline GHG emissions for the direct-fired rotary calciner of approximately 36,715 tpy CO_2e are calculated based on AP-42 emission factors for external combustion of natural gas.[4] It has been shown historically that the organic content of kaolin clays in middle Georgia are typically less than 0.4%.[5] Therefore, emissions related to the organic content are minimal relative to those from fuel combustion and are not included in this baseline. The facility will implement a number of practices to ensure optimum energy efficiency and GHG emission minimization on the proposed direct-fired calciners. These measures include the following types of practices:

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1 PSD and Title V Permitting Guidance for Greenhouse Gases. U.S. EPA, Office of Air and Radiation, November 2010, at p. 25. No EPA Document ID available.

2 As above, at p. 43

3 As above, at p. 46 – 47

4 AP-42 Compilation of Emission Factors, 5th Edition, U.S. EPA OAQPS, January 1995, Chapter 1.4, Table 1.4-2. In this regard, any CO_2 emissions that may result from organic impurities in the kaolin clay material have been shown to be negliglbe and, thus for the pruposes of this BACT analysis have not been included.

5 Sedimentary Structure in Gray Kaolins of Georgia; Clays and Clay Minerals, Vol. 40, No. 5, 555-560, 1992.

- Reject Heat Recovery
- Efficient Process Design and Optimization
- Good Combustion Practices

<u>Step 1: Identify all control technologies</u>

At this early stage of regulation of GHG as an NSR pollutant, the number of available control technology determinations and developed guidance on what constitutes BACT for GHG for any emission unit type is extremely limited. This is further compounded by the fact that there are a limited number of Direct Fired Rotary Calciners in existence, and very few of those operate under similar conditions or produce a similar product as those proposed in this application. As such, there is virtually no precedent for controlling GHG emissions from these units. However, US EPA has provided a white paper on technologies to reduce GHG emissions from the Portland cement industry- "Available and Emerging Technologies For Reducing Greenhouse Gas Emissions from the Portland Cement Industry".[6] While there are substantial operational differences between Portland cement manufacturing and ceramic proppant manufacturing, there are also some basic similarities. To the extent that the related processes are similar, guidance applicable to the Portland cement industry in this document (the "White Paper") is of some use in establishing technologies which are relevant for consideration as controls for the proposed direct-fired rotary calciners.

It should be noted, though, that the White Paper explicitly states that it is not setting a policy on what constitutes BACT for the Portland cement industry; however, it identifies a large number of potentially applicable technologies that could be considered in a GHG BACT analysis for that industry. As such, this analysis will consider the technologies proposed in the White Paper that are relevant to ceramic proppant direct-fired rotary calciners.

This analysis also requires a somewhat different approach than typical PSD BACT analyses in that a larger number of control technologies are considered, and many of those control technologies are mutually complementary. Table F.1-1 below summarizes the control options considered for the proposed direct-fired rotary calciners. Note that, in accordance with the Guidance, this Step 1 analysis considers only those control options relevant for reducing <u>on-site</u> GHG emissions.

[6] Available and Emerging Technologies For Reducing Greenhouse Gas Emissions from the Portland Cement Industry. U.S. EPA, Office of Air and Radiation, October 2010. No EPA Document ID number provided.

Table F.1-1: Evaluated Control Options for GHG Emissions – Direct-fired Rotary Calciners (KLN1 – KLN4)

Option No.	Control Technology
1	Fluxes/Mineralizers to Reduce Required Kiln Temperature
2	Raw Material Substitution
3	Carbon Capture and Sequestration (CCS)
4	Fuel Switching
5	Baseline Control Measures

Option 1 – Fluxes/Mineralizers to Reduce Required Kiln Temperature

In cement manufacturing processes, processes additives can be used to lower the temperature required in the kiln for proper cement production. This allows for lower kiln temperatures, which can reduce the fuel requirements required to operate the kiln.

Option 2 – Raw Material Substitution

Cement kilns can use blend in substitute feedstocks such as fly ash to reduce the amount of raw material needed to make a given quantity of clinker. This is relevant in Portland cement production because there are process-related CO_2 emissions in addition to those from the fuel combustion itself; these emissions are from the calcination reaction of calcium carbonate from limestone, which dissociates into CO_2 and calcium oxide. To the extent that these substitute feedstocks displace usage of calcium carbonate that contributes to the process-related CO_2 emissions, the substitution decreases GHG emissions from the process.

Option 3 – Carbon Capture and Sequestration (CCS)

CCS in its simplest application provides a mechanism for carbon in the exhaust gas stream to be captured prior to being emitted to the atmosphere and is permanently stored or utilized for some other non-emissive purpose. There are a number of methods by which these systems work, but the functional mechanism and details are relatively unimportant for the purpose of this analysis.

Option 4 – Fuel Switching

For a given value of heat supplied, there is variation in the CO_2 emissions expected from each fuel. Among fossil fuels, coal has the highest carbon intensity[7] (i.e. the highest CO_2 emissions for a given amount of heat supplied), and natural gas has the lowest carbon intensity. As such, a combustion source can sometimes reduce its GHG emissions by switching from a relatively more carbon intensive fuel, such as coal, to one with lower carbon intensity, such as oil or natural gas.

[7] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2008. U.S. EPA Document 430-R/10-006, April 2010, at page 3-4

Option 5 – Baseline Control Measures

As described previously, the facility plans to use a number of practices to optimize its energy efficiency and minimize its GHG emissions. These can generally be categorized in the following groups:

- Reject Heat Recovery
- Efficient Process Design and Optimization
- Good Combustion Practices

Reject Heat Recovery: GHG emissions can be dramatically reduced through heat recovery, in which a portion of the exhaust gas is recirculated to preheat the direct-fired rotary calciner feed air. Without this heat recovery, a much greater proportion of the process heat input would be lost in the exhaust gas stream, and the required heat input of these units would be substantially larger than the proposed 60 MMBtu/hour burner rating in order to achieve equal production rates. Without heat recovery on the direct-fired rotary calciners, it is estimated that burner sizing would need to be approximately 120 MMBtu/hr or approximately 2 times larger. This heat recovery mechanism will be used on all of the calcining units at Millen, as it is highly cost effective on the basis of reduced fuel consumption and also a highly effective means to reduce greenhouse gas emissions of these units.

Efficient Process Design and Optimization: The proposed lines at Millen will incorporate a number of design features and work practices that ensure that they operate at maximum efficiency. In doing so, the efficiency of the process is maximized, which limits emissions and ensures that the amount of production for a given level of emissions is maximized. This group of technologies and practices includes the following measures:

The facility will utilize several process design features to maximize its energy efficiency. First, the facility's process design is most equivalent to the precalciner type cement kiln, which has been identified the most energy efficient architecture for cement kilns.[8] Secondly, air mixing technology can be used to reduce stratification of air in a cement kiln, which improves the efficiency of the process. Feed material and air are mixed by baffles in facility's direct-fired rotary calciners, which limits the degree of stratification possible in the proposed direct-fired rotary calciners. Third, hot surfaces throughout the production process are a significant source of heat loss from cement kilns and preheaters. Similarly, the Millen facility's direct-fired rotary calciners and associated ductwork are subject to potentially large heat losses. Refractory material in the direct-fired rotary calciners is selected for proper insulating capacity and operating life. Associated ductwork and process surfaces are insulated where feasible to eliminate unintended heat losses through these surfaces.

The facility will also use several substantial work practices that maximize its energy efficiency and therefore limit GHG emissions. First, the facility will utilize extensive electronic process management and control systems to ensure that the process runs in an optimized state at all times, thereby minimizing waste and energy consumption.

[8] Available and Emerging Technologies For Reducing Greenhouse Gas Emissions from the Portland Cement Industry. U.S. EPA, Office of Air and Radiation, October 2010. No EPA Document ID number provided.

Second, good maintenance practices will be observed to ensure that the facility's direct-fired rotary calciner seals are maintained to a proper level of functionality. This practice limits heat loss and penetration of unwanted excess air into the direct-fired rotary calciner system. Third, the facility will be subjected to whole-facility benchmarking, which entails comparing the energy efficiency of manufacturing facilities. However, as few comparable facilities exist outside of the company whole-facility benchmarking becomes difficult as no such data for other comparable facilities is publically available. Notwithstanding these variabilities, CARBO conducts ongoing internal analysis of the energy efficiency of each of its facilities in continuously evaluating opportunities for energy efficiency improvements and does make comparisons of the relative efficiency of each facility. The proposed Processing Lines 1 – 4 will incorporate its experience in operating existing lines and other similar processes at other company-owned facilities. These new lines will incorporate the best features of these comparable facilities and will include those measures found to be cost-effective within the company.

<u>Good Combustion Practices:</u> As with any combustion equipment, the combustion efficiency of kilns can be optimized by ensuring proper fuel-air mixing, complete combustion of the fuel, and proper adjustment of combustion. The direct-fired rotary calciners will be maintained and operated to ensure they operate at peak efficiency.

<u>Step 2: Eliminate Technically infeasible options</u>

Option 1 – Fluxes/Mineralizers to Reduce Required Kiln Temperature

The use of fluxes and mineralizers applicable to the Portland cement industry is not applicable to the production of ceramic proppants. CARBO is not aware of any practical means to reduce the necessary kiln temperature required for the production of ceramic proppants with the required properties. As such, this option will not be considered further in this analysis.

Option 2 – Raw Material Substitution

Unlike the Portland cement process, the proposed kilns do not use feedstocks that result in process-related CO_2 emissions; all GHG emissions from the direct-fired rotary calciners will be from fuel combustion itself. As there are no known alternate raw materials that reduce the GHG emissions from this process, this option will not be considered further in this analysis.

Option 3 – Carbon Capture and Sequestration (CCS)

CCS technologies at this stage are only considered "available" for large CO_2-emitting facilities such as large fossil-fueled power plants and industrial facilities with exhaust streams of high-purity CO_2.[9] Based on the discussion of CCS capture mechanisms in the White Paper on Portland cement, the application of these mechanisms to Portland cement

[9] PSD and Title V Permitting Guidance for Greenhouse Gases. U.S. EPA, Office of Air and Radiation, November 2010, at p. 33. No EPA Document ID available.

production is still in an early research phase and has not been tested in practice. As Portland cement production is more prevalent than manufacturing of kaolin-based ceramic proppants, far less is known and/or understood regarding the feasibility and applicability of these technologies to the proposed direct-fired rotary calciners. Therefore, CCS will not be considered further in this analysis as it is not considered available and technically feasible for the type of opeations at the proposed facility.

Option 4 – Fuel Switching

The proposed Direct-fired Rotary Calciner Nos. 1 – 4 are designed to be fired exclusively by natural gas and LPG (propane). These fuels are the least carbon-intensive of all readily available fossil fuels,[10] and no practical non-fossil gaseous fuels are readily available. Therefore, no further benefit is available by switching to alternative fuels, and this option will not be considered further in this analysis.

<u>Step 3: Rank remaining control technologies by control effectiveness</u>

Table F.1-2: Ranking of Control Technology

Control Technology Ranking	Option No.	Control Technology	Control Efficiency
1	5	Baseline Control Measures	N/A

<u>Step 4: Evaluate most effective controls and document results</u>

Detailed analysis of the energy, environmental, and economic impacts of the remaining control technologies is omitted from this analysis, as the facility is implementing the only remaining control option as BACT for Direct Fired Calciner Nos. 1 – 4. These control measures are voluntarily stipulated as cost-effective for this unit.

<u>Step 5: Select BACT</u>

Table F.1-3 below summarizes the BACT determination being proposed for the four Direct-fired Rotary Calciners.

Table F.1-3: GHG BACT Proposed for Direct-fired Rotary Calciner Nos. 1 – 4

Emission Unit ID Nos.	Proposed BACT
KLN1 – KLN4	Limiting GHG emissions to 36,715 tpy CO_2e per Calciner through the use of the following technologies and practices: • Reject Heat Recovery • Efficient Process Design and Optimization • Good Combustion Practices

[10] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2008. U.S. EPA Document 430-R/10-006, April 2010, at page 3-4

The utilization of Reject Heat Recovery, Efficient Process Design and Optimization , and Good Combustion Practices with an emissions limitation of 36,715 tpy CO_2e from each Calciner (Emission Unit ID Nos. KLN1 – KLN4) is proposed as BACT.

F.2 GHG Review: Spray Dryer Nos. 1 – 8

Greenhouse gases (GHG) including CO_2, N_2O, and CH_4 are emitted from the Spray Dryers due to the combustion of natural gas. In the Millen facility's process, spray dryers not only dry the kaolin slurry, they also critically prepare the processed material with characteristics necessary to optimize the eventual end product prior to calcining.

Baseline GHG emissions for the spray dryers of approximately 28,760 tpy CO_2e are calculated based on AP-42 emission factors for external combustion of natural gas.[11] The facility will utilize a number of practices (to be discussed in further detail later) to ensure optimum energy efficiency and GHG emission minimization for the proposed spray dryers. These include the following types of practices:

- Efficient Process Design and Optimization
- Good Combustion System Design and Optimization

Step 1: Identify all control technologies

At this early stage of regulation of GHG as an NSR pollutant, the number of available control technology determinations and developed guidance on what constitutes BACT for GHG for any emission unit type is extremely limited. This situation is compounded by the fact that while spray dryers are generally a common process, the proposed spray dryers are essentially unique in terms of their design and functionality beyond simply drying slurry. As such, there is virtually no precedent for controlling GHG emissions from these units. However, US EPA has provided a white paper on technologies to reduce GHG emissions from the Portland cement industry- "Available and Emerging Technologies For Reducing Greenhouse Gas Emissions from the Portland Cement Industry".[12] While there are substantial operational differences between Portland cement manufacturing and ceramic proppant manufacturing, there are also some basic similarities. To the extent that the related processes are similar, guidance applicable to the Portland cement industry in this document (the "White Paper") is of some use in establishing technologies which are relevant for consideration as controls for the proposed spray dryers.

It should be noted, though, that the White Paper explicitly states that it is not setting a policy on what constitutes BACT for the Portland cement industry; however, it identifies a large number of potentially applicable technologies that could be considered in a GHG BACT analysis for that industry. As such, it can be applied to spray drying of ceramic proppants on a general basis. Thus, this analysis will consider the technologies proposed in the White Paper that are relevant to ceramic proppant spray dryers.

This analysis also requires a somewhat different approach than typical PSD BACT analyses in that a larger number of control technologies are considered, and many of those control technologies are mutually complementary. Also note that, in accordance

[11] AP-42 Compilation of Emission Factors, 5th Edition, U.S. EPA OAQPS, January 1995, Chapter 1.4, Table 1.4-2.

[12] Available and Emerging Technologies For Reducing Greenhouse Gas Emissions from the Portland Cement Industry. U.S. EPA, Office of Air and Radiation, October 2010. No EPA Document ID number provided.

with the Guidance, this Step 1 analysis considers only those control options relevant for reducing on-site GHG emissions.

Table F.2-1 below summarizes the control technologies considered for the spray dryers.

Table F.2-1: Evaluated Control Options for GHG Emissions – Spray Dryers (SD01 – SD08)

Option No.	Control Technology
1	Raw Material Substitution
2	Carbon Capture and Sequestration (CCS)
3	Fuel Switching
4	Baseline Control Measures

Option 1 – Raw Material Substitution

Portland cement processes can use blend in substitute feedstocks such as fly ash to reduce the amount of raw material needed to make a given quantity of clinker. This is relevant in Portland cement production because there are process-related CO_2 emissions in addition to those from the fuel combustion itself; these emissions are from the calcination reaction of calcium carbonate from limestone, which dissociates into CO_2 and calcium oxide. To the extent that these substitute feedstocks displace usage of calcium carbonate that contributes to the process-related CO_2 emissions, the substitution decreases GHG emissions from the process.

Option 2 – Carbon Capture and Sequestration (CCS)

CCS in its simplest application provides the mechanism for carbon in the exhaust gas stream to be captured prior to being emitted to the atmosphere and is permanently stored or utilized for some other non-emissive purpose. There are a number of methods by which these systems work, but the functional mechanism and details are relatively unimportant for the purpose of this analysis.

Option 3 – Fuel Switching

For a given value of heat supplied, there is variation in the CO_2 emissions expected from each fuel. Among fossil fuels, coal has the highest carbon intensity[13] (i.e. the highest CO_2 emissions for a given amount of heat supplied), and natural gas has the lowest carbon intensity. As such, a combustion source can sometimes reduce its GHG emissions by switching from a relatively more carbon intensive fuel, such as coal, to one with lower carbon intensity, such as oil or natural gas.

[13] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2008. U.S. EPA Document 430-R/10-006, April 2010, at page 3-4

Option 4 – Baseline Control Measures

As described previously, the facility plans to use a number of practices to optimize its energy efficiency and minimize its GHG emissions. These include measures in the following general categories:

- Efficient Process Design and Optimization
- Good Combustion System Design and Optimization

Efficient Process Design and Optimization: The proposed lines at Millen will incorporate a number of design features and work practices that ensure that they operate at maximum efficiency. In doing so, the efficiency of the process is maximized, which limits emissions and ensures that the amount of production for a given level of emissions is maximized. This group of technologies and practices includes the following measures:

First, the Millen facility's spray dryers and associated ductwork are subject to potentially large heat losses. Associated ductwork and process surfaces on the spray dryers are insulated where feasible to eliminate unintended heat losses through these surfaces. Second, the proposed lines at Millen utilize extensive electronic process management and control systems to ensure that the process runs in an optimized state at all times, thereby minimizing waste and energy consumption. Third, the White Paper suggests that improvements in the sorting efficiency of classifiers would reduce the amount of feed that is returned for reprocessing, allowing a greater proportion of the feed to continue on directly to firing in the kiln or calciner. By reducing the amount of feed that has to be reprocessed, the energy required for repeat spray drying of the same material would be reduced. The facility will select high-efficiency classifiers to minimize feed that is in fact at within the desired size range but is rejected and recycled for reprocessing.

Fourth, the facility will be subjected to whole-facility benchmarking, which entails comparing the energy efficiency of manufacturing facilities. However, as few comparable facilities exist outside of the company whole-facility benchmarking becomes difficult as no such data for other comparable facilities is publically available. Notwithstanding these variabilities, CARBO conducts ongoing internal analysis of the energy efficiency of each of its facilities in continuously evaluating opportunities for energy efficiency improvements and does make comparisons of the relative efficiency of each facility. The proposed lines 1 – 4 will incorporate its experience in operating existing lines and other similar processes at other company-owned facilities. These new lines will incorporate the best features of these comparable facilities and will include those measures found to be cost-effective within the company.

Good Combustion Practices: As with any combustion equipment, the combustion efficiency of spray dryers can be optimized by ensuring proper fuel-air mixing, complete combustion of the fuel, and proper adjustment of combustion. The spray dryer systems will be maintained and operated to ensure they operate at peak efficiency.

Step 2: Eliminate Technically infeasible options

Option 1 – Raw Material Substitution

Unlike the Portland cement process, the proposed spray dryers do not use feedstocks that result in process-related CO_2 emissions; all GHG emissions from the spray dryers will be from fuel combustion itself. As there are no known alternate raw materials that reduce the GHG emissions from this process, this option will not be considered further in this analysis.

Option 2 – Carbon Capture and Sequestration (CCS)

CCS technologies at this stage are only considered "available" for large CO_2-emitting facilities such as large fossil-fueled power plants and industrial facilities with exhaust streams of high-purity CO_2.[14] Based on the discussion of CCS capture mechanisms in the White Paper on Portland cement, the application of these mechanisms to Portland cement production is still in an early research phase and has not been tested in practice.. As Portland cement production is more common than production of kaolin-based ceramic proppants, far less is known and/or understood regarding the feasibility and applicability of these technologies to the proposed spray dryers. Therefore, CCS will not be considered further in this analysis.

Option 3 – Fuel Switching

The proposed Spray Dryers 1 – 8 are designed to be fired exclusively by natural gas and LPG (propane). These fuels are the least carbon-intensive of all readily available fossil fuels,[15] and no practical non-fossil gaseous fuels are readily available. Therefore, no further benefit is available by switching to alternative fuels, and this option will not be considered further in this analysis.

Step 3: Rank remaining control technologies by control effectiveness

Table F.2-2: Ranking of Control Technology

Control Technology Ranking	Option No.	Control Technology	Control Efficiency
1	4	Baseline Control Measures	N/A

Step 4: Evaluate most effective controls and document results

Detailed analysis of the energy, environmental, and economic impacts of the remaining control technologies is omitted from this analysis, as the facility is implementing the only

[14] PSD and Title V Permitting Guidance for Greenhouse Gases. U.S. EPA, Office of Air and Radiation, November 2010, at p. 33. No EPA Document ID available.
[15] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2008. U.S. EPA Document 430-R/10-006, April 2010, at page 3-4

remaining control option as BACT for Spray Dryers 1 – 8. These control measures are voluntarily stipulated as cost-effective for this unit.

Step 5: Select BACT

Table F.2-3 below summarizes the BACT determination requirements being proposed for the eight spray dryers.

Table F.2-3: GHG BACT Proposed for Spray Dryer Nos. 1 – 8

Emission Unit ID Nos.	Proposed BACT
SD01 – SD08	Limiting GHG emissions to 28,760 tpy CO_2e per Spray Dryer through the use of the following technologies and practices: • Efficient Process Design and Optimization • Good Combustion Practices

The utilization of Efficient Process Design and Optimization and Good Combustion Practices with an emissions limitation of 28,760 tpy CO_2e from each Spray Dryer (Emission Unit ID Nos. SD01 – SD08) is proposed as BACT.

F.3 GHG Review: Gas Fired Boiler Nos. 1 – 4

Greenhouse gases including CO_2, N_2O, and CH_4 are emitted from Gas Fired Boiler Nos. 1 – 4 as a result of fossil fuel combustion. CO_2 is produced through the combustion reaction itself, wherein the carbon content of the fuel reacts with oxygen from the combustion air. N_2O is formed during fuel combustion through the same mechanisms that result in NO_x formation. Any CH_4 emissions from these units would be uncombusted fuel. As the primary contributor to overall greenhouse gas emissions from combustion of fossil fuels is the CO_2 component, BACT for GHG emissions from this type of process will focus primarily on CO_2 reductions via improvements in the thermal efficiency of the process.

Baseline: The primary fueling of these small units (Boiler Nos. 1 – 4 are each less than 10 MMBtu/hour) with natural gas, with LPG (propane) as a back-up fuel, provides a low starting point for baseline emissions. Natural gas has only 55% the carbon content of coal per unit of energy,[16] and therefore produces lower CO_2 emissions per unit of energy by that same differential.[17] Additionally, the proposed boilers are to be new and as such will include the latest design features for minimizing overall pollutant emissions and achieving high thermal efficiency. These boilers are tentatively proposed to be of the Cleaver-Brooks CBLE series (or equivalent) dryback firetube boilers, and as such will include a number of design features that specifically increase their energy efficiency and thus reduce GHG emissions. These are expected to include:

- Four pass design with over 5 square feet of fire-side heat exchange surface per boiler horsepower
- Parallel positioning control for natural gas, combustion air, and FGR flow rates
- Burner design that maximizes efficiency while maintaining compatibility with low NO_x emissions design

As new boilers, they can also be expected to be installed in good working order, with a minimum of excess air and air infiltration, new burners, and proper insulation and refractory materials. The overall effect of these design features allow for a manufacturer's fuel-to-steam energy efficiency specification of 82.7% at 25% load, 82.6% at 50% load, 82.1% at 75% load, and 81.7% at full load. The baseline also includes a variety of efficiency-related work practices to be described in further detail below.

<u>Step 1: Identify all control technologies</u>

At this early stage of regulation of GHG as an NSR pollutant, the number of available control technology determinations and amount of guidance on what constitutes BACT for GHG is extremely limited. The one entry found in US EPA's RBLC database for controls of any greenhouse gas from a boiler was listed as being for CO_2 emissions, but on closer examination appears to be a typographical error and actually pertains to CO emissions. However, US EPA has provided a white paper on technologies to reduce GHG emissions from boilers- "Available and Emerging Technologies For Reducing Greenhouse Gas

[16] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2008. U.S. EPA Document 430-R/10-006, April 2010, at page 3-4.

[17] Available and Emerging Technologies For Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers. U.S. EPA, Office of Air and Radiation, October 2010. No EPA Document ID number provided.

Emissions from Industrial, Commercial, and Institutional Boilers".[18] This document (the "White Paper") is explicitly described as not setting a policy on what constitutes BACT for such units; however, it identifies a large number of potentially applicable technologies that could be considered in a GHG BACT analysis for boilers. Table F.3-1 below identifies the relevant technologies to be evaluated.

Table F.3-1: Evaluated Control Options for GHG Emissions – Gas Fired Boiler Nos. 1 – 4

Option No.	Control Technology
1	Carbon Capture and Sequestration (CCS)
2	Biomass Firing/Co-Firing
3	Fuel Switching
4	Firetube Turbulators
5	Baseline Control Measures

Option 1 – Carbon Capture and Sequestration (CCS)

CCS in its simplest sense simply means that the carbon in the exhaust gas stream is captured prior to being emitted to the atmosphere and is permanently stored or used for some other non-emissive purpose. There are a number of methods by which these systems work, but the functional mechanism is unimportant for the purpose of this analysis.

Option 2 – Biomass Firing/Co-Firing

The use of biomass in place of fossil fuels does not reduce the direct GHG emissions of a combustion unit. However, the biomass to be combusted would have been produced via photosynthesis, whereby plants absorb CO_2 from the atmosphere and release oxygen. This process is essentially reversed at the point of combustion of the biofuel, and the amount of CO_2 released is equal to the amount taken up by the plant matter during photosynthesis. This process can be repeated endlessly in a renewable cycle. There are two major sources of biomass now in use in combustion units: solid biomass and biogas.

Option 3 – Fuel Switching

The proposed Boiler Nos. 1 – 4 are designed to be fired exclusively by natural gas and LPG (propane). These fuels are already the least carbon-intensive of all readily available fossil fuels,[19] and no practical non-fossil gaseous fuels are readily available. Therefore, no further benefit is available by switching to alternative fuels.

Option 4 – Turbulators for Firetube Boilers

Turbulators improve the efficiency of existing boiler heat exchange surfaces, typically in the last pass of the heat exchanger. Turbulators break up laminar flow in the heat

[18] Available and Emerging Technologies For Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers. U.S. EPA, Office of Air and Radiation, October 2010. No EPA Document ID number provided.

[19] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2008. U.S. EPA Document 430-R/10-006, April 2010, at page 3-4

exchanger to prevent formation of a cooler boundary layer of gases along the heat exchange surfaces. While turbulators are a lower-cost alternative to economizers or air preheaters, they are most applicable to older boilers with relatively small heat exchange surfaces. New boilers with additional heat exchanger surface extract more energy than such older boilers, and as such there is much less additional energy to be captured using this method in efficient new boilers.

Option 5 – Baseline Control Measures

The following additional control measures are voluntarily stipulated to be cost-effective measures for maximizing the energy efficiency of the process. These practices are included in the package of baseline control measures relative to which other control options will be evaluated.

- Four pass design with over 5 square feet of fire-side heat exchange surface per boiler horsepower
- Parallel positioning control for natural gas, combustion air, and FGR flow rates
- Burner design that maximizes efficiency while maintaining compatibility with ultra-low NO_x emissions design

Good O&M Practices: Good operating and maintenance practices are used to minimize the gradual reduction in efficiency that boilers naturally experience over time. These practices ensure that combustion efficiency is optimized by ensuring proper fuel-air mixing, minimizing excess air, sealing air leaks, cleaning heat exchange surfaces of deposits, etc.

Good Steam Line Maintenance Practices: Steam traps require ongoing maintenance to prevent steam leaks. Steam supply lines, condensate return lines, steam traps, and all associated fitting should be insulated if they would exceed 120ºF without insulation.

Burner Design: Specifying a burner allowing for the lowest possible rates of excess air will maximize the energy efficiency of a boiler throughout its operational range. Careful burner sizing to minimize excess capacity will reduce the amount of turndown and on-off cycling required under low-load conditions, which will improve real-world fuel efficiency.

Combustion Tuning and Optimization: Combustion tuning is used to maximize the efficiency of burner operation, and may be performed periodically in order to ensure that the burner configuration is at its optimum. Electronic optimization systems are sometimes used on large boilers subject to dynamic operating conditions in order to continuously perform such tuning; this is particularly the case for units subject to variability in fuel characteristics.

Condensate Return: For the portion of the steam output of these units that is used on a closed-loop basis, such as in heat exchangers, the used steam is condensed and returned to the boiler for re-use.[20] Less heat is required to re-heat hot condensate to the saturated steam temperature than if the condensate were not returned and was

[20] Some boiler steam is used for direct injection into the process on an open-loop basis and cannot be recovered.

instead replaced by cold boiler make-up water. Additionally, the reduction in make-up water requirements reduces the amount of dissolved minerals entering the system, which reduces the need for blowdown from the boiler, which wastes boiling water to purge this mineral content.

<u>Insulation:</u> Improving insulation on boiler surfaces and pipes that deliver hot water or steam reduce unwanted heat loss, which allows for reduced boiler load with the same amount of heat delivered to the process. This is especially important for small units, and for larger units operating at lower load. In these cases, radiative losses can be as high as 7%.

Insulation is typically added to heated surfaces that would exceed 120ºF without insulation, except when safety or process related reasons make it impossible to insulate the particular surfaces.

These practices are in addition to the fueling of the units exclusively with natural gas and LPG (propane), with LPG used only as a back-up fuel. Natural gas has the lowest carbon content of the traditional fossil fuels, and results in only 55% the greenhouse gas emissions that would be expected from a coal-fired boiler.

<u>Step 2: Eliminate Technically infeasible options</u>

Option 1 – Carbon Capture and Sequestration (CCS)

CCS technologies are at this stage only considered "available" for large CO_2-emitting facilities such as large fossil-fueled power plants and industrial facilities with exhaust streams of high-purity CO_2.[21] There is no indication that such technologies have been demonstrated in practice in a production environment on a small natural gas-fired boiler, nor are these technologies applicable to such sources in any pratical sense. Therefore, CCS will not be considered further in this analysis.

Option 2 – Biomass Firing/Co-Firing

There are a number of drawbacks and limitations to biomass fuels, however. Solid biomass is only compatible with units that can process solid fuels, and other than SO_2, criteria pollutant emissions are comparable to coal firing. Additionally, combustion of solid biomass often creates solid deposits inside boilers, which reduce heat transfer efficiency and are difficult to remove. The proposed Boiler Nos. 1 – 4 are designed to be fired exclusively by gaseous fuels. As there are no significant sources of biogas in the area, solid biomass firing is not feasible in this application.

Biogas is compatible with units designed to combust gaseous fuels, but typically requires specialized burners designed to handle its low heating value (often 500 Btu/scf or lower, compared to 1,020 Btu/scf for natural gas). Criteria pollutant emissions from biogas are nearly comparable to that of natural gas, but some degree of pretreatment may be needed.

[21] PSD and Title V Permitting Guidance for Greenhouse Gases. U.S. EPA, Office of Air and Radiation, November 2010, at p. 33. No EPA Document ID available.

Additionally, practical biogas availability is limited to areas near landfills because of the need for distribution pipelines, and in many cases, the entire biogas production of landfills has already been sold to neighboring facilities for combustion in their fuel-burning equipment or is combusted at the landfill for power generation.

Option 3 – Fuel Switching

The proposed Boiler Nos. 1 – 4 are designed to be fired exclusively by natural gas and LPG (propane). These fuels are already the least carbon-intensive of all readily available fossil fuels,[22] and no practical non-fossil gaseous fuels are readily available. Therefore, no further benefit is available by switching to alternative fuels.

Option 4 – Turbulators for Firetube Boilers

Turbulators are typically considered only as a retrofit to existing, older boilers with limited heat exchange surface area. A new boiler is designed as a system for optimum energy efficiency and overall emissions minimization. The proposed boilers already use four heat exchange passes to maximize the amount of heat extracted from the flue gas. As such, minimal additional heat exchange is possible using this mechanism, and that minimal benefit is countervailed by the small increase in power consumption necessary to overcome the pressure drop the turbulators create.

Step 3: Rank remaining control technologies by control effectiveness

Table F.3-2: Ranking of Control Technology

Control Technology Ranking	Option No.	Control Technology	Control Efficiency
1	5	Baseline Control Measures	N/A

Step 4: Evaluate most effective controls and document results

Detailed analysis of the energy, environmental, and economic impacts of the remaining control technologies is omitted from this analysis, as the facility is implementing the only remaining control option as BACT for Gas-fired Boilers 1 – 4. These control measures are considered cost-effective for this unit.

Step 5: Select BACT

Table F.3-3 summarizes the BACT determination requirements being proposed for the four boilers.

[22] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2008. U.S. EPA Document 430-R/10-006, April 2010, at page 3-4

Table F.3-3: GHG BACT Proposed for Boiler Nos. 1 – 4

Emission Unit ID Nos.	Proposed BACT
BLR1 – BLR4	Limiting GHG emissions to 5,997 tpy CO_2e per Boiler through the use of the following technologies and practices: • Exclusive use of natural gas and propane as fuels • Efficient boiler design, operation, and maintenance practices • Insulation of boiler-heated surfaces

The exclusive use of Natural Gas and Propane, Insulation of boiler-heated surfaces, and efficient boiler design, operation, and maintenance practices with an emissions limitation of 5,997 tpy CO_2e from each Boiler (Emission Unit ID Nos. BLR1 – BLR4) is proposed as BACT.

F.4 GHG Review: Emergency Generator Nos. 1 – 4

The facility is proposing to install four (4) diesel fired emergency generators driven by diesel engines rated at 3,058 horsepower each. These emergency generators are necessary support equipment for the new process direct-fired rotary calciners. The proposed generators are to be rated at approximately 2,000 kW electrical output each. GHGs are emitted from the emergency generators due to the internal combustion of diesel fuel. These generators are critical equipment necessary to the operation of the facility based on the risk to the refractory lining of the direct-fired rotary calciners during a power outage. If for any reason conditions within the direct-fired rotary calciners change suddenly, such as from an interruption in burner or fan operation, the refractory lining will be destroyed. Replacement of the refractory in response to such an event, when considering the material and labor cost of refractory replacement and the extensive downtime such a disaster would cost several million dollars. As such, it is not only imperative that the facility have an emergency generator for each direct-fired rotary calciner, it is imperative that these units be maintained in top condition so that they are guaranteed to start when needed.

Baseline GHG emissions for the each emergency generator of approximately 844 tpy CO_2e (assuming 500 operating hours per year) are calculated based on AP-42 emission factors for large internal combustion diesel engines,[23] and are based upon the use of efficient design and operational practices to limit GHG emissions from these units. These practices will include the use of good maintenance practices to ensure that the engine operates as designed; and a practically enforceable permit condition limiting these units to 500 hours of operation per year.

<u>Step 1: Identify all control technologies</u>

At this early stage of regulation of GHG as an NSR pollutant, the number of available control technology determinations and amount of guidance on what constitutes BACT for GHG is extremely limited. The only two entries found in US EPA's RBLC database for controls of any greenhouse gas from a reciprocating engine appear to be a result of typographical errors.[24, 25] However, some of the technologies evaluated for the GHG BACT analysis for boilers, which precede this analysis, could be applicable to these emergency generators, and will be considered here to the extent feasible.

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[23] AP-42 Compilation of Emission Factors, 5th Edition, U.S. EPA OAQPS, January 1995, Chapter 3.4, Table 3.4-1 and 40 CFR Part 98, Table C-2

[24] RBLC Entry TX-0481 for Air Products, L.P.'s Emergency Generator has an emission limit listed for CO2 emissions, but on closer examination this appears to be a typographical error and actually pertains to CO emissions.

[25] RBLC Entry MD-0040 for Competitive Power Ventures, Inc.'s Emergency Fire Water Pump has an emission limit listed for CH_4 emissions, but on closer examination the emission limit is unreasonably high (3.0 g/HP-hr) and equal to the limit listed for NO_x. Given that this limit was for a permit issued in 2008 and pertains to a small piece of ancillary equipment at proposed new natural gas fired power plant, it is believed to be in error and not an extremely early effort at limiting GHG emissions.

Table F.4-1: Evaluated Control Options for GHG Emissions – Emergency Generator Nos. 1 – 4

Option No.	Control Technology
1	Carbon Capture and Sequestration (CCS)
2	Biomass Firing/Co-Firing
3	Fuel Switching
4	Waste Heat Recovery
5	Efficient Design and Operational Practices

Option 1 – Carbon Capture and Sequestration (CCS)

CCS in its simplest sense simply means that the carbon in the exhaust gas stream is captured prior to being emitted to the atmosphere and is permanently stored or used for some other non-emissive purpose. There are a number of methods by which these systems work, but the functional mechanism is unimportant for the purpose of this analysis.

Option 2 – Biomass Firing/Co-Firing

The use of biomass in place of fossil fuels does not reduce the direct GHG emissions of a combustion unit. However, the biomass to be combusted would have been produced via photosynthesis, whereby plants absorb CO_2 from the atmosphere and release oxygen. This process is essentially reversed at the point of combustion of the biofuel, and the amount of CO_2 released is equal to the amount taken up by the plant matter during photosynthesis. This process can be repeated endlessly in a renewable cycle. There are two major sources of biomass now in use in large stationary internal combustion engines: biodiesel and biogas. Biogas is typically landfill gas. Landfill gas contains a number of byproducts of decomposition, including methane and VOCs. This gas was traditionally vented to the atmosphere or flared to address odor concerns. The gas has sufficient fuel value for use in boilers and reciprocating engines, however. Combusting landfill gas has a number of major advantages over venting. First, the carbon is released to the atmosphere as CO_2, with a global warming potential (GWP) of 1, instead of as CH_4, with a GWP of 21. This reduces the global warming effect of the carbon emission by 95% (1/21). Second, the combustion of the landfill gas can do useful work, which typically displaces demand for fossil fuels and emissions of fossil carbon. Biodiesel is a liquid fuel with properties similar to conventional (petroleum) diesel fuel, but is produced by transesterification of vegetable oil or animal fats. Biodiesel is becoming available in the marketplace, though at a price premium relative to petroleum-derived diesel fuels.

Option 3 – Fuel Switching

The carbon intensity of various fossil fuels varies. As such, for a given level of output, carbon emissions can be reduced in some cases by switching to a fuel with lower carbon content. The proposed Emergency Generator Nos. 1 – 4 are designed to be fired exclusively by diesel fuel. Alternative engine designs are available that could reduce the GHG emissions of these generators by switching to an engine designed to combust pure natural gas or a dual fuel engine that combusts primarily natural gas, with a small amount of diesel fuel used as a combustion initator. For example, the AP-42 emission factors for large stationary internal combustion engines imply that a 33% reduction in CO_2 emissions could be obtained by switching to such a dual fuel arrangement.[26]

Option 4 – Waste Heat Recovery

Operation of the emergency generator engine produces waste heat, which is normally dissipated through its hot exhaust gas, its water-to-air cooling system, and directly to the air surrounding the engine via radiative, convective, and conductive mechanisms. Additionally, the alternator that produces emergency power from the engine's mechanical output is air-cooled and also produces significant waste heat during operation. Heat could be recovered from one or more of these sources and used for other nearby purposes requiring low-temperature waste heat, in the case of heat rejected by the engine's alternator or cooling system. The higher temperature of the engine exhaust, which can reach 869ºF under design conditions, offers some opportunity for production of high-temperature steam.

Step 2: Eliminate Technically infeasible options

Option 1 – Carbon Capture and Sequestration (CCS)

CCS technologies are at this stage only considered "available" for large CO_2-emitting facilities such as large fossil-fueled power plants and industrial facilities with exhaust streams of high-purity CO_2.[27] There is no indication that such technologies have been demonstrated in practice in a production environment on a small natural gas-fired boiler, nor are these technologies applicable to such sources in any pratical sense. Therefore, CCS will not be considered further in this analysis.

Option 2 – Biomass Firing/Co-Firing

Biogas is compatible with units designed to combust gaseous fuels such as natural gas, but typically requires some adjustment and de-rating based on its low heating value (often 500 Btu/scf or lower, compared to 1,020 Btu/scf for natural gas). Criteria pollutant emissions from biogas are nearly comparable to that of natural gas, but some degree of pretreatment may be needed. Additionally, practical biogas availability is limited to areas near landfills because of the need for distribution by pipeline, and in many cases, the entire biogas production of landfills has already been sold to neighboring facilities for combustion in their fuel-burning equipment or is combusted at the landfill for power generation. As there are no adequate sources of biogas within a practical radius for piping to these emergency generators, biogas firing will not be considered further in this analysis.

[26] U.S. EPA's AP-42 Compilation of Emission Factors, Chapter 3.4, Table 3.4-1; CO_2 emission factor is 1.16 lb/hp-hr for diesel fuel and 0.772 lb/hp-hr for dual fuel

[27] PSD and Title V Permitting Guidance for Greenhouse Gases. U.S. EPA, Office of Air and Radiation, November 2010, at p. 33. No EPA Document ID available.

Biodiesel is easier to transport to the facility, but poses operational problems that have been widely observed in its use in mobile diesel engines. Biodiesel gels at ambient temperatures commonly found in Georgia winters, which means that fuel tank heating would be required to maintain the fuel in a usable liquid state during cold weather. Biodiesel is a relatively hospitable environment for microbial growth, especially when at high concentrations and when stored for long periods. Such microbial growth can clog fuel filters and/or otherwise cause engine damage or failure during the emergency conditions in which it is needed. Biodiesel also does not offer the same lubricating properties offered by petroleum diesel. These lubricating properties are required by critical and expensive engine components such as the high-pressure fuel pump. For this reason, many diesel engine manufacturers specify a limit of 5% biodiesel fueling (i.e. a blend of 95% conventional diesel and 5% biodiesel). As emergency generators are particularly vulnerable to the risk of microbial growth and based on the tremendous economic cost of a breakdown or failure to start of one of these generators when needed, CARBO considers the risks posed by biodiesel co-firing in these units to be excessive and disproportionate to the small environmental benefit.

Option 3 – Fuel Switching

Like many major industrial consumers of natural gas, the facility has “interruptible” natural gas service. In this arrangement, the consumer is required to curtail (cease) natural gas usage upon request by the supplier during natural gas supply or distribution emergencies. These curtailments have typically occurred during periods of unusually cold weather or during natural disasters that disrupt production and distribution equipment. Cold weather curtailments occur when demand for natural gas for space heating spikes so dramatically that it outstrips the capacity of the distribution system to meet demand in the area. To preserve the integrity of the distribution system and ensure that retail and commercial customers do not go without comfort heating, large industrial users curtail their demand. Natural disasters such as Hurricane Katrina have also occasionally caused disruptions to natural gas production and distribution processes to the extent that widespread curtailment of nonessential natural gas usage occurred. Like many facilities with interruptible natural gas service, the facility maintains a backup supply of LPG (propane) that can be used in place of natural gas during the curtailment. However, the LPG supply during these conditions is severely constrained by two factors.

Firstly, because of the cost and safety concerns of stockpiling large amounts of LPG, the facility’s storage capacity is limited to a supply adequate to ensure that the kilns can make an orderly shut-down in response to a natural gas curtailment. The system is not sized to allow for long-term continued operation on stored LPG. Additionally, distributors of LPG maintain a truck fleet and storage capacity adequate only for everyday needs. When a natural gas curtailment takes place, it is virtually impossible to obtain or have delivered large quantities of LPG as would be necessary to maintain continued operation of the plant, either because severe cold weather has increased demand for LPG for space heating, because other industries with interruptible natural gas service are also rushing to buy LPG, or both.

Secondly, LPG is stored in liquid form but used in gaseous form. However, in gaseous form its pressure and HHV are different from natural gas. To eliminate the need to maintain two sets of burners in every piece of fuel-burning equipment at the facility, special equipment at the facility vaporizes the LPG and mixes it with air in order to make a blended gas that can be used directly by equipment designed for natural gas. This equipment is also capacity constrained with respect to the rate at which it can make this substitute gas.

Both of these factors limit the practicality of using natural gas-fired or dual-fuel emergency generators at the facility, as the emergency generators cannot serve their intended purpose when operating on an interruptible fuel without backup. As such, fuel switching to natural gas would require dramatically up-sizing the LPG storage and vaporization equipment at the facility, and also increase the risk posed by LPG explosion by increasing the amount of LPG stored at the facility. These factors are disproportionate relative to the small GHG emission benefit possible by fuel switching, especially in the context of units with a pratically enforceable limit of 500 operating hours per year.

Option 4 – Waste Heat Recovery

Given that these units are emergency generators and are being proposed with a 500 hour per year limit on operation, they will operate only intermittently in short and sporadic bursts. Given the tremendous size and mass of each engine, the amount of heat rejected to cooling water and engine exhaust during such sporadic operation will be far below what would be expected from similar a unit subject to continuous operation. As the practical feasibility of recovering meaningful waste heat from Emergency Generator Nos. 1 – 4 is extremely limited and any such heat recovery equipment would not serve its intended purpose while operating only 500 hours per year, it is deemed technically infeasible and will not be considered further in this analysis.

Step 3: Rank remaining control technologies by control effectiveness

Table F.4-2: Ranking of Control Technology

Control Technology Ranking	Option No.	Control Technology	Control Efficiency
1	1	Efficient Design and Operational Practices	N/A

Step 4: Evaluate most effective controls and document results

The usage of Efficient Design and Operational Practices is the only remaining control option, and is the base case for this analysis.

Step 5: Select BACT

Table F.4-3 summarizes the BACT determination requirements being proposed for the emergency generators.

Table F.4-3: GHG BACT Proposed for Emergency Generator Nos. 1 – 4

Emission Unit ID Nos.	Proposed BACT
EDG1 – EDG4	Limiting GHG emissions to 844 tpy CO_2e per Emergency Generator through the use of the following technologies and practices: • Efficient Design and Operational Practices • Requirement to use good maintenance practices • Limit hours of operation to 500 hours per year each

The utilization of Efficient Design and Operational Practices and the use of Good Maintenance Practices with an emissions limitation of 844 tpy CO_2e from each Emergency Generator (Emission Unit ID Nos. EDG1 – EDG4) is proposed as BACT.

ATTACHMENT G

Electronic Disks for Volume II