



State of Idaho
Department of Environmental Quality
Air Quality Division

**AIR QUALITY PERMIT
STATEMENT OF BASIS**

Tier II Operating Permit No. T2-2009.0109

Final Permit

P4 Production, L.L.C.

Soda Springs, Idaho

Facility ID No. 029-00001

November 10, 2009

CZ
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Permit Writer

The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01. et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

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Acronyms, Units, and Chemical Nomenclature

acfm	actual cubic feet per minute
AFS	AIRS Facility Subsystem
AIRS	Aerometric Information Retrieval System
AQCR	Air Quality Control Region
ASTM	American Society for Testing and Materials
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
CAA	Clean Air Act
CAM	compliance assurance monitoring
CAS No.	Chemical Abstracts Service registry number
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
dv	deciview
EL	screening emission levels
EPA	U.S. Environmental Protection Agency
HAP	hazardous air pollutants
hr/yr	hours per year
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
km	kilometers
lb/hr	pounds per hour
LCDA	lime concentrated dual alkali
MACT	Maximum Achievable Control Technology
NAICS	North American Industry Classification System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO ₂	nitrogen dioxide
NO _x	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operations and maintenance
PC	permit condition
PM	particulate matter
PM ₁₀	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
ppm	parts per million
PSD	Prevention of Significant Deterioration
PTC	permit to construct
PTE	potential to emit
Rules	Rules for the Control of Air Pollution in Idaho
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO ₂	sulfur dioxide
SO _x	sulfur oxides
T/yr	tons per year
T2	Tier II operating permit
UTM	Universal Transverse Mercator

1. FACILITY INFORMATION

1.1 Facility Description

P4 Production operates a phosphorus production facility in Soda Springs. Coke, quartzite, phosphate ore, and clinker are brought to the site by truck or railcar. The coke and quartzite are dried, if needed, and screened. Nodules are generated by processing phosphate ore in a rotary kiln. The kiln's exhaust is routed through four parallel hydrosonic scrubbing systems. The coke, quartzite, and nodules are then combined and heated in three electric furnaces. Particulate emissions from the furnaces are controlled by electrostatic precipitators. The cleaned gases are sent through water spray condensers where the gases are cooled, condensing the phosphorus, which is then pumped to settling/storage tanks. The stored phosphorus is loaded into water-sealed railroad cars for shipment. Slag and ferrophosphorus from the furnaces are stockpiled on site.

1.2 Permitting Action and Facility Permitting History

This T2 establishes permit limitations for Best Available Retrofit Technology (BART) compliance in accordance with 40 CFR 51.308(e). See the current Tier I permit statement of basis for the permitting history.

2. APPLICATION SCOPE AND APPLICATION CHRONOLOGY

2.1 Application Scope

This permit is being issued to establish permit conditions that will demonstrate compliance with BART. An analysis is done to identify the sources that are subject to BART and determine what constitutes BART for the applicable sources.

2.2 Application Chronology

This DEQ-initiated permit action uses information submitted by P4 for a revised Tier II operating permit (July 31, 2006) which was replaced and updated by a facility-wide PTC application (June 11, 2009).

August 11, 2009	Permitting project initiated
September 11, 2009	Facility draft permit issued
September 23, 2009	Comments received from facility
October 8, 2009	Public comment period starts
November 9, 2009	Public comment period ends

3. TECHNICAL ANALYSIS

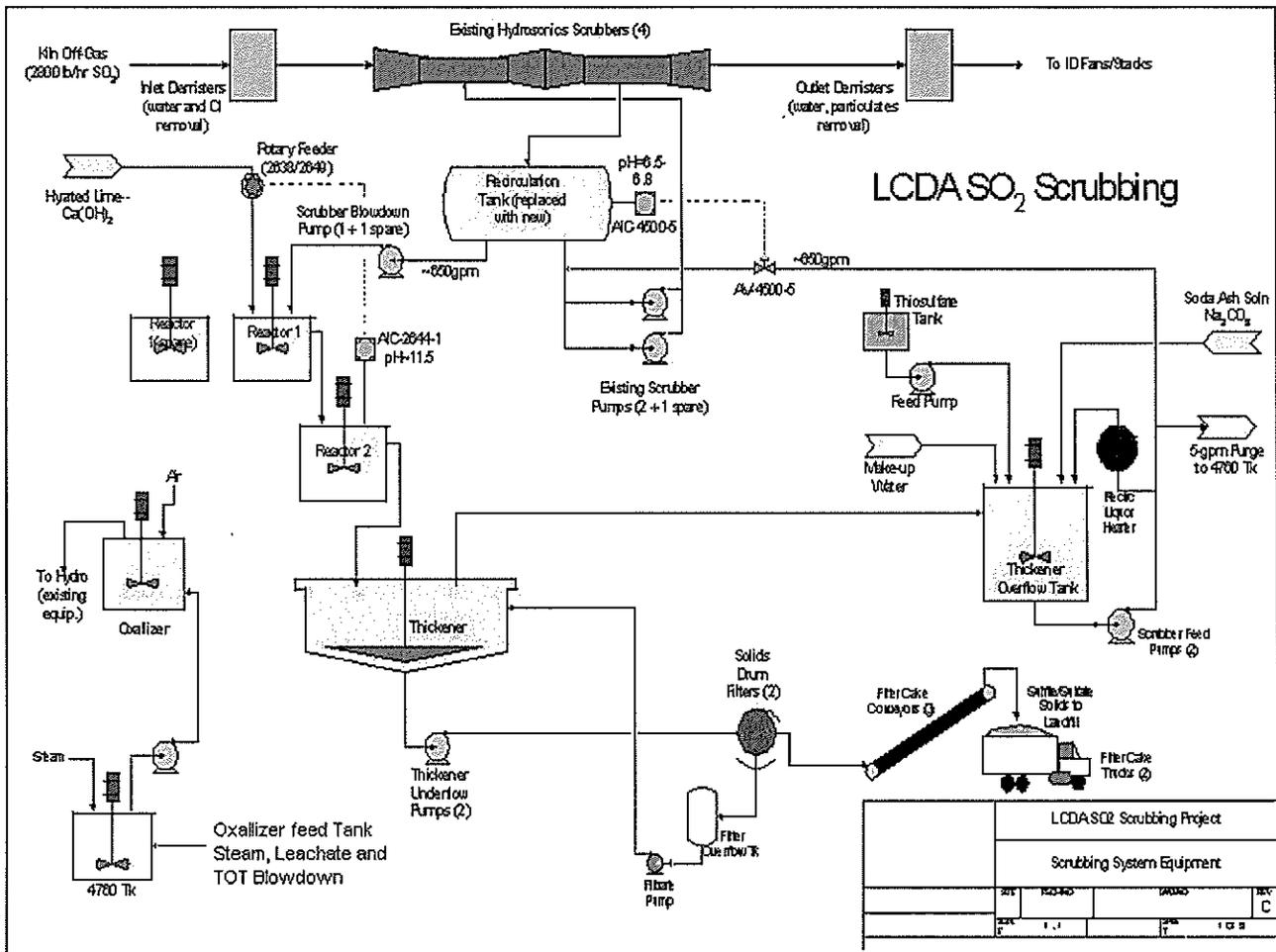
3.1 Emission Unit and Control Device

Table 3.1 EMISSION UNIT AND CONTROL DEVICE INFORMATION

Emissions Unit Description	Control Device Description
Kiln	Dust knockout chamber North spray tower Eight parallel cyclonic separators Four parallel Hydro-Sonic scrubbers and demisters SO ₂ scrubbing system (LCDA)

The purpose of the SO₂ Abatement System is to remove sulfur dioxide (SO₂) from the kiln off-gas stream before it is emitted to the atmosphere. A high pH solution of sodium (from soda ash (sodium carbonate), Na₂CO₃) is used to absorb the sulfur dioxide in the Hydro-Sonic scrubbers. SO₂ is removed in an acid/base reaction between the acid gas, sulfur dioxide, and basic sodium solution. A mixture of sodium sulfite and sodium sulfate is formed in solution. The solution also serves as the collection

medium for the particulate in the Hydrosonic scrubbers. The process is illustrated in the following diagram.



Blow-down from the Recirculation Tank prevents buildup of the sulfur compounds and particulate in the scrubbing liquor. This blow-down is directed to the Lime Concentrated Dual Alkali (LCDA) facility to regenerate the scrubbing liquor. In the LCDA facility, hydrated lime ($\text{Ca}(\text{OH})_2$) is added stoichiometrically to the blow-down in reactor 1 (R1) to remove the sulfur compounds. The lime reacts with the sulfite and sulfate to form a solid precipitate (a mixture of calcium sulfite and calcium sulfate). The resulting slurry is directed into a second, larger, reactor (R2) where the precipitate crystals are allowed to grow over time, making them easier to separate when filtering. The resulting slurry is then directed to a Thickener where the bottom slurry, containing the solids, is separated from the supernatant (overflow). Before the supernatant is returned to the Recirculation Tank, fresh soda ash is added to the Thickener Overflow Tank to make up for losses to the cake and the Hydroclarifier. The Thickener underflow reports to the Vacuum Drum Filters in the Belt Filter Press (BFP) building where the solids and liquid are further separated. The filtered water is returned to the LCDA process. The cake formed on the filter drums is removed and conveyed to haul trucks for delivery to an on-site landfill. Any water that leaches from the impounded cake in the landfill is collected and returned to the Oxallizer Feed Tank. That tank also receives blow-down from the process and routes the combined waters to the Oxallizer, where any sulfite is oxidized to sulfate before reporting to the Hydroclarifier. Under certain rare conditions, sodium thiosulfate ($\text{Na}_2\text{S}_2\text{O}_3$) may be added to the Thickener Overflow Tank to suppress formation of too much sulfate in the final cake.

3.2 Emissions Inventory

Only BART pollutants are addressed in this inventory. Although not considered, emissions of other regulated air pollutants are not expected to increase as a result of this permitting action.

Documentation for the emissions estimations are shown in detail in the June 2009 application for a permit to construct, Pages 230 – 242, and in the emission inventory spreadsheet portion of the application. Some of the documentation is summarized in this section of the statement of basis.

Table 3.2 CONTROLLED EMISSIONS ESTIMATES OF BART POLLUTANTS POTENTIAL TO EMIT

Emissions Unit	PM ₁₀		SO ₂		NO _x	
	lb/hr	T/yr	lb/hr	T/yr	lb/hr	T/yr
Kiln Stacks (4)	30	131.4	143.01	626.39	856.33	3750.72

The facility’s emissions inventory was submitted in electronic form as a series of spreadsheets. The sheet titled “PSD Query Worksheet” estimates emissions after the control equipment has been installed.

KILN

Emission Control Description

P4 Production’s phosphate ore nodulizing kiln has particulate emissions, including polonium-210, and SO₂ emissions. The particulate emissions are controlled by a dust knockout chamber, eight cyclonic separators, and four Hydro-Sonic scrubbers. A spray tower controls emissions from the nodule cooler. The SO₂ emissions are controlled by a lime concentrated dual alkali (LCDA) SO₂ scrubbing system. This system consists of Hydro-Sonic scrubbers that absorb SO₂ with a solution of sodium salts. Some sodium sulfate is produced. The spent solution of sodium sulfite/bisulfite/sulfate is continuously withdrawn to a dual-reactor system, where it is reacted with hydrated lime. The lime regenerates the scrubbing solution and precipitates calcium sulfite/sulfate solids. The solids are removed from the system through thickening and filtration, and the regenerated solution is returned to the scrubber as feed material. The LCDA installation includes raw material storage tanks, two reactor tanks, thickener/clarifier, filtration (feed tank with vacuum filtering process), and a double lined landfill with leachate collection.

A more detailed description and a process diagram of the Kiln SO₂ scrubbing system is included in Appendix B.

PM₁₀ Emissions Estimate

The PM₁₀ hourly emissions rates estimated and modeled for the kiln and cooler spray tower were the result of testing done June 25, 2008 through August 20, 2008. The annual PM₁₀ emissions are the hourly limit times 8,760 hours of operation per year.

NO_x Emissions Estimate

The origin of the NO_x emissions estimate is based on stack testing and is explained in the comment in the application’s spreadsheet, Appendix J – Technical Support Document Final 7-26-06, cell AA16:

“Maximum lb/hr estimated at average conc + 3 sigma based on the 2002 -2003 sampling or 908 ppm (dv) before dilution by hydro vent. Maximum total 4 stack gas volume estimated at 330,000 acfm wet (35,366 #mol wet) and 36.8% H2O vapor. Overall adjustment for hydro vent dilution of #4 train is (3.67/4) i.e., over all average max conc = 908 x 3.67/4 = 833 ppm (dv).”

$908/1000000*(3.67/4)*35366*(1-0.368164)*4 = 856.3 \text{ lb/hr}$. Maximum annual estimates are based on the very conservative maximum hourly times 8760 hr/yr.”

An excerpt from additional information from the facility, dated August 31, 2007:

“Some preliminary NO_x sampling of the kiln exhaust gases in 2000 were judged not reliable enough to predict potentials to emit for the Tier II effort. So in 2002 & 2003 while pilot plant work was proceeding on the SO₂ reduction project, a temporary continuous monitor was installed on a slip stream taken from the number 1 Hydro-Sonics scrubbing train. The operation of this equipment was supervised by an analytical instrument engineer during the test periods. Approximately 200 hours of data was gathered between 10/02 & 3/03 and statistically analyzed. The average NO_x was 465 ppm (dv) and to insure a conservative estimate, the average plus 3 sigma or 908 ppm (dv) was used for estimating the PTE. The four Hydro-Sonics scrubbing trains handle the exhaust gases from the kiln after being first scrubbed in the North Spray Tower plus about 25,000 ACFM of air sweeping the vapor space of the hydroclarifier. The purpose of the sweep air is to insure there is no buildup around the hydroclarifier of PH₃ or H₂S that could pose a personnel hazard. There would be no NO_x or CO in this stream. Due to the physical arrangement of the Hydro-Sonics inlet manifold, the sweep air essentially all goes to the number 4 Hydro-Sonics train diluting the discharge. Since the NO_x & CO sampling was all done on the undiluted number 1 train, the average for the four train emissions was adjusted to reflect this dilution and the total NO_x PTE shown, 856 #/hr, is for all four stacks. For ease of modeling all four stacks which are closely clustered, were modeled at the same emission levels.”

SO₂ Emissions Estimate

The SO₂ emissions from the kiln were calculated by the facility in the application, PSD Query Worksheet, comment for Cell AL3195, using the following equation:

$$100 \text{ ppm SO}_2 \times 35366 \text{ lbmol/hr} * \times (1 - 0.368164**) \times 64 = \underline{143 \text{ lb/hr SO}_2}$$

* 330,000 acfm wet gas, the off-gas rate from the kiln

** 36.8164 % water

64 is the molecular weight of SO₂

According to Carol Adams of P4 in a phone conversation on 7/20/05, the 100 ppm SO₂ was a tested value from a pilot scale study to assess the feasibility of the LCDA process.

The control efficiency of the scrubbers for SO₂ depends on the pH of the scrubbing solution. The solution enters the scrubber at a pH of 11 to 11.5. The solution leaves the scrubber at a pH of about 6.5. If the scrubbing media pH drops below about 6.5, the control efficiency drops quickly. Therefore, a permit condition limiting the pH is required. Source testing has been done that determined the lowest pH required to prevent exceedance of the modeled SO₂ level, for which a limit is being established in this permit. Because the recirculation tank has a large capacity, changes in pH in the scrubber solution will be buffered by the large volume in the tank. Testing shows that the emissions of SO₂ can be correlated to the pH in the recirc tank (Appendix E).

The SO₂ emissions from the cooler spray tower are based on stack testing done in October on 1998 (93 lb/hr) and a linear extrapolation of sulfur content in the ore. The sulfur in the ore during the test was 1.389% SO₃ equivalent. This is one of the higher sulfur ores. The calculations for emissions are based on 2.74% SO₃ equivalent in the ore, so the SO₂ emissions are estimated conservatively high.

Further details about the emission estimations are included in Appendix B.

4. REGULATORY REVIEW

4.1 Attainment Designation (40 CFR 81.313)

The facility is located in Caribou County which is designated as attainment or unclassifiable for PM₁₀, PM_{2.5}, CO, NO₂, SO_x, and Ozone. Reference 40 CFR 81.313.

4.2 Tier II Operating Permit (IDAPA 58.01.01.401)

A Tier II operating permit is being issued in accordance with IDAPA 58.01.01.401.03.b. Specific limits are necessary to ensure compliance with the requirements specified in 40 CFR 51.308(e). NSPS, NESHAP, PSD, Title V applicability and classifications are not expected to change as a result of BART implementation or this permitting action. CAM will be addressed during the next Title V permit renewal in accordance with 40 CFR 64.5(a)(3).

4.3 Best Available Retrofit Technology (BART)(40 CFR 51.308(e))

40 CFR 51.308(e)..... Best Available Retrofit Technology

Appendix E includes an analysis for this subpart's requirements. All BART equipment is currently installed and operating. This permit contains permit conditions to require continued operation, monitoring, and recordkeeping.

A summary of the requirements and the permit conditions are presented as follows:

(e) Best Available Retrofit Technology (BART) requirements for regional haze visibility impairment. The State must submit an implementation plan containing emission limitations representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area, unless the State demonstrates that an emissions trading program or other alternative will achieve greater reasonable progress toward natural visibility conditions.

Two sources at P4 were identified as potential BART-Eligible Sources (as defined at IDAPA 58.01.01.006.14): The phosphate ore nodulizing kiln (#5 Kiln) and the #9 Furnace (#9 THFC and #9 CO Flare). The results of the BART determinations (pursuant to IDAPA 58.01.01.668) for these two emission units are summarized in Table 4.1.

Table 4.1 BART FOR P4 PRODUCTION, L.L.C. BART-ELIGIBLE UNITS

Emission Unit	Regional Haze Pollutant	BART Determination	Emission Limit	Origin of Emission Limit
Nodulizing Kiln (#5 Kiln)	SO ₂	Existing Federally Enforceable Controls: Limit coal sulfur content to a maximum of 1% by weight. BART: Lime Concentrated Dual Alkali (LCDA) SO ₂ scrubbing system	143 lb/hr	Tier II Operating Permit No. T2-2009.0109
	NO _x	Existing Federally Enforceable Controls: None BART: No additional controls.	None	
	PM	Existing Federally Enforceable Controls: Knockout chamber, spray tower, four parallel high energy (HE) venturi scrubbers, and eight parallel cyclonic separators BART: No additional controls.	Process weight rate, the emissions limit is an equation and applies to emissions from the kiln and the cooler combined, estimated and modeled for the kiln at 30 lb/hr	IDAPA 58.01.01.702, Operating Permit No. 13-0420-0001-02, issued July 18, 1979, Tier I Operating Permit No. T1-060316 issued July 14, 2009, Permit Condition 3.2.
#9 Furnace (#9 THFC & #9 CO Flare)	SO ₂	Existing Federally Enforceable Controls: None BART: No additional controls	None	
	NO _x (PTE for THFC less than 40 T/yr, so not BART applicable)	Existing Federally Enforceable Controls: None BART: No additional controls	None	
	PM	Existing Federally Enforceable Controls: #9 THFC: wet venturi scrubber #9 CO Flare: None BART: #9 THFC: No additional controls #9 CO Flare: No additional controls	<u>Furnace THFC</u> ^a : ≤ 352,000 lb/hr: 0.2 lb per ton of material fed to furnace > 352,000 lb/hr: Process Weight <u>Flare</u> : 0.2 lb per 100 lb burned	For THFC, IDAPA 58.01.01.702, Operating Permit No. 13-0420-0001-09, issued July 18, 1979, Tier I Operating Permit No. T1-060316 issued July 14, 2009, Permit Condition 21.1. Also see reference "a" for this table. For flare, IDAPA 58.01.01.786.02, Tier I Operating Permit No. T1-060316 issued July 14, 2009, Permit Condition 24.1.

^a The permittee requested a streamlining of the operating permit particulate matter limit and the process weight limit (IDAPA 58.01.01.702). Streamlining means that only the most stringent limit shall apply. The operating permit limit of 0.2 pounds per ton is the most stringent below a process weight of 352,000 lbs/hour (176 T/hr). Above this process weight the process weight rate equation is more limiting. In a letter dated June 5, 2001, the permittee certified that the process was installed prior to October 1, 1979. Therefore, the applicable standard is IDAPA 58.01.01.702.

(1) To address the requirements for BART, the State must submit an implementation plan containing the following plan elements and include documentation for all required analyses:

(i) A list of all BART-eligible sources within the State.

This has been done in the BART SIP document.

(ii) A determination of BART for each BART-eligible source in the State that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area. All such sources are subject to BART.

BART has been determined as shown in Appendix C.

(A) The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

(Break in Section)

(C) Exception. A State is not required to make a determination of BART for SO₂ or for NO_x if a BART-eligible source has the potential to emit less than 40 tons per year of such pollutant(s), or for PM₁₀ if a BART-eligible source has the potential to emit less than 15 tons per year of such pollutant.

For the THFC, based on source testing, the NO_x PTE is 24.8, which is less than 40 T/yr, so it is exempt from BART requirements. The THFC is subject to BART for PM₁₀ and SO₂. The kiln and the flare are subject to BART for PM₁₀, NO_x, and SO₂.

(iii) If the State determines in establishing BART that technological or economic limitations on the applicability of measurement methodology to a particular source would make the imposition of an emission standard infeasible, it may instead prescribe a design, equipment, work practice, or other operational standard, or combination thereof, to require the application of BART. Such standard, to the degree possible, is to set forth the emission reduction to be achieved by implementation of such design, equipment, work practice or operation, and must provide for compliance by means which achieve equivalent results.

(iv) A requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision.

All BART equipment is currently installed and operating.

(v) A requirement that each source subject to BART maintain the control equipment required by this subpart and establish procedures to ensure such equipment is properly operated and maintained.

The permit requires an operation and maintenance plan to be written for the BART equipment. Also, operating, monitoring, recordkeeping, and emissions testing requirements have been written to ensure that the equipment is being operated to control the emissions to a level no greater than the hourly SO₂ permit limit.

4.4 Permit Conditions Review

This section describes the permit conditions for this permit.

The SO₂ control equipment is described in Permit Condition 2.2.

The SO₂ emissions are limited to 143 lb/hr because that was proposed by the facility in its PTC application, testing has demonstrated that this level is attainable, so this is established in this permit as a technology-based limit.

The pH of the recirculation tank has been measured during source tests that have shown compliance with the emissions limit. It has been determined that a pH as low as 6.1 in the recirculation tank will ensure that the SO₂ is being adequately scrubbed to meet the emissions limit. Therefore, the permit limits the pH to not less than 6.1 on a one-hour average. The permit requires hourly monitoring and recordkeeping of the pH.

The permit contains a requirement that the hydrosonic scrubbers and the LCDA system be operating any time the kiln is operating.

An operation and maintenance manual is required to be written to ensure that the BART equipment is properly operated and maintained.

Routine performance testing is required to assess continued compliance with the SO₂ emissions limit.

5. PUBLIC COMMENT

An opportunity for public comment period on the Tier II operating permit application was provided in accordance with IDAPA 58.01.01.404.02.b. During this time, no comments were submitted in response to DEQ's proposed action. Refer to the chronology for public comment period dates.

Appendix A – AIRS Information

AIRS/AFS Facility-wide Classification Form

Facility Name: P4 Production, LLC
Facility Location: Two miles north of Soda Springs, Idaho, on Highway 34
Facility ID: 029-00001 **Date:** August 12, 2009
Project/Permit No.: T2-2009.0109 **Completed By:** Carole Zundel

Check if there are no changes to the facilitywide classification resulting from this action. (compare to form with last permit)

Yes, this facility is an SM80 source.

Identify the facility's area classification as A (attainment), N (nonattainment), or U (unclassified) for the following pollutants:

	SO2	PM10	VOC	
Area Classification:	U	U	U	DO NOT LEAVE ANY BLANK

Check one of the following:

SIP [0] - Yes, this facility is subject to SIP requirements. (do not use if facility is Title V)

OR
 Title V [V] - Yes, this facility is subject to Title V requirements. (If yes, do not also use SIP listed above.)

For SIP or TV, identify the classification (A, SM, B, C, or ND) for the pollutants listed below. Leave box blank if pollutant is not applicable to facility.

	SO2	NOx	CO	PM10	PT (PM)	VOC	THAP
Classification:	A	A	A	A	A		B

PSD [6] - Yes, this facility has a PSD permit.

If yes, identify the pollutant(s) listed below that apply to PSD. Leave box blank if pollutant does not apply to PSD.

	SO2	NOx	CO	PM10	PT (PM)	VOC	THAP
Classification:	<input type="checkbox"/>						

NSR - NAA [7] - Yes, this facility is subject to NSR nonattainment area (IDAPA 58.01.01.204) requirements.

Note: As of 9/12/08, Idaho has no facility in this category.

If yes, identify the pollutant(s) listed below that apply to NSR-NAA. Leave box blank if pollutant does not apply to NSR - NAA.

	SO2	NOx	CO	PM10	PT (PM)	VOC	THAP
Classification:	<input type="checkbox"/>						

NESHAP [8] - Yes, this facility is subject to NESHAP (Part 61) requirements. (THAP only)

If yes, what CFR Subpart(s) is applicable? K

NSPS [9] - Yes, this facility is subject to NSPS (Part 60) requirements.

If yes, what CFR Subpart(s) is applicable?

If yes, identify the pollutant(s) regulated by the subpart(s) listed above. Leave box blank if pollutant does not apply to the NSPS.

	SO2	NOx	CO	PM10	PT (PM)	VOC	THAP
Classification:	<input type="checkbox"/>						

MACT [M] - Yes, this facility is subject to MACT (Part 63) requirements. (THAP only)

If yes, what CFR Subpart(s) is applicable?

Appendix B – Emissions Inventory

3/24/09 dcd
~~10-14-08 ded~~
~~4-29-08 ded~~
7/26/2006 ela

Attachment 5

Kiln Cooler Spray Tower Emissions Estimate Basis (Source #314)

PM10

All particulate emissions are assumed to be PM10. Current Max permitted limit for 4 kiln stacks + cooler stack limited to 39.02 #/hr by current Tier I permit limit using process wt table and EPA method 5 sampling protocol. Previous Cooler stack max allocation set at 18.6 #/hr based on max 3 run average measured cooler stack set from 1988-2001.

Rev 10/13/08: Per IDEQ, for NAAQS compliance dispersion modeling, estimated max particulates must be based on EC202 sampling protocol for total particulates which also includes condensables. An internal sampling program April thru July 2008 using EC202 was carried out on the kiln cooler tower stack experimenting with different nozzle types & scrubber water pressure. A total of 53 samples were taken using method EC202 with an average total particulates = 16.73 lb/hr. Again there was considerable variability with an average + 2 sigma level = 26.58 lb/hr. The average of the maximum 3 samples = 22.7 lb/hr with the recommended type nozzles. Some improvements in demister performance are anticipated. Therefore it is estimated that a max level of 27 lb/hr for short term dispersion modeling and Tier II permitting is reasonable. An annual estimate would be the short term maximum times 8760 hr/yr. The stack discharge velocity for modeling will be adjusted to match the average 191,590 ACFM flow rate of these 56 test runs.

Rev 3/24/09: In January 2009 it was learned that the 2008 sampling methods used for the cyclonic discharge of the cooler spray tower stack overstated both the gas flow rates and particulate emission rate by about 17%. The corrected average discharge gas flow rate is 160,000 ACFM. This corrected average flow rate is being used in the revised dispersion modeling of all species. To be conservative in the PM-10 estimate and modeling, no credit has been taken for the overstated PM-10 emission rates or for any other species. I.e., a maximum PM-10 rate of 27 lb/hr remains as the PTE estimate and in the modeling.

The new modified facilities to improve entrainment also were included in the modeling with a new fan, entrainment separator and a 7 ft diam x 120 ft tall stack with an average flow rate of 160,000 ACFM and the same emission rates as previously estimated. These facilities are expected to reduce entrainment, i.e., method 5 particulates and provide better dispersion characteristics.

SO₂

Maximum SO₂ emissions are based on compliance stack testing conducted on 10/29/98. The emissions are then adjusted for potential Enoch Valley Mine-like ore at the 95% confidence limit for long-term variation, and also adjusted for a future estimated kiln feed rate corresponding to 164MW of future furnace power load. This also assumes that the emissions are associated with sulfur in the ore, and all ore has a similar volatility.

Stack testing for SO₂ in the kiln area was conducted from 10/28/1998 through 10/31/1998. The average of the three stack sampling runs was 93 lb/hr. It is reasonable to assume that the cooler spray tower stack emissions are linked to the kiln feed rate and to the concentration of sulfur (expressed as %SO₃) in the kiln feed or mined ore.

The average kiln feed rate during the four (4) day testing period was 205.5 DNT/hr which would be equivalent to 1,800,180 DNT/yr if annualized, assuming the same hours of operation for the entire year. Therefore, the emissions factor that resulted from the testing was $93/205.5 = 0.45$ lb SO₂/ton of kiln feed. During the testing period, the average sulfur in the Enoch ore portion of the kiln feed was 1.389% SO₃ equivalent. Since this is one of the higher sulfur ores that is fed to the kiln, it was used for the emissions estimate basis. A statistical analysis of the long-term (year to year) Enoch ore sulfur variability indicates a maximum sulfur content of 2.30% SO₃ at the 95% confidence level. Plant tests over 11.5 months in 1998-99 indicate that the combination of short-term and long-term variability could result in a maximum short-term (day to day) sulfur content of 2.74% SO₃.

To estimate emissions for future operating conditions, it is necessary to adjust the measured emissions rate to a period of time when both the actual kiln feed rates using Enoch ore, and the corresponding total furnace power consumed are known. The two-year period that was selected to be used for the annual average future operating conditions was 2001 and 2002.

The average annual kiln feed rate is 1,611,568 DNT/yr.

The average annual total furnace power consumed is 1,257,418,046 KW/yr.

Future operating conditions: Furnace power load = 164 MW/yr

Operating hours = 8,284 hrs/yr (94.57%)

Annual Maximum Emissions

SO₂ Estimated Emissions = (measured SO₂/ton) x (S adjust) x (base yr kiln feed) x
(future furnace load / base yr furnace load)/2000

SO₂ Estimated Emissions = $(93/205.5) \times (2.74/1.389) \times (1,611,568) \times (164,000 \times 8760 \times 0.9457/1,257,418,046) / 2000 = 777.2$ tpy

Hourly Maximum Emission Rate

SO₂ Emissions Rate = (annual maximum emissions) / (maximum operating hours %)
(deleted typo referring to short term S adjustment as it was already included in annual estimate calculation)

$$\text{SO}_2 \text{ Emissions Rate} = (777.2 \times 2000) / (8760 \times 1.0) = 177.5 \text{ lb/hr}$$

The SO₂ emissions estimates are considered reasonable considering the limited amount of SO₂ field sampling data available. More accurate estimates would require a major and lengthy field stack sampling program while operating with a variety of kiln ore feedstocks.

The potential for cooler spray tower SO₂ emissions can be monitored by keeping track of the total sulfur (lbs/hr of S) in the ore being fed to the kiln. The estimated 177 lb/hr SO₂ emission rate corresponds to 3892 lb/hr of sulfur in the ore fed to the kiln. I.e., about 2.3% of the sulfur in the ore reports to the cooler spray tower stack as SO₂ emissions.

Appendix C – BART Analysis

Best Available Retrofit Technology (BART) Analysis

for

P4 Production, L.L.C.

Soda Springs, Idaho

Facility ID No. 029-00001



Photo Credit: Peter Clegg (posted on Google Earth)



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Acronyms, Units, and Chemical Nomenclatures

acfm	actual cubic feet per minute
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Btu	British thermal unit
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
DSD	duct spray drying
ENE	east-northeast
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
FGD	flue gas desulfurization
FSI	furnace sorbent injection
HE	high energy
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
km	kilometer
LAER	Lowest Achievable Control Technology
lb/hr	pound per hour
LCDA	Lime Concentrated Dual Alkali
LSD	Lime Spray Drying
LSFO	Limestone Forced Oxidation
m	meter(s)
mi	mile(s)
MACT	Maximum Achievable Control Technology
MEL	magnesium-enhanced lime
MMBtu	million British thermal units
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NH ₄ OH	ammonium hydroxide
NNE	north-northeast
NNW	north-northwest
NO _x	nitrogen oxides
NSPS	New Source Performance Standards
P4	P4 Production, L.L.C.
PM	particulate matter
PM ₁₀	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
PM _{2.5}	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PSD	Prevention of Significant Deterioration
PTE	potential to emit
RACT	Reasonably Available Control Technology
RBLC	(EPA's) RACT/BACT/LAER Clearinghouse
Rules	Rules for the Control of Air Pollution in Idaho
scf	standard cubic feet
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	Selective non-catalytic reduction
SO ₂	sulfur dioxide
THFC	tap hole fume collector
T/yr	tons per year
VOC	volatile organic compound

1. Executive Summary

The P4 Production, L.L.C. (P4) facility located in Soda Springs, Idaho, produces elemental phosphorus. Coke, quartzite, phosphate ore, and clinker are delivered to the site by truck or railcar. The coke and quartzite are dried, if needed, and screened. Phosphate ore is fed to a rotary kiln (calciner) to form heat-hardened nodules. The exhaust from the kilns is controlled by a dust knockout chamber, nodulizing kiln spray tower, eight parallel cyclonic separators, and four parallel hydrosonic scrubbing systems. The hydrosonic scrubbing system includes an SO₂ scrubbing system.

Nodules are then combined with coke and quartzite and heated in a reducing environment in one of three electric furnaces. The furnace vent gases, which contain the phosphorus product in a vapor state, pass through two electrostatic precipitators to remove entrained particles. The vent gas is then sent to water spray condensers where the gases are cooled, and the product phosphorus is condensed. The vent gas is then sent to the nodulizing kiln or a furnace flare to oxidize carbon monoxide (CO) to carbon dioxide. The condensed phosphorus is pumped to settling/storage tanks and then loaded into water-sealed railroad cars for shipment. Slag and ferrophosphorus are regularly removed from the furnaces (a procedure referred to as “tapping”) and stockpiled on site. Emissions associated with tapping the furnaces are collected and controlled by the Tap Hole Fume Collector Scrubber (THFC).

Two sources at P4 were identified as potential BART-Eligible Sources (as defined at IDAPA 58.01.01.006.14), the phosphate ore nodulizing kiln (#5 Kiln) and the #9 Furnace (#9 THFC and #9 CO Flare). The Idaho Department of Environmental Quality (DEQ) has completed a determination to identify all BART-Eligible Sources at the P4 facility. The results of the BART determinations (pursuant to IDAPA 58.01.01.668) for these two emission units are summarized in Table 1.1.

P4 is under a consent order to meet BACT for CO emissions from the #7 furnace and to install the same controls on the #8 and #9 furnaces. P4 has proposed that either a thermal oxidizer and high energy (HE) venturi scrubber or controlling operations to balance the CO produced in the furnaces to match the fuel needs for the kiln constitute BACT for CO (the CO BACT Measures). P4 has applied for a permit to construct that will include federally-enforceable requirements for the SO₂ scrubber system and for the CO BACT measures.

Table 1.1. BART FOR P4 PRODUCTION, L.L.C. BART-ELIGIBLE UNITS

Emission Unit	Regional Haze Pollutant	BART Determination	BART Emission Limit	Nearest Mandatory Class I Area(s)
Nodulizing Kiln (#5 Kiln)	SO ₂	Existing Federally Enforceable Controls: Limit coal sulfur content to a maximum of 1% by weight. BART: Lime Concentrated Dual Alkali (LCDA) SO ₂ scrubbing system	143 lb/hr	Grand Teton National Park ~113 km (~70.2 mi) to the north-northeast (NNE) Bridger Wilderness ~ 143 km (~88.8 mi) to the east-northeast (ENE) Teton Wilderness ~164 km (~102 mi) to the NNE Fitzpatrick Wilderness ~ 164 km (~102 mi) to the ENE
	NO _x	Existing Federally Enforceable Controls: None BART: No additional controls.	n/a	
	PM	Existing Federally Enforceable Controls: Knockout chamber, spray tower, four parallel high energy (HE) venturi scrubbers, and eight parallel cyclonic separators BART: No additional controls.	n/a	
#9 Furnace (#9 THFC & #9 CO Flare)	SO ₂	Existing Federally Enforceable Controls: #9 THFC: None #9 CO Flare: None BART: #9 THFC: No additional controls #9 CO Flare: No additional controls	n/a	Yellowstone National Park ~166 km (~103 mi) to the NNE Washakie Wilderness 184 km (~115 mi) to the NNE Craters of the Moon National Monument ~165 km (~103 mi) to the north-northwest (NNW)
	NO _x	Existing Federally Enforceable Controls: None BART: #9 THFC: No additional controls #9 CO Flare: No additional controls	n/a	
	PM	Existing Federally Enforceable Controls: #9 THFC: wet venturi scrubber #9 CO Flare: None BART: #9 THFC: No additional controls #9 CO Flare: No additional controls	<u>Furnace THFC:</u> ≤ 352,000 lb/hr: 0.2 lb per ton of material fed to furnace > 352,000 lb/hr: Process Weight <u>Flare:</u> 0.2 lb per 100 lb burned	

2. Introduction

2.1 Source Description and Background

The P4 facility located in Soda Springs, Idaho, produces elemental phosphorus. Coke, quartzite, phosphate ore, and clinker are delivered to the site by truck or railcar. The coke and quartzite are dried, if needed, and screened. Phosphate ore is fed to a rotary kiln (calciner) to form heat-hardened nodules. The exhaust from the kilns is controlled by a dust knockout chamber, nodulizing kiln spray tower, and four parallel hydrosonic scrubbing systems.

Nodules are then combined with coke and quartzite and heated in a reducing environment in one of three electric furnaces. The furnace vent gases, which contain the phosphorus product in a vapor state, pass through two electrostatic precipitators to remove entrained particles. The vent gas is then sent to water spray condensers where the gases are cooled, and the product phosphorus is condensed. The vent gas is then sent to the nodulizing kiln or a furnace flare to oxidize carbon monoxide (CO) to carbon dioxide. The condensed phosphorus is pumped to settling/storage tanks and then loaded into water-sealed railroad cars for shipment. Slag and ferrophosphorus are regularly removed from the furnaces (a procedure referred to as “tapping”) and stockpiled on site. Emissions associated with tapping the furnaces are collected and controlled by the Tap Hole Fume Collector Scrubber (THFC).

Criteria for determining whether an emission unit is subject to Best Available Retrofit Technology (BART) are described in the next section.

2.2 BART-Eligible Sources

A BART-Eligible Source is “any [of 26 listed categories of] stationary sources of air pollutants, including any reconstructed source, which was not “in operation” prior to August 7, 1962, and was in existence on August 7, 1977, and has a potential to emit two hundred fifty (250) tons per year or more of any air pollutant [including fugitive emissions, to the extent quantifiable].” IDAPA 58.01.01.006.14. Among the identified categories of stationary sources are “phosphate rock processing plants.” IDAPA 58.01.01.006.14.m.

When the P4 elemental phosphorus plant began operation in 1952, the emission units consisted of the #4 Kiln, #7 Furnace, #8 Furnace, #7/8 CO Flare, and ancillary equipment/processes and buildings, including nodule screening and crushing operations. The #5 Kiln replaced the #4 Kiln in 1965 and the #9 Furnace (including the #9 CO Flare) was added in 1966. Two pollution control devices, a nodule cooler spray tower and nodule crushing and screening scrubber, were added in 1970. In 1989, the #7 furnace transformer was replaced to increase the power output and therefore increase the production capacity of that furnace by about 12 percent. The #7 furnace hearth was replaced in 1994 by rebuilding the furnace hearth at a lower elevation and modifying the riser duct, which increased the #7 furnace production by about 16 percent. To control kiln emissions, four (4) high-energy tandem nozzle venturi scrubbers were brought on-line in September of 1987, and an SO₂ scrubbing system was installed in 2005. P4 has submitted an application for a Tier II operating permit, which was revised and re-submitted as a permit to construct application on June 11, 2009.

Potential to Emit (PTE) is defined as “the maximum capacity of a facility or stationary source to emit an air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the facility or source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, **shall be treated as part of its design if the limitation or the effect it would have on emissions is state or federally enforceable.**” IDAPA 58.01.01.006.81 (emphasis added).

The PTE for P4 emission units is summarized in Table 2.1 for the BART-eligible emission units based on limitations contained in the federally-enforceable Tier I operating permit and expected federally-enforceable limitations to be incorporated in a Tier II operating permit or a permit to construct.

Table 2.1 P4 EMISSION UNIT PTE

Emission Unit	Year Installed	Idaho SIP Regional Haze Pollutant	“Current” PTE	2004 CEER Actual Emissions	Notes
			(T/yr)	(T/yr) ^a	
Nodulizing Kiln (#5 Kiln)	1965	SO ₂	626.4 ^b	12,252	Actual emissions are from combustion and phosphate ore-related emissions.
		NO _x	3,750.7 ^b	1,625	
		PM	89.4 ^b	38	
#9 Furnace (including the #9 CO Flare)	1966	SO ₂	#9 Furnace: 117.8 ^a #9 CO Flare: 6.0 ^b	0.12	CEER Actuals are #9 CO Flare emissions only.
		NO _x	#9 Furnace: 65.7 ^a #9 CO Flare: 6.7 ^b	0.13	
		PM	#9 Furnace: 163.6 ^a #9 CO Flare: 31.7 ^b	0.65	
Total PTE from BART-eligible units		SO ₂	1,124		Total PTE exceeds 250 T/yr
		NO _x	3,823		Total PTE exceeds 250 T/yr
		PM	285		Total PTE exceeds 250 T/yr

^a Letter, P4 to Michael Edwards, September 6, 2006.

^b Based on expected federally-enforceable limits to be included in a requested permit to construct

DEQ has concluded that:

1. The P4 facility is a “phosphate rock processing plant;”
2. The #5 Nodulizing Kiln and the #9 Furnace are the only emission units at P4 that began operation after August 7, 1962 and were in existence on August 7, 1977; and
3. PTE for both the #5 Nodulizing Kiln and the #9 Furnace exceed 250 tons per year of any air pollutant.

Based on the conclusions above, DEQ has determined that the #5 Kiln and the #9 Furnace (including the #9 CO Flare) emission units at P4 are BART-eligible sources.

2.3 BART Analysis Methodology

Best Available Retrofit Technology (BART) is defined as “an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by [a BART-eligible source]. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, **any pollution control equipment in use or in existence at the source**, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.” IDAPA 58.01.01.006.16.

P4 submitted a BACT analysis for SO₂ emissions from the #5 Kiln,¹ and a CO BACT analysis for the #7 Furnace and #7/#8 CO Flare. P4 has proposed that either a thermal oxidizer and scrubber or operational controls to balance CO production from the furnaces to match the fuel consumption requirements in the kiln constitutes BACT for CO. Pursuant to the requirements of a consent order, P4 will apply the same technology to the #9 furnace and #9 CO flare. This information was used by DEQ as the starting point for evaluating BART for BART-eligible sources.

This analysis addresses the following five basic steps for a case-by-case BART analysis:

Step 1. Identify all available retrofit control technologies. This must include identification of the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies. This list is considered complete if it includes the maximum level of control each technology is capable of achieving.

To begin Step 1 of the BART analysis, the U.S. Environmental Protection Agency’s (EPA) Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Control Technology (LAER) Clearinghouse (RBLC) database was queried for recent BACT determinations for large industrial sources. The search parameters were for all permits (draft or final) issued since 2001 that included SO₂, NO_x, or PM as a controlled pollutant.

Step 2. Eliminate technically infeasible options.

The decision regarding whether a particular technology was “technically feasible” was based on discussions found in Section IV.D.2 (STEP 2 of EPA’s Guidelines for BART Determinations Under the Regional Haze Rule, 40 C.F.R. Part 51, Appendix Y. Control technologies are technically feasible if either:

- (1) They have been installed and operated successfully for the type of source under review under similar conditions, or
- (2) The technology could be applied to the source under review.

Judgment was used to narrow the list of options if some options were clearly inferior (e.g., controls that are more costly but don’t achieve the reductions of other controls).

Step 3. Evaluate control effectiveness of the remaining control technologies.

Step 4. Evaluate impacts of each remaining control technology, including:

- An estimate of the cost of compliance,
- An evaluation of the energy impacts of each BART option,
- An evaluation of the non-air quality impacts of each BART option, and
- The remaining useful life of the source.

¹ Revised permit to construct application, submitted, 2009. Appendix H, SO₂ BACT for Kiln.
P4 BART Analysis Page 8

Step 5. *Evaluate visibility impacts.* Visibility impacts were not evaluated for each technology. See Section 4 for a discussion of the visibility impacts. Step 5 for this BART analysis is to *Select BART.*

3. BART-Eligible Emission Units Subject to a MACT Standard

None of the potentially BART-subject emission units at P4 are subject to a MACT standard.

4. Baseline Conditions and Visibility Impacts for BART-Eligible Emission Units

Facility-specific visibility impacts for the potentially BART-eligible emission units at P4 have not been modeled. In addition, DEQ determined that CALPUFF modeling for these emission units was not necessary based on the conclusion that P4 is currently implementing control technologies that meet BART for the #5 Kiln and the #9 Furnace and #9 CO Flare. Federally-enforceable permit conditions will be put in place that require P4 to use these BART technologies. DEQ will conduct visibility impact analyses based on emissions within an airshed.

5. BART Analysis for the Nodulizing Kiln (#5 Kiln)

The Nodulizing Kiln (#5 Kiln) is used to produce phosphate nodules for processing in the facility's furnaces. Phosphate ore, dried underflow solids from the current scrubber tower clarifier, and ore dust from the kiln's drop out chamber are heated to high temperatures (1,500°C) to remove organic material and to thermally agglomerate the mixture to a nodular form. The 325-foot long rotary kiln is primarily fueled by carbon monoxide (CO), a by-product of the plant's three electric arc furnaces. Coal and natural gas are used as supplemental fuel sources. The overall gas flow rate exiting the kiln is approximately 263,800 actual cubic feet per minute (acfm).

Existing federally-enforceable process and air pollution controls for the kiln that are addressed in the facility's current Tier I (Title V) operating permit No. T1-060316, consist of:

- A limit on the sulfur content of the coal to no more than 1% by weight.
- A dust knockout chamber, spray tower, demisters, four parallel Hydro-Sonic[®] scrubbers, and eight parallel cyclonic separators. The hydrosonic scrubbers were brought on-line in September 1987 in response to a January 1986 Consent Order. These tandem nozzle fixed-throat free-jet scrubbers are required for control of PM/PM₁₀ and polonium-210 emissions (a radionuclide) found in the phosphate ore.

The initial control device is a settling chamber where large particles are removed. The exhaust flow is then routed to a concrete tower where it passes through water sprays to remove soluble gases and particulate matter. The exhaust flow is then routed to the four parallel Hydro-Sonic[®] scrubbers for removal of submicron particles and entrained particle-laden water. The exhaust gases exit the scrubbers and pass through cyclonic separators and fans prior to exiting to the atmosphere through four stacks.

A lime concentrated dual alkali (LCDA) scrubber to control SO₂ emissions from the kiln was installed by P4 in 2005 in accordance with the requirements of a December 30, 2002 consent order issued by DEQ.

The LCDA scrubbing process uses the existing hydrosonic scrubbers to absorb SO₂ with a solution of sodium salts comprised of sodium sulfite and bisulfite, the active absorbent species. Some sodium sulfate will also be produced. The spent solution of sodium sulfite/bisulfite/sulfate is continuously withdrawn to a dual-reactor system, where it is treated with hydrated lime. The lime regenerates the scrubbing solution and precipitates calcium sulfite/sulfate solids. The solids are removed from the system through thickening and filtration, and the regenerated solution is returned to the scrubber as feed material. In addition to the hydrosonic scrubbers, the LCDA scrubbing system includes raw material storage tanks, two reactor tanks, thickener/clarifier, filtration (feed tank with vacuum filtering process), and a double-lined landfill with leachate collection.

5.1 Kiln SO₂ BART Analysis

SO₂ is formed in the kiln almost exclusively by the oxidation of sulfur present in the process material feed. Small amounts of SO₂ are formed during the limited use of coal and natural gas as kiln fuel.

5.1.1 Identify Control Technologies

In support of a BACT analysis submitted in 2006, P4 searched the RBLC for all permits (draft or final) issued since 2001 that included SO₂ as a controlled pollutant. This search yielded 376 facilities. Processes that were inherently different than the nodulizing kiln at the P4 facility were eliminated from this initial list. For example, all cement kilns were eliminated because the calcium-containing materials processed in these kilns provide for inherent SO₂ removal not found in the feed to the P4 kiln.

The remaining facilities found in the search of the RBLC database included the following process codes:

- 11.110 – External combustion-Solid fuels and solid fuels mixtures –Coal (includes bituminous, subbituminous, anthracite, and lignite),
- 11.130 – External combustion-Solid fuels and solid fuels mixtures-Other solid fuels and solid fuel mixtures,
- 11.900 – External combustion-Other fuels and combinations (e.g. solid/liquid, liquid/gas) wood, gas & oil fired,
- 62.010 – Inorganic chemicals manufacturing,
- 81.002 – Metallurgical Industry, and
- 90.000 – Mineral products.

None of the facilities found employing SO₂ control technologies were under RBLC plant process code 90.013 for elemental phosphorus plants. The BACT emission limits, therefore, are not directly applicable to the P4 nodulizing kiln due to the uniqueness of this process. The control technologies, though, are applicable and have been included in this evaluation.

As part of developing this BART analysis, DEQ reviewed RBLC technologies listed as of July 2008 for these process codes, and confirmed that the 2006 search results are still representative of BACT for these sources. Control technologies that are available to control SO₂ from the #5 Kiln, in top-down order, include:

Wet Flue Gas Desulfurization (FGD)

- Lime or limestone based wet flue gas desulfurization (FGD): ~75 to 98 percent control²

Dry FGD

- Lime Spray Drying (LSD) or lime spray dryer absorber: ~82 to 95 percent control³
- Humidified In-Duct Injection:
 - ~50 to 70 percent control (when followed by a baghouse)³
 - ~35 to 50 percent control (when followed by an ESP)⁴
- Convective Pass Injection: ~50 to 70 percent control⁴
- Furnace Sorbent Injection (FSI):
 - Hydrated lime: ~50 to 65 percent control⁴
 - Limestone ~40 to 50 percent control⁴
- In-Duct Spray Drying (DSD): ~50 to 60 percent control (when followed by an ESP)⁴

Regenerative FGD Processes

- Wet: sodium sulfite, magnesium oxide, sodium carbonate, and amine: up to 97% control³
- Dry: activated carbon.

Process Controls

- Reducing the fuel sulfur content,
- Reducing the sulfur content of other feed material.

The following discussion of available SO₂ controls was compiled by P4 from the RBLC search; searches of the major California Air Pollution Control Agencies web sites (California Air Resources Board, South Coast Air Pollution Control Agency, San Diego County Air Pollution Control Agency, and the Bay Area Air Quality Management District); EPA Regions 4 and 5 websites; EPA Headquarters website; and a review of SO₂ control literature.

Process Controls

Process controls can reduce emissions in a variety of ways, depending on the source. If the emission unit is primarily a combustion source, reducing the sulfur content of the fuel can reduce SO₂ formation. Examples of this type of process control include use of low sulfur distillate oil, natural gas, or coal, if available. If the source is a process unit that includes the addition of feed material, reducing the sulfur content of the feed can control SO₂.

Add-On Controls

There are two major types of add-on controls for SO₂ removal: once-through and regenerable. In once-through technologies, the SO₂ is permanently bound to the sorbent that must be disposed of a waste or utilized as a by-product (i.e., gypsum). In regenerable technologies, SO₂ can be released from the sorbent during its regeneration and the SO₂ may be further processed to yield H₂SO₄, elemental sulfur, or liquid

² EPA, *Controlling SO₂ Emissions: A Review of Technologies*. U.S. Environmental Protection Agency, Office of Research and Development. EPA/600/R-00/093. November 2000.

³ Barbara Toole-O'Neil, editor, chair, *Dry Scrubbing Technologies for Flue Gas Desulfurization*, Consortium Review Committee, Ohio Coal Research Consortium, Publisher: Springer, 1998.

SO₂.⁴ The initial capital costs and annual operation and maintenance (O&M) costs for regenerable technologies are generally higher than for once-through technologies. Regenerable technologies are usually only economically feasible if a reliable buyer can be found for the by-product.³

The most common type of once-through controls, wet scrubbing and dry scrubbing, are collectively known as flue gas desulfurization [FGD] processes. The terms “wet” and “dry” refer to the relative moisture state of the by-product from the process and not necessarily the state of the sorbent in the process.

Wet FGD Processes

In wet scrubbing systems, the flue gas is passed through a slurry consisting of a sorbent in an aqueous medium where the flue gas is cooled to the adiabatic saturation temperature. Particulate and gaseous oxides of sulfur are removed by absorption or chemical reaction. The by-product slurry from this process is dewatered for disposal or sold commercially.

Wet scrubbing systems generally use lime, limestone, or magnesium oxide as sorbents. Limestone is the most common sorbent used in wet scrubbers. In this system, SO₂ reacts with calcium carbonate to form calcium sulfite and carbon dioxide. In the most common version of limestone wet scrubbing, air is injected into the scrubber reactor to oxidize the calcium sulfite to gypsum (hydrous calcium sulfate). Depending on local market conditions, the gypsum can be sold as a product or disposed of as a stable material. This process known as Limestone Forced Oxidation (LSFO) has become the preferred wet FGD process for coal-fired electrical power plants. One reason for the popularity of LSFO is that it minimizes gypsum scaling problems in the absorber.

Additives can reduce the liquid-to-gas ratio and improve sorbent utilization to enhance the efficiency of SO₂ removal in LFSO systems. Organic acids, such as dibasic acid, are commonly added to LFSO systems to improve their SO₂ removal efficiency.

Another variant of limestone scrubbing is Limestone Inhibited Oxidation (LISO). In this process, emulsified sodium thiosulfate is added to the limestone slurry feed to prevent the oxidation of CaSO₃ to gypsum in the absorber by lowering the slurry oxidation level. Other widely used wet FGD technologies are lime, magnesium-enhanced lime (MEL), and dual alkali processes. In the lime process, Ca(OH)₂ slurry is sprayed counter-current to the flue gas flow. The lime slurry is more reactive than the limestone slurry resulting in a smaller absorber compared to a limestone based system. The lime sorbent, however, is generally more expensive than the limestone sorbent.

The MEL process is a variation of the lime process. The lime sorbent in this process contains magnesium. This addition makes the slurry more alkaline removing more SO₂ compared to a similar conventional lime process. The dual (or double) alkali process uses a sodium solution for scrubbing followed by lime treatment of the scrubbing solution. A sodium sulfite solution is sprayed into an open spray tower or another scrubbing arrangement to remove SO₂ from the flue gas. Lime is added to the product solution in an external tank to recover the sodium solution and form a calcium sulfite-rich sludge. This sludge can be oxidized with air to convert it to gypsum, if desired. This process uses lower-liquid/gas ratios than most other wet FGD processes. The process calcium sulfite/sulfate sludge (if not oxidized) is disposed in a lined landfill.

4 Srivastava, R.K and W. Jozewicz, *Flue Gas Desulfurization: State of the Art*. Journal of the Air and Waste Management Association, Volume 51, p. 1676-1688. December 2001.

Another variant of wet scrubbing process is the use of ammonia to combine with SO₂ to form various ammonia salts (ammonia sulfate and ammonium bisulfate). These salts can be sold as a marketable byproduct for use in fertilizers.

In summary, available wet scrubbing technologies for SO₂ removal are:

- Lime-Concentrated Dual Alkali,
- Limestone Forced Oxidation,
- Limestone Inhibited Oxidation,
- Lime,
- Magnesium-enhanced Lime, and
- Ammonia.

Dry FGD Processes

The simplest form of dry scrubbing does not include any added sorbent. In coal-fired combustion devices, naturally occurring alkaline materials found in the coal ash absorb the SO₂ in the flue gas. This process occurs on a filter fabric, the main purpose of which is to capture particulate matter. The alkaline portion of the captured particles will absorb SO₂ until this portion is neutralized or until the particles are removed from the filter bed during a cleaning cycle. The removal efficiency of this type of SO₂ removal varies widely but is relatively low compared to wet FGD processes and is estimated to be approximately 25 to 40 percent.

In dry scrubbers with added sorbent, a chemical slurry is atomized and injected into the flue gas stream (close to saturation) where droplets react with the SO₂ as they evaporate. The resulting dry by-product is collected in the bottom of the dryer or in the particulate removal equipment (such as an electrostatic precipitator [ESP] or a baghouse). The most widely used type of dry FGD process is Lime Spray Drying (LSD). In this process, lime slurry is mixed with the hot flue gas in a spray tower. Simultaneous heat and mass transfer between the alkali in the finely dispersed lime slurry and the SO₂ in the gaseous phase result in a series of reactions a drying of the reacted products. The resulting by-products include calcium sulfate, calcium sulfite, fly ash, and unreacted lime. A portion of this by-product maybe recycled into the spray tower to enhance SO₂ removal. The by-product can usually be disposed of in a non-hazardous waste landfill.³

Other forms of dry FGD processes inject the sorbent as a dry powder into the flue gas at a variety of locations in the processes. The resulting by-product is captured down stream in particulate removal equipment. These types of dry FGD processes include Furnace Sorbent Injection (FSI) and Duct Spray Drying (DSD). Both of these processes have been used in coal-fired boilers.

In FSI, dry sorbent is injected directly into the section of the combustion device where temperatures are between 950 and 1,000°C (1742 °F – 1832 °F). Sorbent particles (most often lime and sometime limestone) decompose and become porous solids with high surface areas. The end product consisting of calcium sulfate and unreacted sorbent leave the combustion device and are captured as a solid in a particulate collection device. In a variant of FSI, after the reaction has occurred in the combustion device, water is sprayed on the flue gas to improve SO₂ removal efficiency and improve sorbent utilization.

In the DSD process, slaked lime slurry is sprayed directly into the ductwork upstream of an ESP. The SO₂ in the flue gas reacts with the alkaline slurry droplets as they dry to form calcium sulfate and calcium sulfite. A residence time of at 1-second and preferably 2-second is required for maximum SO₂ removal.

The water entering with the lime sorbent humidifies the flue gas for better SO₂ removal. The particles are then captured in the ESP. The by-products normally can be disposed of in a lined landfill.³

In summary, available top-down dry scrubbing technologies for SO₂ removal are:

- Lime Spray Drying (LSD, added sorbent),
- Furnace Sorbent Injection (FSI) or dry sorbent injection, and
- Duct Spray Drying.

Regenerative Processes

Amine processes are the most mature regenerative sulfur removal technology, especially in petroleum refining. This process involves absorption of SO₂ within an aqueous amine absorbent. The amine is regenerated thermally to release the SO₂ stream. SO₂ may then be treated by conventional technologies to produce sulfuric acid as a by-product.

5.1.2 Eliminate Technically Infeasible Options

Process Controls

The 2002 Tier I operating permit limits the maximum sulfur content of the coal. Western coals may run as high as 5 to 6% sulfur by weight. Limiting the maximum sulfur content of the coal to 1% by weight is technically feasible.

Pipeline quality natural gas is inherently a very low sulfur fuel. Further reductions in the natural gas sulfur content were not considered.

The phosphate ore contains sulfur, but removal of sulfur from the ore prior to placing it in the kiln is technically infeasible.

Wet FGD Processes

In determining which SO₂ control technology to install in response to a 2002 Consent Order, P4 conducted extensive research and development on the technical feasibility of a variety of SO₂ control technologies in order to meet the unique requirements of the kiln. P4 initially screened hundreds of control technologies, eliminating most as infeasible for the requirements of the kiln. A wide array of requirements and considerations were used to screen these technologies and select a handful that would prove feasible and successful for the P4 kiln. These requirements included: SO₂ emissions, particulate emissions, solid waste properties, process availability/reliability, reuse of existing equipment, raw material supply/quality/cost, integration with existing operations, demonstrated use of technology in similar applications, and flexibility over a wide range of operating conditions. Recycle processes were examined carefully versus once-through processes due to the potential for the buildup of naturally-occurring radioactive materials. Some of the wet scrubbing options were determined infeasible due to potential sodium or calcium salt buildup (scaling) on the current emission control system and for interfering with the cadmium capture (sulfiding) system.

This screening process resulted in the following options:

- Three options involving alkali scrubbing - LSFO and a variant of Dual Alkali scrubbing (Lime Concentrated Dual Alkali scrubbing [LCDA]).

- A system that would scrub the venturi off-gas with ammonium hydroxide (NH₄OH) solution to form a potentially salable by-product (ammonium bisulfite/sulfite solution).
- Two similar systems involving regenerative scrubbing of venturi off-gas with a proprietary amine, yielding a sulfuric acid by-product.

Dry FGD Processes

Approximately 64 percent of the SO₂ emissions in the United States are produced by the electric power generating units that burn fossil fuels, predominantly coal.³ Consequently, the majority of the FGD processes in use today have been designed to address SO₂ emission reductions from these electric generating units. The nodulizing kiln at the P4 facility is unlike an electric power generating unit and some of the FGD processes developed for coal combustion units are not technically feasible. Specifically, technically infeasible processes include those that involve injection of sorbent into the combustion chamber. The feed to the kiln is closely regulated to produce nodules that are usable in the furnaces. The addition of lime or limestone into the combustion chamber of the nodulizing kiln is not compatible with the process of nodule preparation and, is therefore, deemed to be technically infeasible. Any SO₂ removal process that utilizes injection of sorbent into the combustion chamber such as FSI and its variations were eliminated from further consideration.

5.1.3 Evaluate Control Effectiveness for Remaining Technologies

All remaining control technologies are capable of removal efficiencies of 97%. The remaining SO₂ control technologies are:

Once-Through Wet FGD Processes:

- LSFO,
- LCDA, and
- Ammonia Scrubbing.

Regenerative Processes:

- Amine scrubbing.

5.1.4 Evaluate Control Technology Impacts

5.1.4.1 Cost of Compliance

BART analyses require a baseline case for the emission unit be selected as a reference point for comparison of alternatives. This baseline case represents a realistic scenario of the upper boundary of uncontrolled emissions from the source. The 2001- 2002 actual emission were chosen for this scenario. This emission rate of 11,914 tons per year was based on P4's Enoch Mine phosphate ore composition, kiln on-stream time, and total daily feed to the kiln for 2001-2002. Cost effectiveness calculations were based on this baseline emissions value.

A summary of the cost effectiveness of each remaining technology is presented below:

Table 5.1.1 COST COMPARISON FOR SO₂ CONTROLS FOR THE #5 KILN

Scrubbing Technology	Initial Capital Costs (\$x10 ⁶ /yr)	Annual O&M ^a costs (\$x10 ⁶ /yr)	Total Annualized cost ^b (\$x10 ⁶ /yr)	Annualized cost per ton of SO ₂ removed (\$/ton SO ₂)
LSFO	21.2	4.4	7.42	\$642
LCDA	12.2	3.7	5.44	\$466
Ammonia Scrubbing	28.7	6.1	10.20	\$881
Regenerative Amine Scrubbing	30.3	5.5	9.81	\$849
a. O&M – operations and maintenance b. 7% discount rate over 10 years				

Cost effectiveness calculations are detailed in Appendix H to P4’s revised permit to construct application submitted on June 11, 2009. Operation and maintenance costs include operating labor, maintenance labor and materials, reagents, disposal of residuals, and energy.

The cost comparisons shown in Table 5.1.1 reflect the annualized cost compared to having no SO₂ controls installed. As shown in the table, LCDA was estimated to have the lowest annualized cost per ton of SO₂ removed. However, P4 is currently required to operate its existing LCDA scrubbing system whenever the kiln is operating. Because each of the SO₂ control technologies shown in the table have similar maximum control efficiencies of about 97%, the incremental cost of replacing the existing LCDA scrubbing system with a different system—even if higher control efficiencies could be reached—would be excessive.

5.1.4.2 Energy Impacts

Energy impacts from a control technology generally occur in one of two ways. First, if the flue gas temperature needs to be elevated in order for the control technology to work most efficiently, the cost of heating may be so large that it negatively impacts the cost effective of this control option. Second, if the energy cost (i.e., electric power) for operating a control technology is a disproportionately large part of the overall operation costs, compared to another technology given the same removal efficiency, the latter technology would be chosen as BART. Conversely, a control technology that uses less energy than the baseline condition would be looked upon more favorably than one that does not, given identical removal efficiencies. Both of these types of impacts are discussed in the cost effectiveness section.

None of the technically feasible technologies requires reheat of the flue gas or has disproportionate energy costs during operations. All will use more energy than the existing operation.

5.1.4.3 Non-Air Quality Environmental Impacts

Environmental considerations in a BART analysis concentrate on impacts other than on air quality from the pollutant under consideration. The focus is on impacts to solid or hazardous waste generation, discharges of pollutants to water, or emissions of pollutants not directly considered in the analysis. The LSFO process produces a solid gypsum by-product (after dewatering). This by-product can usually be disposed of in a non-hazardous waste landfill or, if market conditions are favorable, sold as a raw material. This process then has the potential positive environmental benefit of reusing the by-product as a raw material. One possible negative impact is the generation of fugitive dust from limestone stockpiles if these are not properly managed.

In the LCDA process, SO₂ is absorbed by a solution of sodium sulfite and sodium bisulfate. The spent sodium sulfite/bisulfite/sulfate solution is continuously withdrawn to a dual-reactor system where it is reacted with lime. The lime regenerates the scrubbing solution and precipitates calcium sulfite/sulfate solids. The filter cake resulting from dewatering the solids may be disposed of in a permitted, lined

landfill. The use of ammonia scrubbing has the potential positive environmental benefit of reusing the by-product (ammonium bisulfite/sulfite solution) as a raw material. Regenerative amine scrubbing produces liquid sulfuric acid as a by-product. This presents potential health and safety concern regarding the handling and storage of this material. With proper health and safety procedures, and a stable market for sulfuric acid sales, these environmental impacts will be significantly reduced.

5.1.4.4 Remaining Useful Life

The #5 Kiln is expected to remain in service for the life of the P4 facility. This criterion is not a factor in determining BART.

5.1.5 SO₂ BART for the Nodulizing Kiln (#5 Kiln)

Since all four remaining technologies are capable of 97% removal from baseline condition, the balancing factors of environmental, energy, and economic impacts would dictate the chosen technology. Based on the evaluation above, LCDA was selected by P4 as the preferred alternative for SO₂ control for the kiln emissions. It had the lowest cost per ton of SO₂ removed, a low probability of causing significant environmental impacts, and was a proven, mature technology. It was also compatible with the existing Hydro-Sonic© scrubbers that would continue to be used to control particulate/radionuclide emissions. The evaluation in this subsection was based on a comparison of control technologies versus no controls, and demonstrates that an LCDA scrubbing system would be selected as BART if the facility had no SO₂ controls on the kiln emissions.

P4 is currently required to limit coal sulfur content to a maximum of 1% by weight, and to operate its existing LCDA scrubbing system whenever the kiln is operating. The LCDA scrubbing system is expected to have a control efficiency of 97% for SO₂, which is reflected in the emissions estimates for this pollutant. The requirement to control SO₂ emissions contained in the 2002 DEQ consent order will be made federally-enforceable by incorporation into a permit to construct a Tier II operating permit.

5.2 Kiln PM/PM₁₀ BART Analysis

5.2.1 Identify Control Technologies

In response to a request from DEQ, P4 identified all technically available kiln particulate pollution control technologies in September 2006. The control technologies were evaluated and determined to be either technically feasible or infeasible.

The current particulate pollution control equipment on the kiln consists of a dust knockout chamber, spray tower, four parallel high-energy tandem nozzle venturi scrubbers, and eight parallel cyclonic separators. The venturi scrubbers were brought on-line in September 1987 in response to a January 1986 Consent Order. A BACT analysis was not performed during the pollution control selection process, however pilot plant tests were performed on three (3) different technologies: venturi scrubber, catenary grid scrubber, and wet electrostatic precipitator (ESP). These technologies are included in the list below.

The following is a list of the available control technologies (in approximately top-down order, i.e., technologies with better control efficiencies are listed first) from the pilot plant testing and RBL search that was performed in September 2006.

- Baghouse/Fabric Filter,

- Electrostatic Precipitator (ESP),
- Venturi Scrubber,
- Wet ESP,
- Rotoclone Scrubber,
- Catenary Grid Scrubber,
- Packed Scrubber, and
- Good Combustion Control.

5.2.2 Eliminate Technically Infeasible Options

Baghouse/Fabric Filter: This technology is best used in a dry environment. In a moist environment, the fabric can become blinded and the hopper can be bridged. The kiln exhaust gas is a moisture-laden stream because it is first sent through a spray tower to cool the gas stream from approximately 800 °C to 71 °C (1472°F to 160 °F).

ESP: This technology is technically infeasible for the same reasons as a baghouse/fabric filter.

Rotoclone Scrubber: This type of centrifugal or dynamic scrubber is considered a medium energy (medium pressure drop) scrubber and does not have the particulate removal efficiency of a high-energy scrubber. This technology does not have the control efficiency for sub-micron particulate matter that is needed in this application.

Packed Scrubber: The normal use for this technology is for the removal of gases and vapors from a gas stream; however, some types have been used for particulate removal. Coarsely packed beds are very effective at removing coarse dusts and mists. Finely packed beds may be used to remove smaller particulates, but because of pressure drop considerations, the velocity must be kept relatively low. Therefore, finely packed beds have a greater tendency to plug and are generally limited to gas streams with relatively low grain loading.

Catenary Grid Scrubber: P4 conducted a pilot plant test on a slipstream of kiln exhaust gas. The technology was susceptible to plugging of the straightening vanes, and fan vibrations due to buildup. The pilot plant test showed that the scrubber was effective at removing larger particles, but not sub-micron material. Therefore, this technology was not recommended for use in this application.

Good Combustion Control: Combustion in the kiln is carefully controlled to ensure that the kiln temperature stays in the range at which sintering of the phosphate ore occurs, which is 1400°C – 1459°C (2552 °F – 2658°F). Good combustion controls generally focus on ensuring adequate mixing and providing excess air to promote complete combustion. Excess air tends to cool the combustion chamber and therefore requires more fuel to maintain the high temperatures necessary for sintering the ore. Good combustion control is not feasible in this application.

P4 determined that the following two options were technically feasible:

Wet ESP: A pilot plant test was performed on a slipstream of kiln exhaust gas. The pilot plant test showed that the wet ESP is capable of reducing particulate emissions to an acceptable level. However, the technology is susceptible to fouling, scaling, and plugging from raw water quality. During the testing, the ESP had to be shutdown every two weeks in order to clean the plates and troughs of buildup and sedimentation.

Venturi Scrubber: A pilot plant test was performed on a slipstream of kiln exhaust gas. The pilot plant test showed that the tandem nozzle venturi scrubber was capable of reducing particulate emissions to an acceptable level with some nozzle plugging occurring. However, the problem was eliminated by adding water upstream of the first nozzle to wet the throat area of the nozzle. Venturi scrubber outlet emissions were insensitive to changes in inlet particulate loading, and water solids concentrations had no significant impact on particulate emissions.

5.2.3 Evaluate Control Effectiveness for Remaining Technologies

Wet ESP: On the pilot plant test, the wet ESP was found to have a particulate removal efficiency of approximately 93%. However, with the maintenance problems associated with this technology, it was not recommended for use in this application.

Venturi Scrubber: On the pilot plant test, the tandem nozzle venturi scrubber was found to have a particulate removal efficiency of approximately 95%. Therefore, high-energy tandem nozzle venturi scrubbers were recommended and installed on the kiln to control particulate emissions.

5.2.4 Evaluate Control Technology Impacts

As shown in Table 2.1, PTE emissions of SO₂ and NO_x from the #5 Kiln are substantially greater than estimated PM₁₀ emissions. SO₂ emissions are about seven times higher, and NO_x emissions are almost 42 times larger. Because P4 selected the most stringent technically-feasible option available in 1987 (the HE venturi scrubbers), the following impacts were not evaluated:

- 1) Cost of Compliance,
- 2) Energy Impacts,
- 3) Non-air Quality Environmental Impacts, and
- 4) Remaining Useful Life.

5.2.5 PM/PM₁₀ BART for the Nodulizing Kiln (#5 Kiln)

The evaluation in this subsection was based on a comparison of RBLC control technologies identified in 2006 versus no controls. Since 2006, there have been no additional technically-feasible controls identified with greater control efficiency than the HE venturi scrubbers already installed to control particulate emissions from the kiln.

P4 is currently required to use a dust knockout chamber, spray tower, high-energy tandem nozzle venturis, and cyclonic separators to control PM/PM₁₀ emissions from the kiln.

If a new technically feasible PM/PM₁₀ control technology were identified that has control efficiency greater than 95%, the relatively low level of PM/PM₁₀ emissions would cause the incremental cost of replacing the existing group of control devices to be excessive. No additional PM/PM₁₀ controls are needed to meet BART criteria.

5.3 Kiln NO_x BART Analysis

5.3.1 Identify Control Technologies

NO_x is formed in the kiln almost exclusively as thermal NO_x due to the high temperatures required to sinter the phosphate ore into nodules. NO_x is also formed when either coal or natural gas is used to supplement or replace the CO normally used to fire the kiln.

P4 conducted a search of EPA's RBLC Clearinghouse database for potential BART options for the control of NO_x emissions from large rotary kilns. The following is a list of the available control technologies that were identified:

- Good combustion control,
- Low NO_x burner, and
- Selective non-catalytic reduction (SNCR).

5.3.2 Eliminate Technically Infeasible Options

Good Combustion Practices: The temperature at which thermal NO_x is formed is approximately 1300°C (2372°F). The temperature at which sintering of the phosphate ore occurs is 1400°C to 1459°C (2552°F to 2658°F). Therefore, it is not feasible to lower the temperature in the kiln to minimize or prevent the formation of thermal NO_x.

Low NO_x Burner, Limit Excess Air: The temperature required for a low NO_x burner is too low to sinter the phosphate ore and form the required nodules. Sintering of the ore takes place at 1400°C to 1459°C, and low NO_x burners must be controlled to operate at temperatures well below 1300 °C (2372 °F), the temperature at which thermal NO_x is formed.

Selective catalytic reduction: Not included in the RBLC. If a SCR system were installed at the back end of the kiln prior to the particulate control system, the heavy particulate loading in the gas stream would foul the catalyst. Also, the temperature of the kiln offgas would be much too high for SCR to be effective. SCR is only effective in a temperature range of 300°C to 400°C (572 °F to 752 °F). If the SCR system were installed after the particulate control system to prevent catalysts fouling, the temperature of the gas stream would be too low for SCR to function properly. Also, the high moisture content in the gas stream after the particulate control system would cause the SCR system to be inoperable due to water molecules coating the surface of the catalyst and preventing mass transfer for the catalytic reaction to occur.

Selective Non-catalytic Reduction, Low NO_x Burners, top Air Duct: SNCR technology utilizes a reducing agent, the most popular being ammonia, in the gas stream at temperatures between 900 °C and 1000°C (1652 °F to 1832 °F) for optimum NO_x control. The kiln off gas temperature at the exit of the kiln is between 730 °C and 900 °C (1346 °F to 1652 °F), with the normal temperature being 750 °C (1382 °F). This is well below the minimum required temperature for SNCR to work effectively. Also, the existing ductwork, refractory, and waste heat boiler are not capable of handling gas streams at these temperatures for sustained periods of time. The heavy particulate loading in the kiln off gas stream would make it difficult to inject the liquid ammonia without plugging the spray injectors, and also may hinder the ammonia and NO_x chemical reaction by adsorption on the dust particles. P4's existing process layout would likely not allow enough room for the needed auxiliary burners and SNCR control equipment. If

SNCR were installed after the particulate control system, the temperature of the gas stream as it exits the particulate control system (approximately 80°C or 176°F) would be too low for the control system to function properly.

5.3.3 NO_x BART for the Nodulizing Kiln (#5 Kiln)

As demonstrated in the evaluation in this subsection, the required operating temperature range in the #5 Kiln precludes using typical NO_x control technologies. There are no technically feasible retrofit control technologies to control NO_x from the #5 kiln.

6. BART Analysis for the #9 Furnace and #9 CO Flare

Nodules from the #5 Kiln are combined with coke and quartzite and heated (in a reducing environment) in one of three electric furnaces. This reaction results in the production of phosphorus gas, along with CO and entrained particulate matter. The furnace off gas, composed primarily of CO, water, and trace quantities of fluoride, phosphorus, phosphorous compounds, and particulate matter, is sent to the #5 Kiln where the CO is used as fuel for the kiln.

At times, there may be more CO produced than can be burned in the kiln. The current PTC action is addressing BACT for this excess CO production.

Pursuant to a December 30, 2002 Consent Order issued by DEQ, P4 is required to implement BACT for the #7 furnace CO emissions or install a thermal oxidizer, whichever is more effective in reducing CO emissions. P4 is also required to apply such CO control technology on the #8 and #9 furnaces. P4 submitted a CO BACT analysis for the #7 Furnace and #7/8 CO Flare as part of the revised permit to construct application submitted on June 11, 2009.

Emissions from furnace slag tapping and the process stream ESP dust oxidation chamber from each furnace are controlled by a cyclonic separator and venturi scrubber known as the #7, #8, and #9 Furnace Tap Hole Fume Collectors (THFC).

Furnace pressure relief vessel vent gases are currently vented directly to the atmosphere through each furnace vent stack when the furnace is shut down. In the revised permit to construct application submitted on June 11, 2009, P4 proposed routing these emissions through the THFCs.

Because the #7 furnace process is representative of all three furnaces, the BACT analysis completed by P4 for the #7 furnace as part of the revised permit to construct application was used as the starting point for the BART analysis for the #9 Furnace and #9 CO Flare. The #9 Furnace is the largest of the three furnaces, but the operations are essentially the same as the #7 furnace and #7/8 CO Flare.

6.1 #9 Furnace and #9 Flare SO₂ BART Analysis

SO₂ emissions points associated with the #9 Furnace and #9 CO Flare include:

- #9 Furnace Vent Riser (P4 has proposed routing these emissions to the THFC stack): 2.35 T/yr
- #9 Furnace THFC Stack (ferrophosphorus and calcium silicate slag tapping): 48.48 T/yr
- #9 Furnace Treater Heat Vent (natural gas burner): 0.03 T/yr
- #9 Furnace Explosion Seal Vent (upsets only): 1.05 T/yr

Total SO₂ emissions associated with the #9 Furnace have been estimated (3/25/09 P4 emissions inventory). The potential to emit SO₂ from the three furnaces with CO BACT is 138 tons per year.

This BART analysis will focus on the two major sources of SO₂ for the furnace (the THFC stack and the #9 CO Flare).

6.1.1 Identify Control Technologies

#9 THFC

Available technologies for removing SO₂ from a gas stream are described in Section 5.1.1 for the #5 Kiln.

#9 CO Flare:

The RBLC database was searched for recent BACT determinations for SO₂ control on flares. Four facilities and 27 processes were found. The industries found were: Petroleum/Natural Gas Production and Refining, Municipal Waste, and Chemical Manufacturing. In each entry, the control listed was “pollution prevention.” These pollution prevention measures involved process controls that limit the sulfur content of the flare feed.

6.1.2 Eliminate Technically Infeasible Options

#9 THFC

A detailed review of technical feasibility for all of the available technologies listed in Section 5.1.1 was not conducted. The SO₂ emissions from the THFC stack are relatively small (~50 T/yr, if the furnace vent gases are rerouted to this stack). Installing new SO₂ controls for this waste stream will not be economically feasible.

#9 CO Flare:

Process Controls: The process controls described in the RBLC database for flares included the use of low-sulfur fuel burned at the flare or a reduction in sulfur content of a feedstock for a process upstream of the flare. The production of elemental phosphorus in the #9 Furnace is a highly controlled process. The furnace is operated to optimize the production of elemental phosphorus. This production process does not directly depend on a fossil fuel source or other controllable sulfur-containing feed material. Therefore, process controls to reduce the sulfur in the waste gas to the flare for SO₂ control are technically infeasible for the #9 CO flare.

6.1.3 Evaluate Effectiveness for Remaining Control Technologies

There are no technically feasible options for controlling SO₂ emissions from the #9 furnace (including the #9 CO flare).

6.1.4 Evaluate Control Technology Impacts

There are no technically feasible options for controlling SO₂ emissions from the #9 furnace (including the #9 CO flare).

6.1.5 SO₂ BART for #9 Furnace and #9 CO Flare

There are no technically feasible options for controlling SO₂ emissions from the #9 furnace (including the #9 CO flare).

None of the control technologies identified for SO₂ control are technically feasible on the #9 CO flare. BART for the #9 CO Flare is “no additional controls.”

6.2 #9 Furnace and #9 Flare PM BART Analysis

Particulate emissions points associated with the #9 Furnace and #9 CO Flare include:

- #9 Furnace Vent Riser (P4 has proposed routing these emissions to the THFC stack): 6.58 T/yr
- #9 Furnace THFC Stack (ferrophosphorus and calcium silicate slag tapping): 26.28 T/yr
- #9 Furnace Treater Heat Vent (natural gas burner): 0.58 T/yr
- #9 Furnace Explosion Seal Vent (upsets only): 0.003 T/yr

The potential to emit PM from the three furnaces is 155 tons per year.

This BART analysis will focus on the two major sources of PM₁₀ for the furnace (the THFC stack and the #9 CO Flare).

6.2.1 Identify Control Technologies

#9 THFC

Particulate emissions from #9 Furnace slag tapping and the ESP dust oxidation chamber are currently controlled by a cyclonic separator and venturi scrubber known as the #9 Furnace THFC.

#9 Furnace pressure relief vessel vent gases are currently vented directly to the atmosphere through the #9 Furnace vent stack when the furnace is shut down. In the revised permit to construct application submitted on June 11, 2009, P4 proposed routing these emissions through the THFC.

Available technologies for removing PM from a gas stream, in top-down order, include:

	<u>Total PM</u>	<u>PM <0.3µm</u>
• Baghouse/Fabric Filter:	98 to 99.9%	99 to 99.98%
• ESP:	99 to 99.7%	80 to 95%
• Particle Scrubber	95 to 99%	30 to 85%
– High energy (e.g., venturi)		
– Medium energy		
– Low energy (e.g., spray tower)		
• Mechanical Collector (e.g., cyclone)	70 to 90%	0 to 15%

#9 CO Flare:

P4 queried the RBLIC for a process type that included the word "flare" and "PM" as the pollutant. The search yielded 23 facilities with 32 processes. Of these 23 facilities, seven were chemical or plastics manufacturing facilities, four were crude oil refineries, four were landfills, three were oil exploration operations, three were natural gas treating facilities, one was a steel foundry and one was a grain processing plant. Databases from several California regulatory bodies and the Texas Commission on Environmental Quality (formerly the Texas Natural Resource Conservation Commission) were also queried for updated flare BACT information compared to the extensive discussion in the SENES BACT (2002a). No new information was found.

The most common control technologies for PM for flares in the RBLIC were good combustion practices (smokeless flare) or proper operation. One included steam-assisted combustion (from a vacuum tank degasser in a steel foundry). This enhancement reportedly increases the efficiency of flares by providing better mixing with combustion air. The gas streams burned at all of these facilities have a higher heating value and higher VOC content than the gas stream from the P4 furnaces (which is about 300 Btu/scf). None of these facilities burned CO in their flare; therefore, none of these BACT determinations are directly applicable to the P4 furnaces.

6.2.2 Eliminate Technically Infeasible Options

#9 THFC

A detailed review of technical feasibility for the available PM control technologies was not conducted. The PM/PM₁₀ emissions from the THFC stack are relatively small (~33 T/yr, if the furnace vent gases are rerouted to this stack). Installing new or retrofit PM controls for this waste stream will not be economically feasible.

#9 CO Flare:

No retrofit options for controlling PM emissions from flares have been identified.

6.2.3 Evaluate Control Effectiveness for Remaining Technologies

There are no technically feasible options for controlling PM emissions from #9 furnace (including the #9 CO flare).

6.2.4 Evaluate Control Technology Impacts

There are no technically feasible options for controlling PM emissions from #9 furnace (including the #9 CO flare).

6.2.5 PM BART for #9 Furnace and #9 CO Flare

#9 THFC

PM BART for the #9 Furnace Vent is to reroute the #9 Furnace vent emissions through the THFC. Because the emissions from the THFC stack already pass through a cyclonic separator and venturi scrubber, and because the PM/PM₁₀ emissions are quite low (~33 T/yr), PM BART for the THFC is “no additional controls.”

#9 CO Flare:

No retrofit control technologies were identified for PM control on the #9 CO flare. PM BART for the #9 CO Flare is “no additional controls.”

6.3 #9 Furnace and #9 CO Flare NO_x BART Analysis

6.3.1 Identify Control Technologies

NO_x emissions points associated with the #9 Furnace include:

- #9 Furnace Vent Riser (P4 has proposed routing these emissions to the THFC stack): 0.75 T/yr
- #9 Furnace THFC Stack (ferrophosphorus and calcium silicate slag tapping): not estimated
- #9 Furnace Treater Heat Vent (natural gas burner): 4.83 T/yr
- #9 Furnace Explosion Seal Vent (upsets only): 0.0056 T/yr

The potential to emit NO_x emissions from the three furnaces is 119 tons per year.

This BART analysis will focus on the two major sources of NO_x for the furnace (the THFC stack and the #9 CO Flare).

#9 THFC

NO_x from #9 THFC are currently uncontrolled.

#9 Furnace pressure relief vessel vent gases are currently vented directly to the atmosphere through the #9 Furnace vent stack when the furnace is shut down. In the revised permit to construct application submitted on June 11, 2009, P4 proposed routing these emissions through the THFC.

Available technologies for removing NO_x from a gas stream include:

- Low NO_x burner,
- Overfire Air,
- Reburning,
- Flue Gas Recirculation,
- SCR,
- Selective non-catalytic reduction (SNCR),
- Good combustion control.

#9 CO Flare:

P4 searched the RBLC database for recent BACT determinations for NO_x control from flares. Twenty-one entries for NO_x were found. The industries found were Petroleum/Natural Gas Production and Refining, Municipal Waste, Utility and Large/Industrial-Size Boilers, Commercial/Institutional-Size Boilers, Miscellaneous Combustion, and Chemical Manufacturing. The NO_x controls found were listed as: “no controls feasible,” “general control device requirements,” (refers to 40 CFR §60.18 and §63.11) and “good design and proper operating practices.”

As discussed in the SENES BACT analyses, steam injection is a technology that is used on flares to help prevent smoking and to improve the overall efficiency of the flare. Injection of steam is widely used as a standard operating procedure on VOC flares to create turbulent mixing of air and the fuel for more complete combustion and to provide some cooling of the flare tip and stack.

6.3.2 Eliminate Technically Infeasible Options

#9 THFC

A detailed review of technical feasibility for the available NO_x control technologies was not conducted. The NO_x emissions from the THFC stack are relatively small (~23 T/yr, if the furnace vent gases are rerouted to this stack). Installing new or retrofit NO_x controls for this waste stream will not be economically feasible.

#9 CO Flare:

None of the NO_x controls found in the RBLC or elsewhere apply to flares that use CO as their primary fuel. These flares burned volatile organic compounds (VOC), landfill gas, refinery fuel gas, natural gas, or other hydrocarbon-derived fuel. Therefore, none of the process controls or BACT emissions limits identified in the RBLC are directly applicable to the No.7/8 CO Flare. In addition, the fuels that are combusted in most of the flares found in the RBLC or elsewhere have a higher heat input than CO giving these flares a hotter peak temperature and, therefore, a higher NO_x emission rate per unit of fuel gas than the No.7/8 CO flare.

Good design as a control technology applies to new flares and is not an economically feasible retrofit option. Installing new or retrofit NO_x controls for this waste stream will not be economically feasible.

6.3.3 Evaluate Control Effectiveness for Remaining Technologies

There are no technically feasible options for controlling NO_x emissions from #9 furnace (including the #9 CO flare).

6.3.4 Evaluate Control Technology Impacts

There are no technically feasible options for controlling NO_x emissions from #9 furnace (including the #9 CO flare).

6.3.5 NO_x BART for #9 Furnace and #9 CO Flare

#9 THFC

Because the NO_x emissions are quite low (~23 T/yr), NO_x BART for the #9 THFC is “no additional controls.”

#9 CO Flare:

No retrofit control technologies were identified for NO_x control on the #9 CO Flare. NO_x BART for the #9 CO Flare is “no additional controls.”

Appendix A – RBLC Summaries

RBLC (RACT-BACT-LAER Clearinghouse) Report for NOx Control on Kilns
 Report Date: 8/26/2006

#	Date	Company	Facility	Location	Process Unit	NOx Control	Other Limits
1	8/24/2006	Western Greenbrier Co-Generation, LLC	Western Greenbrier Co-Generation, LLC	WV	Cementitious Material Kiln		
2	8/3/2006	Georgia Pacific Corp	Monticello Mill	MS	Lime Kiln	Good Combustion Practices	
3	10/25/2004	Graymont PA Inc	Graymont Bellefonte Plant	PA	#7 Lime Kiln		
4	8/29/2006	Western Lime Corporation	Western Lime Corporation	MI	Lime Kiln	Low NOx Burner, Limit Excess Air	
5	6/21/2005	Pope & Talbot	Halsey Pulp Mill	OR	Lime Kiln	Good Combustion Control	
6	1/17/2006	Hoeganaes Corp	Hoeganaes Corp	TN	Rotary Kiln	Proper Combustion Control	Operating hours are limited to 8,000 hours/12 consecutive months
7	11/16/2005	Georgia Pacific Corp	Monticello Mill	MS	Lime Kiln	Good Combustion Practices, Kiln Design	
8	1/12/2004	Roanoke Cement	Roanoke Cement	VA	Lime Kiln	Good Combustion Practices	CEMS
9	10/10/2003	Weyerhaeuser	Flint River Operations	GA	Rotary Lime Kiln		
10	9/17/2003	Vulcan Materials	Vulcan Materials	IL	Lime Kiln	Best Combustion Practices	
11	9/17/2003	Continental Cement Company	Continental Cement Company	MO	Rotary Kiln & Pyroprocessing System	Selective Non-catalytic Reduction, Low NOx Burners, Top Air Duct	
12	1/3/2003	LaFarge Corp	LaFarge Corp	IA	Kiln	Good Combustion Practices	
13	3/12/2004	Carolina Stalite Company	Gold Hill	NC	Rotary Expanding Kiln	Good Combustion Techniques	
14	3/17/2005	International Paper	Mansfield Mill	LA	Lime Kiln	Good Process Controls	Water content of lime
15	1/4/2005	Donahue Industries	Donahue Industries Paper Mill	TX	Lime Kiln		
16	9/18/2001	Lehigh Portland Cement Company	Lehigh Portland Cement Company	MD	Preheater/Preclinker Kiln	5-stage preheater/preclinker pyroprocessing plant	Any add-on Nnx emissions control has been determined to be either technically or environmentally infeasible
17	9/22/1998	Holnam, Laporte Co.	Holnam, Laporte Co.	CO	Caliner/Kiln	Special Process: Design of burner/kiln to control alkali from limestone	
18	12/4/2001	Signal Mountain Cement Co, LP	Signal Mountain Cement Co, LP	TN	Dry Feed Kiln	Good Combustion Practices	
19	1/4/2005	Chemical Lime, LTD	Lime Plant	TX	Kiln		
20	6/6/2002	Ash Grove Cement Co.	Ash Grove Cement Co.	UT	Kiln	Low NOx Burner	400 lb/hr at 80% of max production capacity
21	10/7/2002	Weyerhaeuser Co.	Weyerhaeuser Co.	MS	Lime Kiln	Effective operation of kiln	
22	12/4/2002	Westvaco Corp., Chemical Division	Westvaco Corp., Chemical Division	KY	Woodbase Carbon Acid/Mixing, Activation Kiln	Low NOx Burner	
23	3/3/2004	Holnam, Devil's Slide Plant	Holnam, Devil's Slide Plant	UT	Kiln	Low NOx Burner	
24	9/17/2002	Willamette Industries	Mariboro Mill	SC	Kiln	Good Combustion Control	

NOTE: NOx Control column = blank: original RBLC report had (N)

RBLIC (RACT-BACT-LAER Clearinghouse) Report for NOx Control on Flares
 Report Date: 5/10/2006

#	Date	Company	Facility	Location	Process Unit	NOx Control	Other Limits
1	12/21/2005	New England Waste Services, Inc.	New England Waste Services of Vermont, Inc.	VT	Landfill Gas Flare	NO2 emissions: Low emissions design	
2	10/25/2004	Steelcon, Inc.	Bluewater Project	AR	Degasser Hotwell Flare		
3	7/5/2005	Charger Manufacturing Co., Inc.	Charger Steel	OH	Vacuum Oxygen Degasser Vessel w/Flare		Emissions from NG combustion from flare; only during oxygen loading degassing process for low carbon and stainless steel production.
4	12/30/2004	Degussa Engineered Carbons LP	Baytown Carbon Black Plant	TX	Dryers, Boilers, Flare	Good combustion practice and design	
5	12/30/2004	Degussa Engineered Carbons Inc	Bogert Carbon Black Plant	TX	Dryers, Boilers, Flare	Good combustion practice and design	
6	10/28/2002	Conoco, Inc.	Porter City Refinery	OK	Flare	Limit fuel to pipeline grade natural gas	
7	4/6/2004	Valero Refining Company	Corpus Christi Refinery	TX	Main Flare		
					Ground Flare		
8	1/3/2005	Alofina Petrochemicals, Inc.	La Porte Polypropylene Plant	TX	Monument No. 2 Flare	None indicated	
					Train No. 8 Flare	None indicated	
9	1/3/2005	Reliant Energy, Inc.	Limestone Electric Generating Station	TX	FCCU Flare	None indicated	
					HCU Flare	None indicated	
10	1/5/2005	Exxon Mobil Chemical Company	Baytown Olefins Plant	TX	Primary Flare	None indicated	
					Secondary Flare	None indicated	
					Flare, Flarex	None indicated	
11	10/27/2005	City of LA, Bureau of Sanitation	City of LA, Bureau of Sanitation	CA	Landfill Gas Gathering System Flare		
12	1/3/2005	Vetrotex America	Saint-Gobain Vetrotex America	TX	Propane Flare	None indicated	
13	1/4/2005	Trefinery Petroleum Service	Trefinery Corpus Christi	TX	Flare, Flare	None indicated	
					Plant Flare	No NOx control listed	
14	1/4/2005	Vetrotex America	Vetrotex America	TX	Propane Flare	None indicated	
15	1/16/2004	Cabot Corporation	Wile Platte	LA	Units 1&2 Flare	Design and proper operation	
16	7/24/2003	Formosa Plastics Corp.	Formosa - High Density Polyethylene II	TX	Elevated Flare	None indicated	
17	8/30/2004	Exxon Chemical Company	Exxon Baytown Olefins Plant	TX	Secondary Flare		
18	7/3/2003	MCLUA Landfill Gas Utilization Project	MCLUA	NJ	Open Flare	None	
19	11/17/2004	Fina Oil & Chemical Company	Port Arthur Refinery	TX	Flare		
20	7/25/2003	Praxair Incorporated	Praxair Synthesis Gas Plant	TX	Flare	None indicated	
21	1/5/2005	Equistar Chemicals, LP	Equistar Chemicals, LP	TX	Cold Flare	None indicated	
22	10/28/2004	Fina Oil and Chemical Company	Port Arthur Refinery	TX	Flare		
23	8/30/2004	Fina Oil and Chemical Company	Alofina's Port Arthur Complex	TX	Flare		
24	10/25/2002	Grain Processing Corp.	Grain Processing Corp.	IN	Wastewater Treatment Plant Flare	Flare limited to 520 h/yr	
25	8/28/2003	Union Carbide Chem & Plastics Co. Inc.	Low Pressure Polyethylene Plant No. 2	TX	Large Flare		
					Small Flare	None indicated, BACT is applied.	
26	12/18/2001	City of Stockton Municipal Utilities Dept	City of Stockton Municipal Utilities Dept	CA	Digester Gas-Fired Flare	No control that is not integral to the flare	
27	9/16/2002	Chevron USA	Chevron USA	MS	SOCMI Distillation Process with Flare	NO2: Flare is used to reduce NOx emissions from the process	
28	1/4/2005	Formosa Plastics Corporation	Marine Loading Facility	TX	Deck Flare	None indicated	

Report for NO_x Control on Flares, continued

#	Date	Company	Facility	Location	Process Unit	NO _x Control	Other Limits
					FT-D18 Flare	None indicated	
					BTX Tank Flare	None indicated	
29	12/18/2001	Texaco Exploration and Production	Texaco Exploration and Production	CA	Guy-Wire Vertical Coanda-Effect Waste Gas Flare	Kaldair, Coanda Effect, electronic ignition	
30	4/11/2006	Westlake Petrochemicals Corp	Ethylene Manufacturing Complex Patrol B Unit	LA	Flare		Emission limits reflect those established by PSD-LA-595(M1). Limits unchanged by PSD-LA-595(M2).

NOTE: NO_x Control column = Blank; original RBLC report had (N) or (I)

RBLC (RACT-BACT-LAER Clearinghouse) Report for PM Control on Kilns – Report Date: 9/25/2006

#	Date	Company	Facility	Location	Process Unit	PM Control	Other Limits
1	8/16/2006	Cutler-Magner Company	CLM - Superior	WI	Lime Kiln	High temperature membrane (PTFE) fabric filter baghouse; preheater lime kiln	
2	6/28/2006	Big River Industries, Inc.	Gravelite Division	LA	Nos 1-4 Rotary Kilns	Venturi Scrubber	
3	6/19/2006	US Gypsum Company	US Gypsum Company	VA	Drying Kiln		
4	5/24/2006	Weyerhaeuser, Inc.	Red River Mill	LA	Lime Kiln No. 2	Electrostatic Precipitator (ESP)	
5	4/26/2006	Western Greenbrier Co-Generation, L.L.C.	Western Greenbrier Co-Generation, L.L.C.	WV	Cementitious Material Kiln	Baghouse	Kiln exhaust combined with CFB exhaust and emitted from a common stack
6	3/30/2006	Suwanne American Cement	Branford Cement Plant	FL	Kiln w/In-Line Raw Mill	Baghouse	
7	1/25/2006	Sierra Pacific Industries	Skagit County Lumber Mill	WA	7 Dry Kilns		
8	10/21/2005	Dalitalia, L.L.C.	Muskogee Porcelain Floor Tile Plant	OK	Kilns	Use of natural gas fuel	
9	10/14/2005	Dalitalia, L.L.C.	Muskogee Porcelain Floor Tile Plant	OK	Kilns	Wet Scrubber	
10	8/30/2005	Arkansas Lime Company	Arkansas Lime Company	AR	Lime Kiln, SN-30Q	Baghouse	
11	3/4/2005	Georgia Pacific Corporation	Monticello Mill	MS	Lime Kiln	Venturi Scrubber	
12	12/20/2004	Florida Crushed Stone Company	Brooksville Cement Plant (FCS)	FL	Clinker Kiln	Baghouse	
13	11/5/2004	Florida Rock Industries, Inc.	Thompson S. Baker - Cement Plant (FRI)	FL	In Line Kiln/ Raw Mill	ESP	
14	10/25/2004	Graymont PA Inc	Graymont Bellefonte Plant	PA	#6 Lime Kiln, #7 Lime Kiln	Fabric Filters	
15	6/29/2006	Western Lime Corporation	Western Lime Corporation	MI	Lime Kiln	Fabric Filters	Use of propane or No. 2 Oil with no stone feed on startup
16	9/29/2005	Lehigh Cement Company	Lehigh Cement Company	IA	Kiln /Calcliner/Preheater	ESP	
17	7/18/2005	Carmeuse Liome, Inc.	Maple Grove Gacility	OH	Rotary Kiln (2)	Baghouse	
18	8/30/2006	Georgia Pacific Corporation	Monticello Mill	MS	Lime Kiln	Scrubber	
19	8/31/2006	Roanoke Cement	Roanoke Cement	VA	Lime Kiln	Electrostatic Precipitators & Good Combustion Practices	
20	10/10/2003	Weyerhaeuser - Flint River Operations	Weyerhaeuser - Flint River Operations	GA	Rotary Lime Kiln	ESP	
21	9/5/2003	GCC Dacotah	GCC Dacotah	SD	Rotary Kiln #6	Fabric Filters	
22	4/6/2005	Georgia-Pacific Corp.	El Dorado Sawmill	AR	Lumber Drying Kiln	Proper Maintenance and Operation	

#	Date	Company	Facility	Location	Process Unit	PM Control	Other Limits
23	9/17/2003	Vulcan Materials	Vulcan Materials	IL	Lime Kiln	Baghouse	
24	9/17/2003	Continental Cement Company	Continental Cement Company, L.L.C.	MO	Rotray Kiln	Fabric Filters	
25	1/3/2003	LaFarge Corporation	LaFarge Corporation	IA	Preheater/Precalciner Kiln	Baghouse	
26	5/13/2004	Meadwestvaco Kentucky, Inc.	Meadwestvaco Kentucky, Inc/Wickliffe	KY	Lime Kiln	Scrubber	
27	3/2/2004	Georgia Pacific Corporation	Port Hudson Operations	LA	Lime Kiln No. 1	Wet Scrubbers	
28					Lime Kiln No. 2	ESP	
29	3/12/2004	Carolina Stalite Company	Gold Hill	NC	Rotary Expanding Kiln	Wet Lime Slurry Injection	
30	8/10/2005	Longview Fibre Company	Longview Fibre Company	WA	Lime Kilns 1, 2, 3, 4, and 5		
31	12/22/2003	Bowater	Bowater Coated Paper Division	SC	Lime Kiln, No. 2	ESP	
32	11/24/2003	Ash Grove Cement Company	Portland Cement Clinkering Plant	WA	Kiln Exhaust Stack	Baghouse	
33	9/25/2006	The Dow Chemical Company	The Dow Chemical Company	MI	Incinerator, Rotary Kiln, Hazardous Waste	Venturi Scrubber	
34	3/17/2005	International Paper	Mansfield Mill	LA	Lime Kiln	Venturi Scrubber using Caustic Solution	
35	1/5/2005	Alamo Cement Company II, LTD	Portland Cement Manufacturing Plant	TX	Grinding/Preheating Kiln, K-19	ESP	
36	5/17/2004	International Paper Company	Riegelwood Mill	NC	Lime Kiln	ESP and Fixed Throat Spray Venturi-Type Wet Scrubber	
37	8/22/2006	Crown Paper Company	St. Francisville Mill	LA	Lime Kiln, Emission Pt. RC-01	None Indicated	Stack tests will be conducted
38	4/6/2005	Weyerhaeuser Company	Weyerhaeuser Company	MS	Kilns, Dry Lumber, 5; AA-007	Good Combustion Control	AA-007: No controls feasible
39	8/14/2006	Donahue Industries, Inc.	Paper Mill	TX	Lime Kiln	Scrubber	
40	12/27/2001	Gulf Lumber Company	Mobile	AL	Dry Kilns; Lumber Dry Kilns	Good Engineering Practices	
41	3/2/2004	Rio Grande Portland Cement Corp.	Rio Grande Portland Cement Corp.	CO	Kiln, Clinker Cooler	High temperature fabric filter baghouse for clinker cooler	
42					Preheater/Precalciner, Kiln	High temperature filter baghouse	
43	1/4/2005	Temple-Inland Forest Products Corporation	Temple-Inland Pineland Manufacturing Complex	TX	(2) Kiln Drying, Studmills 1&2, EPN91&92	No Controls Required	
44					(4) Kilns 1-4, Drying, Sawmill, EPN101-104	No Controls Required	

#	Date	Company	Facility	Location	Process Unit	PM Control	Other Limits
45	9/18/2001	Lehigh Portland Cement Company	Lehigh Portland Cement Company	MD	Preheater/Precalciner Kiln	Enclosure, Wet Suppression Systems and Paved Roads	Control Efficiencies Range from 60-90%
46	12/9/2003	Suwanee American Cement Company, Inc.	Suwanee American Cement Company, Inc.	FL	In Line Kiln & Raw Mill	Baghouse	
47	2/10/2003	Arkansas Lime Company	Arkansas Lime Company	AR	Rotary Lime Kiln, No. 2	Baghouse	
48	12/18/2001	Watson town Brick Company	Watson town Brick Company	PA	Kiln, Brick Tunnel	Dustex, PDE-3630-14-40 Fabric Filter	Polymide Bags @ 2066/1 AC
49	3/11/2002	Holnam, Inc.	Holnam, Inc.	MI	Cement Kilns, Wet Process (2)	Fabrick Filter, Slurry Scrubber	
50	1/20/2005	Meadwestvaco Kentucky, Inc.	Wickliffe Carbon Plant	KY	Activation Kiln	Wet Fan, Reverse Jet Scrubber, and Brink Mist Eliminator	
51					Drying Kiln	Baghouse	
52					Activation Kiln	Rotoclone Scrubber	
53	1/4/2005	Texas Lime Co	Texas Lime	TX	Lime Kiln No 4 & No 6	None Indicated	
54	3/2/2004	Holnam, Florence	Holnam, Florence	CO	Kiln/Preheater/Bypass & Clinker Cooler Exhaust	Baghouse	
55	4/18/2002	General Shale Products Corp., L.L.C.	General Shale Products Corp., L.L.C.	AR	Kiln, Aggregate	Natural Gas Usage, Wet Scrubber, and Good Combustion	
56	3/10/2004	Lone Star Industries, Inc.	Lone Star Industries, Inc.	IN	Kiln Operation	ESP	
57	1/4/2005	North Texas Cement Company	North Texas Cement Company	TX	Main Kiln/Scrubber Stack	Scrubber and Baghouse	
58	1/4/2005	Champion International Corporation	Camden Complex	TX	(3) Kilns No 1-3, K-01 thru -03	None Indicated	
59	12/3/2003	Holnam, Laporte Co.	Holnam, Laporte Co.	CO	Calciner/Kiln	Baghouse	
60	5/20/2004	Lone Star Industries, Inc.	Lone Star Industries, Inc.	IN	Cement Kiln, Wet Process, Coal	ESP	
61	1/4/2005	Capitol Aggregates, LTD.	Capitol Cement Division	TX	Dry/Wet Kiln	Baghouse	
62	2/26/2003	IMC-Agrico Company	IMC-Agrico Company	FL	Kilns A, B	Packed Scrubber using Pond Water	
63					Kiln C	Caustic Solution Sprayed into Back of Wet Scrubber	
64	1/27/2003	Holnam, Inc.	Holnam, Inc.	MI	Cement Kilns, Wet Process (2)	Baghouse	
65	4/6/2005	Weyerhaeuser Company	Wright City Mill	OK	No. 3 Pine Lumber Kiln		
66	10/9/2002	Illinois Cement Company	Illinois Cement Company	IL	Kiln	Fabric Filter	

#	Date	Company	Facility	Location	Process Unit	PM Control	Other Limits
67	12/4/2001	Signal Mountain Cement Company, LP		TN	Dry Feed Kiln	Baghouse	
68	9/26/2002	Macmillan Bloedel Packaging	Macmillan Bloedel Packaging	AL	High Temp Lumber Kiln		
69	3/3/2004	Ash Grove Cement Compant	Durkee Facility	OR	Kiln	Baghouse	
70	4/25/2002	Palmetto Lime, L.L.C.	Palmetto Lime, L.L.C.	SC	Vertical Shaft Kilns	Baghouse	
71	12/18/2001	Continental Lime, Inc.	Continental Lime, Inc.	MT	Kiln-Lime, Two	Baghouse	
72	3/8/2002	Weyerhaeuser, Company		AL	Lumber Dry Kilns		
73	4/2/2004	Weyerhaeuser, Company	Greenville Sawmill	NC	Drying Kilns, 7		
74	1/4/2005	Chemical Lime LTD	Lime Plant	TX	Kiln	Baghouse	
75	2/24/2003	Southdown, Inc.	Southdown, Inc.	FL	Kiln 1, 2	Fabric Filters, Good Combustion	
76	8/28/2006	Casie Ecology Oil Salvage	Casie Ecology Oil Salvage	NJ	Kiln	Fabric Filter, Cyclone, Afterburner, Quench	
77	12/17/2003	Florida Rock Industries, Inc.	Florida Rock Industries, Inc.	FL	Kiln	ESP	
78	4/6/2005	Weyerhaeuser Company	Wright City	OK	No 4 Pine Lumber Mill		
79	6/6/2002	Ash Grove Cement Company	Ash Grove Cement Company	UT	Kiln	Baghouse	
80	4/6/2005	Hankins Lumber Company	Hankins Lumber Company	MS	Lumber Dry Kilns (5)		
81	10/7/2002	Weyerhaeuser Company	Weyerhaeuser Company	MS	Lime Kiln	ESP	
82	12/4/2002	Westvaco Corporation, Chemical Division	Westvaco Corporation, Chemical Division	KY	Activation Kiln	Venturi Scrubber	
83					Activation Kiln	Rotoclone Scrubber	
84	10/7/2002	Buckeye Florida, LP	Buckeye Florida, LP	FL	Lime Kiln	ESP	
85	12/4/2001	Western Lime Corporation	Western Lime Corporation	WI	Lime Kiln #2	Pulse-Jet Baghouse	
86	9/6/2002	Riverwood International Corporation	Riverwood International Corporation	GA	Kilns 1 & 2	Venturi Scrubber for each Kiln	
87	8/31/2006	Apple Grove Pulp and Paper Company, Inc.	Apple Grove Pulp and Paper Company, Inc.	WV	Lime Kilns (2)	Fabric Filter	
88	3/3/2004	Holnam, Inc.	Devils Slide Plant	UT	Kiln	Baghouse	
89	9/26/2002	Chemical Lime Company of Alabama, Inc.	O'Neal Quarry	AL	Kiln Dust Bin	Baghouse	
90	9/17/2002	Willamette Industries	Marlboro Plant	SC	Lime Kiln	ESP	
91	12/18/2001	Continental Lime Inc.	Cricket Mtn. Lime Plant	UT	Kiln #4	Baghouse	

NOTE: PM Control column = blank; original RBLC report had (N)

Appendix D – Facility Comments

Comment No. 1

Change four parallel cyclonic separators to eight parallel cyclonic separators.

Response to No. 1

According to an e-mail from P4 dated September 24, 2009, there have always been eight separators. The original Tier I application and permit were incorrect. There are two separators after each scrubber unit. These cyclonic liquid/gas separators operate in parallel. They are both in operation at the same time. The gas/water mixture coming out of the second stage of the venturi is split equally between the two separators. The separators coalesce and separate the water from the gas.

Based on this information, the permit and statement of basis were changed to show eight separators instead of four.