APPENDIX B
THE RACT DOCUMENTS FOR CARMEUSE, U.S. STEEL, DTE RIVER ROUGE AND TRENTON CHANNEL, AND EES COKE

SO_2 RACT REVIEW

Carmeuse Lime & Stone > River Rouge, MI

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TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

Carmeuse Lime & Stone (Carmeuse) owns and operates a lime manufacturing plant in River Rouge, Michigan (River Rouge Facility), consisting of two straight rotary kilns controlled by baghouses that emit through monovents (not traditional stacks) and ancillary equipment. To support development of a State Implementation Plan (SIP) for meeting the 1-hour sulfur dioxide (SO_2) National Ambient Air Quality Standards (NAAQS) in the newly designated nonattainment area in Southeast Michigan, the Michigan Department of Environmental Quality (DEQ), Air Quality Division (AQD), requested a SO_2 Reasonably Available Control Technology (RACT) analysis for the lime kilns at the River Rouge Facility. The following submittal reflects Carmeuse's RACT analysis in response to this request. Given that Carmeuse has only had a limited amount of time or prepare this response, we may supplement our response as needed as your rulemaking process proceeds forward.

2. BACKGROUND

In July 2013, the DEQ provided copies of dispersion modeling input files to Carmeuse.[1] These files were used in DEQ's initial modeling analyses to assess culpability for modeled exceedances of the 1-hour SO_2 NAAQS in the Detroit area. These files, along with presentations by DEQ dispersion modelers at Southeast Michigan Council of Government (SEMCOG) meetings in 2013, demonstrated that the River Rouge Facility is not a culpable contributor to monitored exceedances of the 1-hour SO_2 NAAQS at the Southwestern High School monitor. This monitor is the only monitor in the Detroit area at which concentrations in excess of the 1-hour SO_2 NAAQS were observed during 2009-2011, which is the time period used to make a nonattainment designation for the area. Ambient SO_2 concentrations in excess of the NAAQS have not been observed near the River Rouge Facility. However, the DEQ has asked that Carmeuse reduce ambient concentrations based on a "hotspot" dispersion modeling analysis, which showed based on computer model simulations that, under a combination of worst-case meteorological conditions and worst-case emissions from the River Rouge Facility, concentrations in excess of the NAAQS may be possible. Carmeuse does not believe that RACT is applicable to a source that has not been shown to contribute to monitored SO_2 NAAQS exceedances; nevertheless, we are cooperating with this request to submit an SO_2 RACT analysis for the lime kilns at the River Rouge Facility.

[1] Email from Ms. Stephanie Hengesbach of DEQ to Ms. Stacey Rader of Carmeuse, dated July 18, 2013.

3. RACT REVIEW

Requirements for RACT reviews are provided in the Clean Air Act and in guidance from the United States Environmental Protection Agency (USEPA). As provided in Michigan DEQ's letter requesting the RACT analysis[2],

> *Section 172 of the federal Clean Air Act sets out basic planning requirements for areas not meeting one or more NAAQS. One such plan requirement is the application of RACT controls to existing facilities in the nonattaining area. Subrule (c)(1) of Section 172 states: "Such plan provisions shall provide for the implementation of all reasonably available control measures as expeditiously as practicable (including such reductions in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology) and shall provide for attainment of the National Primary Ambient Air Quality Standards." Further, the {USEPA} says RACT means devices, systems, process modification, or other apparatus or techniques that are reasonably available, taking into account the necessity of imposing such controls in order to attain and maintain the NAAQS and the social, environmental, and economic impact of such controls.*

As outlined above, the sole intent of the RACT review is to establish a reduction strategies for an existing source in a nonattainment area in order to attain and maintain the NAAQS. The following analysis provides Carmeuse's evaluation of technically feasible reduction strategies and the final RACT selection.

3.1. TECHNICAL FEASIBILITY AND AVAILABILITY

For the purposes of reducing Carmeuse's contribution to modeled ambient air impacts greater than the NAAQS, (as the facility was not determined to contribute to monitored exceedances) Carmeuse analyzed the potential use of various reduction strategies for the kilns. The following resources are typically consulted when identifying potential strategies:

- EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;
- Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies;
- Previous engineering experience with similar applications;
- Information provided by air pollution control equipment vendors with significant market share in the industry; and/or
- Review of literature from industrial technical or trade organizations.

Entries from the RBLC and permit reviews are included in Appendix A. Table 3-1 provides a list of the reduction strategies evaluated as potential RACT for the River Rouge Facility lime kilns.

[2] Letter from G. Vinson Hellwig (DEQ) to Ms. Stacey Rader (Carmeuse) dated December 6, 2013.

Table 3-1. Reduction Strategies for SO_2

SO_2 Control Technologies
Inherent Dry Scrubbing
Wet Scrubbing
Semi-Wet Scrubbing
Dry Sorbent Injection
Lower Sulfur Fuels
Increased Oxygen Levels
Improved Dispersion

3.1.1. Inherent Dry Scrubbing

Lime and limestone present in the process act as a natural scrubber for SO_2. This inherent dry scrubbing is an integral part of the process system and is currently in use. This is the base case and will not be considered further as part of this analysis.

3.1.2. Wet Scrubbing

Wet SO_2 scrubbers operate by flowing the flue gas upward through a large reactor vessel that has an alkaline reagent (that is, limestone, lime slurry, or other alkaline material) flowing down from the top. The scrubber mixes the flue gas and alkaline reagent, using a series of spray nozzles to distribute the reagent across the scrubber vessel. The calcium in the reagent reacts with the SO_2 in the flue gas to form calcium sulfite ($CaSO_3$) and/or calcium sulfate ($CaSO_4$) that is removed from the scrubber with the sludge and is disposed. Most wet scrubbing systems utilize forced oxidation to assure that only $CaSO_4$ sludge is produced. Wet scrubbing with lime is a technically feasible option for controlling SO_2 emissions from a lime kiln.

3.1.3. Semi-Wet Scrubbing

Spray dryer systems operate by injecting a moist sorbent into the scrubber. As the hot flue gas mixes with the sorbent, water is evaporated. This process is sometimes referred to as semi-wet scrubbing. The sorbent is normally lime or calcium hydroxide. The surfaces that are exposed to the solid sorbent react with SO_2. Semi-wet scrubbing with lime is a technically feasible option for controlling SO_2 emissions from a lime kiln.

3.1.4. Dry Sorbent Injection

In a dry sorbent injection (DSI) system, sodium or calcium based sorbent is injected into the gas stream to react with SO_2 to form Na_2SO_4 or $CaSO_3$ which is then collected in the kiln's baghouse. Sorbent injection is an available and proven technology for SO_2 control on boilers. However, sorbent injection is not included in the RBLC database for lime kilns and Carmeuse has been unable to identify a demonstrated application of this technology on existing lime kiln operations for SO_2 reduction. The temperature profiles in lime kiln exhaust streams are different than those of a boiler; as such, the absorption processes upon which this technology is dependent could be less efficient, resulting in decreased SO_2 removal efficiencies. Consequently, there is no data available with which to establish an expected SO_2 control efficiency and corresponding RACT emission limit. Furthermore, a recent EPA supported study for cost development methodology for a DSI system indicated a target removal rate of 70% when a baghouse system is used for boilers.[3] If levels of control targeted for boilers could be achieved in a kiln, this level is still not appreciably different than the typical 60-80% reduction in SO_2 achieved through inherent dry scrubbing for the River Rouge Facility kilns. Therefore, claiming any additional control from the use of DSI in addition to the inherent dry scrubbing within a straight rotary kiln is speculative and would likely require pilot studies to assess feasibility and potential effectiveness. For all these reasons, DSI it is not a technically feasible option.

3.1.5. Lower Sulfur Fuels

One of the main sources of SO_2 emissions from a lime kiln is sulfur in the kiln's fuel. Decreasing the amount of sulfur in the fuel could potentially decrease SO_2 emissions; therefore, this is a technically feasible option.

3.1.6. Increased Oxygen Levels

Increasing oxygen levels at the burner causes a reaction between oxygen (O_2) and SO_2 to form sulfur trioxide (SO_3) which, in turn, reacts with lime to form $CaSO_4$. The $CaSO_4$ is then incorporated into the lime product, which decreases product quality in relation to customer demand. As such, this technology is not technically feasible for use in a lime kiln and will not be discussed further.

3.1.7. Improved Dispersion

As previously stated, the River Rouge facility has not been demonstrated to contribute to any monitored NAAQS exceedances. Rather, DEQ's request is based on a "hotspot" dispersion modeling analysis, which showed based on computer model simulations that, under a combination of worst-case meteorological conditions and worst-case emissions from the River Rouge Facility, concentrations in excess of the NAAQS may be possible. If Carmeuse can refine the release characteristics for the kiln stacks to improve dispersion and reduce the ambient impacts in DEQ's analysis to below the NAAQS, then use of add-on control technologies or other reduction strategies is not required, This was a reduction option specifically identified in MDEQ's RACT analysis submittal request and is a technically feasible option.

3.2. COST EVALUATION AND OTHER IMPACTS

As noted above, reducing Carmeuse's contribution to modeled ambient air impacts greater than the NAAQS (not actual monitored exceedances) is achievable through emissions reductions or using improved dispersion. Therefore, the cost evaluation for this RACT analysis is based on the current dollar value on an annualized basis in order to allow for accurate comparison of each reduction strategy. Given the brief time available to prepare the analysis, some site specific factors contributing to control costs have not been factored in (e.g., potentially severe constraints on available space at this facility for new equipment). Therefore, actual cost could potentially be higher than presented in this analysis.

3.2.1. Wet Scrubbing

There are multimedia implications to the use of wet scrubbing. The sludge from wet scrubbing creates a solid waste handling and disposal problem. This sludge must be handled in a manner that does not result in groundwater contamination. Also, the sludge disposal area needs to be permanently set aside from future

[3] Sargent & Lindy LLC. *IPM Model – Revisions to Cost and Performance for APC Technologies: Dry Sorbent Injection Cost Development Methodology.* August 2010. 14 Jan. 2014. http://www.epa.gov.

surface uses since the disposed material cannot bear any weight from such uses as buildings or cultivated agriculture.

Disadvantages associated with wet scrubbing with lime also include the creation of a visible wet stack with a visible plume of water droplets, generation of particulate matter by the scrubbing process causing elevated opacity, increased water consumption, and wastewater and sludge disposal issues. Wet scrubber systems for both kilns have an annualized cost of $6,000,000 per year, not including the cost of building and maintaining a system to handle the large amount of wastewater sludge generated by the scrubber or the cost of installing new kilns stacks after the wet scrubbers.[4] Furthermore, space limitations specific to the River Rouge Facility could further increase installation costs and costs associated with lost revenue for temporary kiln shutdowns needed to allow for scrubber installation. Note that the costs may be reduced slightly by routing the kilns to a single control device, but such a control scenario would greatly reduce operational flexibility due to the reliance of all production on a single control device. Cost calculations for this control technology are included in Appendix B.

3.2.2. Semi-Wet Scrubbing

The process of semi-wet scrubbing forms a dry waste product that is collected in a baghouse. The performance of the semi-wet system is sensitive to operating conditions and its performance cannot be assured without additional temperature control devices. Environmental disadvantages of this system include the production of dry waste, which requires landfill disposal and water usage, in place of the lime kiln dust (LKD), a saleable product in the current kiln design.

A cost estimate was prepared to evaluate the economic feasibility of a semi-wet scrubber for the proposed kiln. Semi-wet scrubber system for both kilns have an annualized cost of $4,700,000 per year, not including the increased cost of handling and processing the waste collected in the baghouse or the value of losing saleable LKD product. Furthermore, space limitations specific to the River Rouge Facility could further increase installation costs and costs associated with lost revenue for kiln shutdowns needed to allow for scrubber installation. Combining exhaust streams for control by a single control device will limit operational flexibility due to the reliance on a single control device to operate both kilns and is therefore not considered in this analysis. Cost calculations for this control technology are included in Appendix B.

3.2.3. Lower Sulfur Fuels

Using 2010 to 2013 data, the average sulfur content of coal used at the River Rouge facility is 1.0 % as received. Due to increasing demand for lower sulfur coal, it is becoming more difficult to guarantee availability of coal with a lower sulfur content than that currently used. Carmeuse's plant in Gary, Indiana (Buffington Plant), currently uses at coal with 0.65 % sulfur. However, this is an increase from previous agreements with the supplier to provide 0.5 % sulfur coal, and was subjected to a recent increase in price. Furthermore, low sulfur coal is often tied to higher ash contents or other downgrades in coal quality, which could increase the number of kiln shutdowns needed to remove ash rings from the kiln. The limited availability, unpredictable cost, and potential coal quality concerns associated with making a modest reduction from 1.0 % low sulfur coal to an even lower 0.65 % indicate that use of lower sulfur coal is not a reasonably available reduction strategy and will not be further evaluated as part of this RACT analysis.

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[4] The current kiln exhausts consist of monovents situated atop the baghouses. Because the wet scrubbers would be located after the baghouse, new kiln stacks would be needed.

3.2.4. Improved Dispersion

The estimated cost of installing a new stack to improve dispersion characteristics and meet the NAAQS is $750,000/yr. Cost calculations for this reduction strategy are included in Appendix B. This cost evaluation is based on installation of a stack that would reduce the ambient impacts of DEQ's hotspot modeling analysis to levels below the NAAQS without the use of add-on controls or other reduction technologies.

3.3. ESTABLISH RACT

In order to accurately compare the costs for each reduction strategy, the cost of each option on a dollars per year basis is provided in the table below.

Table 3-2. Annual Cost Comparison

SO_2 Reduction Strategy	Cost ($/yr)
Wet Scrubbing	6,000,000
Semi-Wet Scrubbing	4,700,000
Improved Dispersion	750,000

In addition to higher annual cost, use of a wet scrubber will result in adverse environmental impacts, including increased opacity, generation of particulate matter, generation of sludge requiring disposal and treatment while use of the semi-wet scrubber could result in uneven performance and the generation of dry waste in place of the currently saleable LKD product. Furthermore, actual cost for the wet scrubbing systems would be higher than those presented after incorporating costs for new stacks and construction and operation of sludge processing systems. Similarly, actual costs for the semi-wet scrubbing systems would be higher than those presented after accounting for increased cost of solid waste disposal and the revenue lost from the previously saleable LKD product. Each scrubbing option could also result in additional costs or feasibility concerns due to the limited footprint available for installation of additional controls at the River Rouge Facility.

Taking all of these factor into consideration and given that the River Rouge facility is not contributing to any monitored SO_2 NAAQS violations, we propose that increased dispersion be considered RACT. Furthermore, we specifically request that any RACT requirement established as a result of this modeled hotspot include flexibility for Carmeuse to use alternative means to achieve a similar or better result than solely relying on increased dispersion should Carmeuse deem an alternative necessary.

APPENDIX A: RBLC AND PERMITS REVIEW

EPA RBLC Database and Permits Review - Kiln SO_2 NSR Projects 2004 to Current

Year	Company	Facility	RBLC	Product	Fuel	Design	Project Description	Production Rate	Add-On Controls	Continuous Monitoring	Normalized SO_2 (lb/t lime produced)	SO_2 BACT	SO_2 Limit / Emission Factor	Sulfuric Acid Mist Limit / Emission Factor
2012	Graymont	Pleasant Gap	PA-0283 (draft)	CaO	natural gas	vertical	Kiln 8	660 tpd lime	baghouse	SO_2 NO_x and CO CEMS	0.8	(a) use of a vertical kiln and (b) good operating practices within the kiln	23.0 lb/hr 30 day rolling avg 500 ppmvd	
2010	Mississippi Lime	Prairie du Rocher	IL	CaO	coal coke	preheater	New preheater rotary kilns (2)	2400 tpd lime for two kilns	Baghouse	SO_2 NO_x and CO CEMS	0.65	Inherent dry scrubbing	0.645 bs/ton lime daily 24-hr avg 32.3 lb/hr 3-hr avg each 141.5 tpy each	
2010	Vulcan	Monteno	IL	MgO	coal pet coke	preheater	Modification to install spray dryer absorber shorten the length of the kiln and install a pre-heater tower - facility has been idled	600 tpd lime	spray dryer absorber and Baghouse	SO_2 NO_x and CO CEMS	4.3	spray dryer absorber and Baghouse	2.2 lb/t stone feed 3-hr avg 2.0 lb/t stone feed 30-day avg or such lower limits (as low as 1.8 and 1.5 lb/t stone feed respectively) as may be set based on actual k ln emissions 119 lb/hr 3-hr avg 119 lb/hr 24-hr avg 473.0 tpy	
2010	Synergy Management	White County	IN	MgO	coal pet coke	preheater	New preheater rotary kilns (2)	900 tpd lime each	Baghouse	none	2.00	proper kiln design and operation (inherent scrubbing)	2.0 lb/ton l me 3-hr avg 6 lb/mmbtu 75.0 lb/hr 3-hr avg	
2009	Graymont	Superior	WI-0250	CaO	coal pet coke	preheater	Modification to Kiln 5	650 tpd lime	Baghouse	SO_2 NO_x and CO CEMS	1.2	use of a preheater type rotary kiln with a high temperature / membrane fabric filter Baghouse that ach eves at least 92% collection / retention of potential sulfur dioxide emissions and (b) a fuel sulfur content limit of 2.0% (by weight)	0.62 lbs/tsf (stone) 24-hr rolling avg 33.7 lbs/hr 3-hr rolling avg	1.5000 lb/hr sulfuric acid mist
2008	Martin Marietta Magnesia Specialties	Sandusky	OH-0321	MgO	coal pet coke NG	preheater	New rotary kiln - Kiln 7	900 tpd lime 37.5 tph lime	Baghouse		1.70	no add-on controls found cost effective - Fuel sulfur content limit back calculated	1.7 lbs/t lime 279.23 tpy 12-month rolling	
2007	Mississippi Lime	Verona	KY	CaO	coal pet coke	preheater CFB	New rotary kilns (2)	840 tpd lime each	Baghouse		0.4	CFB fuel sulfur lower than tested value	12.25 lb/hr 3-hr avg 0.35 lb/t lime 30-day avg	
2007	Graymont	Pleasant Gap	Minor NSR	CaO		preheater	Modification to permit for new preheater rotary k ln - Kiln 7		Baghouse and semi wet caustic scrubber					
2006	Graymont	Superior	WI-0233	CaO	coal pet coke	preheater	New kiln - Kiln 5	650 tpd lime	Baghouse		1.24	2% sulfur in fuel - assumes 92% CE from inherent scrubbing of gas in Baghouse	0.62 lb/t stone feed 24-hr avg 33.7 lb/hr 3-hr avg	1.5 lb/hr sulfuric acid mist Acid gas HAPs controlled by reaction with lime in kiln preheater and Baghouse (92% CE)
2006	Graymont	Pilot Peak Plant	NV-0040	CaO	coal	preheater	Modification to Kiln 1 (increase fuel S content)	600 tpd lime	Baghouse	SO_2 CEMS	0.6	3% sulfur	14 lb/hr 3-hr avg	
2006	Graymont	Pilot Peak Plant	NV-0040	CaO	coal	preheater	Modification to Kiln 2 (increase fuel S content)	800 tpd lime	Baghouse	SO_2 CEMS	0.6	3% sulfur	21 lb/hr 3-hr avg	
2006	Graymont	Pilot Peak Plant	NV-0040	CaO	coal	preheater	Modification to Kiln 3 (increase fuel S content)	1200 tpd lime	Baghouse	SO_2 CEMS	0.7	3% sulfur	33.6 lb/hr 3-hr avg	
2006	Dakota Coal	Frannie Plant		CaO	coal pet coke	rotary	Modification to kiln (increase SO_2 limit from 9 to 12 lb/hr and related new coal mill installation)	500 tpd lime	Baghouse	NO_x CEMS	0.58	inherent scrubbing	12 lb/hr 52.6 tpy	

EPA RBLC Database and Permits Review - Kiln SO_2 NSR Projects 2004 to Current

Year	Company	Facility	RBLC	Product	Fuel	Design	Project Description	Production Rate	Add-On Controls	Continuous Monitoring	Normalized SO_2 (lb/t lime produced)	SO_2 BACT	SO_2 Limit / Emission Factor	Sulfuric Acid Mist Limit / Emission Factor
2005	**Chemical Lime**	**O'Neal Plant**	AL-0220	CaO	coal	preheater	New preheater rotary kiln and modification to existing kiln (same limits for both)	1500 tpd lime		SO_2 CEMS	1.4	not specified	2.05 lb/t lime 24-hr avg 1.4 lb/t 12-month avg 128.12 lb/hr 3-hr avg 383.25 tpy 12-month rolling	
2005	**Arkansas Lime**	**Batesville**	AR-0082	CaO	coal coke NG	preheater	New rotary preheater kiln - Kiln 3	687 tpd lime	Baghouse	O_2 Monitor	1.13	dry scrubb ng by lime prod. 92%CE 4%S daily avg 3%S 30-day rolling avg	44.8 lb/hr 141.6 tpy	
2005	**Western Lime**	**Port Inland**	MI-0383	CaO	#2 FO propane coal pet coke	preheater	New rotary preheater kiln - Kiln 1	870 tpd	Baghouse	NO_x CEMS	1.5	2.5% sulfur in fuel monthly average	60.2 lb/hr monthly basis 242 tpy 12-month rolling (hourly limit was based upon 0.83 pounds per ton of stone feed)	
2004	**Graymont**	**Pleasant Gap**	PA-0241	CaO	coal pet coke	preheater	New preheater kiln - Kiln 6	1200 tpd	Baghouse	SO_2 CEMS	2.61	annual average fuel sulfur content of 2%	305 lb/hr 3-hr block avg 571 tpy 12-month rolling 500 ppm 1-hr avg	
2004	**Graymont**	**Pleasant Gap**	PA-0241	CaO	coal pet coke	rotary	New rotary kiln - Kiln 7	1050 tpd	Baghouse and caustic scrubber meeting 93%CE	SO_2 CEMS	1.11	scrubber and FO limit of 0.5%S annual average fuel sulfur content of 3%	92.83 lb/hr 3-hr block avg 213 tpy 12-month rolling 500 ppm 1-hr avg	

APPENDIX B: COST ANALYSES

Wet Scrubber Costs			Page (1 of 2)
Direct Costs			
Purchased Equipment Costs			
	Wet Scrubber Unit		$3,190,000
	Instrumentation (10% of EC)		$319,000
	Sales Tax (3% of EC)		$95,700
	Freight (5% of EC)		$159,500
		Subtotal, Purchased Equipment Cost (PEC)	$3,764,200
Direct Installation Costs (Handling and Erection included in wet scrubber cost)			
	Foundation (6% of PEC)		$225,852
	Supports (6% of PEC)		$225,852
	Electrical (1% of PEC)		$37,642
	Piping (30% of PEC)		$1,129,260
	Insulation for Ductwork (1% of PEC)		$37,642
	Painting (1% of PEC)		$37,642
		Subtotal, Direct Installation Cost	$1,693,890
Site Preparation			Not Quantified
Buildings			Not Quantified
Sludge Processing System			Not Quantified
Engineering and Design Consideration for Limited Available Footprint			Not Quantified
New Stack[1]			Not Quantified
		Total Direct Cost	$5,458,090
Indirect Costs			
	Engineering (8% of PEC)		$301,136
	Construction Fee (3% of PEC)		$112,926
	Construction and Field Expense (10% of PEC)		$376,420
	Start-up (1% of PEC)		$37,642
	Performance Test (1% of PEC)		$37,642
		Total Indirect Cost	$865,766
	Total Direct and Indirect Costs (TDIC)		$6,323,856
	Contingency (3% of TDIC) per CCM		$189,716
Post Scrubber Baghouse			
		Total Direct and Indirect Cost	$10,000,000
	Total Capital Investment (TCI)		$16,513,572

[1] The current stack for each kiln is an extension of the baghouse vents. Since the wet scrubber must be installed after the baghouse, new stacks will be required.

Wet Scrubber Costs

Direct Annual Costs			
Hours per Year (365 days per year, 24 hours per day)			8,760
Operating Labor			
	Operator (0.5 hr/shift, 3 shifts/day, 365 d/yr, $26.15/hr)		$14,317
	Supervisor (15% of operator)		$2,148
		Subtotal, Operating Labor	$16,465
Maintenance			
	Labor (0.5 hr/shift, 3 shifts/day, 365 d/yr, $19.34/hr)		$10,589
	Material (100% of maintenance labor)		$10,589
		Subtotal, Maintenance	$21,177
Variable O & M			
	Electricity		
	Pump (kW)		489.41
	Cost ($/kW-hr)		$0.0785
		Subtotal, Electricity	$336,549
	Limestone Slurry		
	Amount Required (ton/yr)		912
	Cost ($/ton)		$89.00
		Subtotal, Lime	$81,198
	Sludge Processing		
		Subtotal, Sludge Processing	Not Quantified
		Subtotal, Variable O & M	$417,747
		Total Direct Annual Costs	**$455,389**
Indirect Annual Costs			
Overhead (60% of sum of operating, supervisor, maintenance labor & materials)			$71,304.20
Administrative (2% TCI)			$330,271
Property Tax (1% TCI)			$165,136
Insurance (1% TCI)			$165,136
Capital Recovery	(15 year life, 7 percent interest)		$1,813,101
		Total Indirect Annual Cost	**$2,544,948**
	Total Annualized Cost (per scrubber)		**$3,000,338**
	Total Annualized Cost (Kiln 1 and Kiln 2 scrubbers)		**$6,000,675**
	Kiln 1		
	Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)		552
	Pollutant Removed (tons SO_2/yr) assuming 90% removal		497
	Cost Per Ton of Pollutant Removed assuming 90% removal		$6,041
	Kiln 2		
	Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)		583
	Pollutant Removed (tons SO_2/yr) assuming 90% removal		524
	Cost Per Ton of Pollutant Removed assuming 90% removal		$5,723

Semi-Wet Scrubber Costs			
			Page (1 of 2)
Direct Costs			
	Purchased Equipment Costs		
		Supply Price	$6,056,778
	Direct Installation Costs		
		Installation Price	$3,579,005
	Site Preparation		Not Quantified
	Buildings		Not Quantified
	Engineering and Design Consideration for Limited Available Footprint		Not Quantified
	Total Capital Investment (TCI)		**$9,635,782**

Semi-Wet Scrubber Costs		Page (2 of 2)
Direct Annual Costs		
Hours per Year (365 days per year, 24 hours per day)		8,760
Operating Labor		
Operator (0.5 hr/shift, 3 shifts/day, 365 d/yr, $26.15/hr)		$14,317
Supervisor (15% of operator)		$2,148
	Subtotal, Operating Labor	$16,465
Maintenance		
Labor (0.5 hr/shift, 3 shifts/day, 365 d/yr, $19.34/hr)		$10,589
Material (100% of maintenance labor)		$10,589
	Subtotal, Maintenance	$21,177
Variable O & M		
Electricity		
Pump (kW)		489.41
Cost ($/kW-hr)		$0.0785
	Subtotal, Electricity	$336,549
Hydrated Lime (Reagent)		
Amount Required (ton/yr)		1,276
Cost ($/ton)		$250.00
	Subtotal, Lime	$319,056
Solid Waste		
Solid Waste Processing		Not Quantified
Losses of Saleable Lime Kiln Dust (LKD)		Not Quantified
	Subtotal, Solid Waste	Not Quantified
	Subtotal, Variable O & M	$655,605
	Total Direct Annual Costs	**$693,247**
Indirect Annual Costs		
Overhead (60% of sum of operating, supervisor, maintenance labor & materials)		$214,019
Administrative (2% TCI)		$192,716
Property Tax (1% TCI)		$96,358
Insurance (1% TCI)		$96,358
Capital Recovery (15 year life, 7 percent interest)		$1,057,957
	Total Indirect Annual Cost	**$1,657,407**
Total Annualized Cost (per scrubber)		**$2,350,653**
Total Annualized Cost (Kiln 1 and Kiln 2 scrubbers)		**$4,701,307**
Kiln 1		
Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)		**552**
Pollutant Removed (tons SO_2/yr) assuming 90% removal		**497**
Cost Per Ton of Pollutant Removed assuming 90% removal		**$4,733**
Kiln 2		
Pollutant Emission Rate Prior to Scrubber (tons SO_2/yr)		**583**
Pollutant Removed (tons SO_2/yr) assuming 90% removal		**524**
Cost Per Ton of Pollutant Removed assuming 90% removal		**$4,484**

Improved Dispersion - New Stack Costs		
Direct and Indirect Costs		
	Total Capital Investment (TCI)	**$5,600,000**
Direct Annual Costs		
Operating Labor and Supervision		Negligible
Maintenance Labor and Materials		Negligible
Electricity (assume negligible increase in pressure drop for new stack)		Negligible
	Total Direct Annual Costs	**$0**
Indirect Annual Costs		
General and Administrative (2% TCI)		$112,000
Property Tax (1% TCI)		$56,000
Insurance (1% TCI)		$56,000
Capital Recovery (20 year life, 7 percent interest)		$528,600
	Total Indirect Annual Cost	**$752,600**
Total Annualized Cost		**$752,600**

UNITED STATES STEEL CORPORATION
GREAT LAKES WORKS
SO_2 REASONABLY ACHIEVABLE CONTROL TECHNOLOGY EVALUATION

Prepared for:

United States Steel Corporation
Great Lakes Works

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Project No. 151439
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Table of Contents

List of Tables

List of Figures

List of Appendices

1.0 Executive Summary

The Reasonable Available Control Technology (RACT) analysis included an evaluation of available SO_2 controls for the following emission units at United States Steel Corporation (USS) Great Lakes Works (GLW):

- Hot Mill Reheat Ovens,
- Boiler Houses 1 and 2, and
- Related Flares

There are five (5) furnaces associated with the Hot Mill Reheat Ovens. The Hot Mill is located between Zug Island and the main USS GLW plant in the City of River Rouge. Each boiler house contains five (5) boilers and an associated flare. Boiler Houses 1 and 2 and associated flares are all located on Zug Island at the primary iron producing facility.

Add-on SO_2 controls including Dry Sorbent Injection (DSI), Spray Dryer Absorber (SDA), and wet scrubbers were all evaluated as part of the RACT analysis. Each of these add-on control devices were considered theoretically feasible. Due to the challenges associated with retrofitting a stand-alone control device at an existing source, it was concluded that a more detailed engineering analysis would be needed before each of these controls could be considered technically feasible. The cost effectiveness of each of these technologies was cost prohibitive, and was therefore rejected as RACT.

Alternative SO_2 controls including fuel switching, fuel blending, and increased dispersion were all evaluated for the RACT analysis. Each alternative control was considered technically feasible. Increased dispersion was determined to be cost prohibitive and rejected as RACT. Fuel switching and fuel blending were both considered technically feasible for Boiler House 1 and 2 and the Hot Mill Reheat Ovens. However, fuel switching was rejected because it was not considered economically feasible and would result in significant collateral impacts that must be considered, and are generally converse to implementation of RACT. Our analysis indicates that fuel switching would result in a Prevention of Significant Deterioration (PSD) significant emission increase (SER) of other pollutants at the USS GLW plant, and would not result in a "real" reduction in SO_2 emissions; and would increase emissions of other pollutants in the area. The fuel switching analysis evaluated substituting natural gas for coke oven gas (COG). If COG is not used in the Boiler Houses or Hot Strip Mill, it must be flared at the adjacent metallurgical coke plant. This does not result in any reduction in SO_2 emissions and could actually increase overall SO_2 emissions, as well as other pollutants, in the area since additional natural gas would be burned to substitute for the loss in COG, while the COG is being flared at the coke plant simultaneously. The additional COG flaring could significantly increase emissions at the adjacent coke plant for pollutants such as nitrogen oxides (NOx), thereby resulting in collateral impacts affecting ambient air quality, including possibly preventing the area from attaining the National Ambient Air Quality Standards (NAAQS) with the 1-hour NOx standard.

CB&I concluded that the most reasonable SO_2 control that was both technically and economically feasible is fuel blending. Fuel blending involves using various fuel blends to achieve an overall lower fuel sulfur level. During calendar year 2013, the average SO_2 emission rate for USS GLW's emission units subject to the RACT analysis was 0.32 lb/MMBtu. CB&I recommends that USS GLW propose an emission rate of 0.40 lb/MMBtu on an annual average basis for the combined emission rate of Boiler House 1, Boiler House 2, Flares, and Hot Strip Mill Furnaces. This value represents the emission rate obtained by USS GLW during the 2013 calendar year with a 25% increase to account for variability. Additionally, this emissions level results in a 15% reduction of SO_2 emissions from years that were used to designate the area as nonattainment and subsequently modeled by MDEQ and satisfies the definition of RACT. It should be noted that a short-term average would require a considerably higher emission rate to account for fuel blending fluctuations. Further, in the event operations are interrupted due to process upsets and temporary fuel loss situations (e.g. loss of BFG), an alternate SO_2 emission limit for this operating scenario would need to be established.

2.0 Introduction

On June 11, 2011 the Michigan Department of Environmental Quality (MDEQ) submitted its recommended designations to U. S. Environmental Protection Agency (USEPA) for the new 1-hour SO_2 National Ambient Air Quality Standards (NAAQS). This included recommending that a sub-boundary in Wayne County, south of the Southwestern High School (SWHS), be designated non-attainment for this standard. As part of the SO_2 emission reduction strategy for this area, the MDEQ subsequently submitted a letter to USS GLW on December 6, 2013 requesting that a RACT analysis be completed for the hot mill reheat ovens, boiler houses 1 and 2, and related flares. In the RACT letter, MDEQ indicated that the SO_2 reduction strategies should include add-on control equipment, process modifications, fuel switching/cleaning, and increased dispersion. USS contracted with CB&I Environmental & Infrastructure, Inc. f/k/a Shaw Environmental, Inc. (CB&I) to provide assistance with conducting the RACT.

RACT is defined in the Code of Federal Regulations (40 CFR 51.100) as "devices, systems, process modifications, or other apparatus or techniques that are reasonably available taking into account: (1) The necessity of imposing such controls in order to attain and maintain a national ambient air quality standard; (2) The social, environmental, and economic impact of such controls; and (3) Alternative means of providing for attainment and maintenance of such standard. (This provision defines RACT for the purposes of §51.341(b) only.)" Specific Federal or Michigan guidance on conducting a RACT analysis was not available for SO_2; therefore, a "Top-Down" approach similar to a Best Available Control Technology (BACT) analysis was selected. The only exception to this approach is that RACT requires sources to adopt controls that are reasonably available and thus may not be the most stringent controls that have been adopted by other similar sources such as the best available control as required in a BACT analysis. MDEQ has requested that USS evaluate enhanced dispersion in the RACT analysis; therefore, enhanced dispersion from each of the emission units was evaluated as a form of control that reduces the ground level impact of SO_2 emissions.

A source of control technology information is the RACT/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database. The RBLC is an EPA-sponsored database that lists previously EPA-approved RACT/BACT/LAER determinations. CB&I consulted this database as the first step in developing a list of the most recent RACT/BACT/LAER decisions for similar sources, including blast furnace operations and boilers of various size ranges. The results of the RBLC search are summarized in Appendix A of this analysis.

The RACT analysis includes an evaluation of available add-on SO_2 controls as well as alternative forms of emission controls for each of the requested emission units by MDEQ. A technical feasibility and cost analysis evaluation was performed to determine the suitability of each of the identified SO_2 control options as RACT.

3.0 Basis of RACT Analysis Request by MDEQ

The USEPA revised the primary NAAQS for SO_2 on June 2, 2010. The USEPA replaced the 24-hour and annual SO_2 standards, set in 1971, with a new short-term standard based on the 3-year average of the 99th percentile of the yearly distribution of 1-hour daily maximum SO_2 concentration. The new level was set at 75 parts per billion (ppb). In accordance with Section 107 of the federal Clean Air Act (CAA), within one year of a new or revised NAAQS, states were to submit designation recommendations to the USEPA. The recommendations were to include the boundaries for areas to be designated as nonattainment. The USEPA issued a guidance memorandum on March 24, 2011, to direct states on the SO_2 designation process and time line.

On June 11, 2011 the MDEQ submitted its recommended designations to USEPA for the new 1-hour SO_2 NAAQS. The MDEQ recommended a sub-county boundary in Wayne County, Michigan as nonattainment and the remainder of Wayne County as unclassifiable. As part of the SO_2 emission reduction strategy, the MDEQ subsequently submitted a RACT request to USS GLW on December 6, 2013. The request stated that the RACT was limited to the following emission units at USS GLW:

- Hot Mill Reheat Ovens,
- Boiler Houses 1 and 2, and
- Related Flares

In the RACT letter, MDEQ indicated that the SO_2 reduction strategies should include add-on control equipment, process modifications, fuel switching/cleaning, and increased dispersion. Each analysis, with the exclusion of dispersion modeling, is to include an estimation in reduced annual SO_2 tons and an associated cost evaluation in dollars per ton reduced.

4.0 RACT Analysis Approach for SO_2

As previously discussed, there is no specific guidance on completing a RACT analysis for SO_2. Consequently, the "Top-Down" BACT approach was used as a guidance tool to complete the RACT analysis for USS. The "Top Down" approach starts with the top technology that has been applied to similar emissions units. To utilize the "Top-Down" approach, commercially available control options for each applicable pollutant, which in this case includes SO_2 only, are identified. Technically infeasible alternatives are then eliminated, and the remaining control options are analyzed and ranked according to control effectiveness. The top control technology is either accepted or rejected based on technical or economic infeasibility. If the top control technology is rejected, the next most stringent control technology is either accepted or rejected. The top-down approach is continued until a control technology, which is found to be both technically and economically feasible, is accepted. To select a RACT option, the following items are evaluated: cost effectiveness, environmental effects, energy impacts, and site-specific factors. The control technology selected provides a reasonable level of control without causing adverse economic, energy, or environmental impacts. Generally, the cost effectiveness parameter is stated as either total or incremental annualized dollar cost per ton of pollutant abated. The following steps provide a general outline of the "Top-Down" process that was generally implemented for this RACT analysis. In practice, each step may not apply, and the steps may be overlapped, combined, or undertaken in a different order depending on the specific emission units and considerations involved.

Step 1 – Identify All Control Technologies

The first step in this RACT approach is to define the spectrum of process and/or add-on control alternatives that will be considered potentially applicable to the emissions unit.

Step 2 – Eliminate Technically Infeasible Options

The second step in this RACT approach is to evaluate the technical feasibility of the alternatives identified in Step 1 and to reject those which are technically infeasible based on engineering evaluation or on chemical or physical principles. Criteria that may be considered in determining technical feasibility include previous commercial state demonstrations, precedents based on previous permits, technology transfer from similar sources, and limitations imposed by existing equipment design of the emissions unit under review.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

In Step 3 the alternatives are ranked into a control hierarchy from most to least stringent. To the extent practical, this involves an assessment and documentation of the emissions control level or emissions limit achievable with each technically feasible alternative, considering the specific operating constraints of the emissions units undergoing review. Generally accepted control efficiencies or ranges of control efficiencies may be presented where detailed information for the specific emissions unit is not available.

Step 4 – Evaluate Most Effective Control Options and Document Results

If the top-ranked technically feasible control is not selected, Step 4 is to evaluate and document the cost, economic, environmental, and energy impacts of the top or most stringent technique. To reject the top alternative, it must be demonstrated that this control alternative is not the most reasonable control based on the results of the impacts analysis. If a control technology is determined to be infeasible based on high cost effectiveness, or to cause adverse economic, energy or environmental impacts (including toxic pollutant impacts) that would outweigh the benefits of the additional emissions reduction as compared to a lower ranked control, then the control technology is rejected and the next most stringent control alternative is considered in turn.

Step 5 – Select RACT

The proposed RACT is the option with the most reasonable control effectiveness that was not eliminated based on consideration of cost, economic, energy or environmental impacts.

4.1 Cost Determination Methodology

Economic analyses of RACT alternatives were performed to compare capital and annual costs in terms of cost effectiveness (i.e., dollars per ton of pollutant removed). Capital costs include the initial cost of components intrinsic to the complete control system (spray dryer absorber (SDA), for example, includes spray dryer tower, baghouse, stack, induced draft fan, support frame, ductwork, lime silo, piping, atomizer equipment, instrumentation, monitoring equipment, and installation costs). Annual operating costs consist of the financial requirements to operate the control system on an annual basis and include overhead, maintenance, outages, labor, raw materials, and utilities.

4.1.1 Capital Costs

The capital cost estimating technique used in this analysis is based on a combination of cost data from the Coal Utility Environmental Cost (CUECost) model, the factored cost estimating technique presented in the latest USEPA guidance manual for estimating control technology costs Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual, and vendor quotes. Capital cost estimates generated from CUECost were inserted into the factored cost estimate format presented in the OAQPS manual. Line item costs included in the OAQPS Control Cost Manual estimating method that were not provided in the CUECost workbook were factored from Total Capital Cost using the appropriate Control Cost Manual factor. Due to variations in the output format of CUECost, merging of the cost estimating data into OAQPS Control Cost Manual format were each slightly different for the wet scrubber, SDA, and dry sorbent injection (DSI) analysis, depending on the form that the estimates were reported in CUECost.

Purchased equipment costs represent the delivered cost of the control equipment, auxiliary equipment, and instrumentation. Auxiliary equipment consists of all structural, mechanical, and electrical components required for efficient operation of the device. These include such items as reagent storage and supply piping and distributed controls. Auxiliary equipment costs are taken as a straight percentage of the basic equipment cost, the percentage being based on the average requirements of typical systems, and their auxiliary equipment.

Direct installation costs consist of the direct expenditures for materials and labor for site preparation, foundations, structural steel, erection, piping, electrical, painting, and facilities. Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, and contingencies. Other indirect costs include equipment startup and performance testing, working capital, interest during construction, and allowance for funds during construction.

4.1.2 Annualized Costs

Annualized costs are comprised of direct and indirect operating costs. Direct costs include labor, maintenance, replacement parts, raw materials, utilities, and waste disposal. Indirect operating costs include plant overhead, taxes, insurance, general administration, and capital charges. Like the capital costs, the annualized costs were obtained from both CUECost and the OAQPS Manual. The estimates reported by CUECost were used as the primary source, and the USEPA factors were used to fill in remaining information.

Direct annual operating costs include the costs of labor, maintenance, materials, utilities, and replacement components necessary for the operation of the control equipment. Indirect costs consist of funds allocated for overhead, property taxes, and administration.

To determine the total annualized cost, it is necessary to calculate the capital recovery factor (CRF). The CRF is defined as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

Where i = the annual interest rate of the loan and

n = the equipment economic life (years).

The lifetime was assumed to be 15 years. The average interest rate was assumed to be 7 percent. CRF was therefore calculated to be 0.1098.

4.1.3 Cost Effectiveness

The cost-effectiveness of an available control technology is based on the annualized cost of the available control technology and its potential annual pollutant emission reduction which was based on 2010 emission estimates. Cost effectiveness is calculated by dividing the annualized cost of the available control technology by the theoretical tons of pollutant removed by that control technology each year. The basis for determining the percent reduction of a given technology was based on information contained in USEPA literature, and from engineering estimates. The cost effectiveness of each control system in units of dollars per ton of pollutant removed is described within respective sections of the RACT evaluations.

5.0 Dispersion Modeling Approach for SO_2

5.1 Dispersion Modeling Approach

In MDEQ's RACT request, one RACT option mentioned was increased dispersion of the emissions. Increased dispersion can be achieved by altering the parameters of the emission source exhaust. CB&I evaluated the increased dispersion option by altering the stack height of the emission sources in order to obtain a change in 1-hr SO_2 concentration, which is further discussed in Sections 6.1.5 and 7.1.5. USS supplied CB&I with a baseline modeling file that contained the source parameters and other modeling options as noted below. For SO_2, the 1-hour standard promulgated by USEPA in June 2010 is the 99^{th} percentile (equivalent to the 4^{th} highest daily maximum (H4H)) concentration averaged over three years.

5.1.1 Modeling Program

The increased dispersion evaluation was conducted using the latest version (13350) of AERMOD since this is the model used by MDEQ; as recommended by USEPA. The AERMOD model is an USEPA-approved model that was introduced to incorporate air dispersion based on planetary boundary layer turbulence structure and scaling concepts, including treatment of both surface and elevated sources, and both simple and complex terrain.

5.1.2 Urban or Rural Dispersion Option

According to the modeling input files provided by USS, the land use surrounding the area is classified as rural. Therefore, the rural option was selected in the modeling analysis. Although the rural option was selected, stacks less than 150 feet high were modeled using the urban option as based on the MDEQ model.

5.1.3 Land Use and Terrain

The modeling input file obtained from USS included terrain elevations for the facility sources as well as the modeled receptor.

5.1.4 Meteorology

AERMOD requires hourly surface meteorological data and twice-daily upper air data for calculating downwind concentrations. The data required for each simulation are:

- wind speed;
- wind direction;
- dry-bulb temperature;
- cloud cover;
- ceiling height;
- station pressure; and
- vertical profiles of temperature, pressure, and relative humidity.

The meteorological data used in the analysis consisted the last five years (2009-2013) of hourly surface observations taken at a nearby National Weather Service (NWS) Station in Detroit, Michigan (14822) along with concurrent twice-daily upper air data collected at the White Lake upper air station (72632). The preprocessed data was obtained from MDEQ.

5.1.5 Receptor

The dispersion modeling was conducted for one receptor. Due to time constraints, a receptor grid or hot spots were not considered in the analysis. The SO_2 monitor located at Southwestern High School (SWHS) was the only receptor evaluated in the increased dispersion modeling analysis. The SWHS monitor is located north of the USS GLW boiler house and northeast of the USS GLW reheat ovens at approximately 326356 meters Easting and 4685546 meters northing (in North American Datum 1983 (NAD83)).

5.1.6 Sources of Emissions

The increased dispersion option was evaluated for the following sources:

- Boiler House 1 (Boilers 1-5);
- Boiler House 2 (Boilers 1-5);
- Hot Strip Mill Reheat Ovens (Furnaces 1-5).

The associated flares were not evaluated in the increased dispersion option since these flares are existing open flares. It is not feasible to increase the stack height of these flares. Additionally, it is assumed that the emissions from the flares already are greatly dispersed due to the flame temperature and flame height. No other sources (on property or offsite) were considered in this analysis.

Emission source parameters modeled are included in Sections 6.1.6and 7.1.3.

6.0 Boiler House 1 and 2 RACT

6.1 Available Control Technologies

No specific add-on SO_2 controls were identified in the RBLC search for gas-fired boilers. Although coal fired boilers have higher uncontrolled SO_2 emissions than gas-fired boilers, the gas stream was considered somewhat comparable to the sulfur gas stream concentration of sulfurized coke oven gas (COG) that is utilized in the USS GLW boiler houses. Therefore, add-on SO_2 controls for coal fired boilers were evaluated as theoretically feasible control options. Generally, there are three types of add-on SO_2 controls applicable to a coal-fired boiler: dry (i.e., DSI), semi-dry (i.e., SDA), and wet (i.e., wet scrubber). Wet scrubbers and SDAs are collectively referred to as flue gas desulfurization (FGD) units. DSI may be used in boilers by dry injection of sorbents such as hydrated lime or Trona (sodium sesquicarbonate, a naturally occurring mineral mined in Wyoming) into the duct system; however, the level of control that is achievable is not comparable to FGD control systems. FGD controls applicable to boilers include wet scrubbing or SDA technology using reagents such as limestone, lime, quicklime, sodium bicarbonate, or magnesium oxide. Each of these add-on technologies have been considered for this RACT analysis.

Other types of alternative SO_2 controls were also considered for the boiler houses including fuel switching, fuel blending, and increased dispersion. Fuel switching involves substituting a lower sulfur fuel for higher sulfur fuels. At USS GLW, the highest sulfur fuel is COG followed by blast furnace gas (BFG) and natural gas. The typical sulfur values for the various fuels utilized in the boilers and furnaces at USS are provided in Table 6-1 below.

Table 6-1
Typical Sulfur Values of USS Gaseous Fuels

Gaseous Fuel	Sulfur Content (lb/MMBtu)
COG	1.43
BFG	0.08
Natural Gas	0.0006

Fuel blending, as defined in this analysis, includes using various fuel blends to achieve an overall fuel sulfur level thereby reducing the amount of SO_2 that is generated in the combustion process. Increased dispersion does not have the effect of decreasing overall SO_2 emissions, but can decrease the ground level impact of those emissions. These additional alternative controls have been included in this RACT analysis for Boilers House 1 and Boiler House 2. The pre-combustion scrubbing of BFG was not considered in this evaluation since no existing desulfurization controls were identified in the RBLC search, other than previous BACT determinations, which eliminated this option due to technically infeasibility[1].

A comparative ranking of available SO_2 control technologies must take into consideration multiple variables including fuel sulfur content, fuel sulfur variability, add-on control percent removal capability, and the resulting composite emission rate (lb/MMBtu) in addition to collateral impacts on other pollutants, energy impacts, and other environmental impacts. Any discussion of the relative effectiveness of add on SO_2 control also must take into account the level of uncontrolled SO_2 to be handled, which is highly dependent on the sulfur content of the fuel to be burned. Higher removal efficiencies tend to be more practical when there is a high concentration of SO_2 in the flue gas, and vice-versa. This is reflected in a comparison of the resulting emission rate in units of pounds of SO_2 per MMBtu of fuel burned. Table 6-2 below provides a summary of these technologies and their associated control rankings, which are based on coal-fired boilers.

Table 6-2
Control Ranking of SO_2 Technologies Identified for USS GLW Boilers

Control Technology	Typical Level of Control[2]	Typical Emission Level
Wet Scrubber	80-98%	Depends of fuel sulfur levels
SDA	70-90%	Depends of fuel sulfur levels
Fuel Switching	30-90%	Depends of fuel sulfur levels
Fuel Blending	20-60%	Depends of fuel sulfur levels
DSI	25-50%	Depends of fuel sulfur levels
Increased Dispersion	NA	NA

6.1.1 Summary of RACT/BACT/LAER Clearinghouse Information

CB&I conducted a search of the RBLC database for SO_2 controls for similar emissions units as those in the USS GLW RACT request by MDEQ. No add-on controls were identified in the RBLC search for gas-fired boilers in various size ranges. In addition, no add-on controls specific to the boilers were identified in the RBLC search for the steel and iron industry under process types 81.200, 81.300, and 81.400.

The most prevalent type of control identified in the RBLC for gaseous fuel for all industry boilers is to limit the sulfur content of the fuel purchased and/or utilizing a specific type of fuel (i.e. natural gas) with a low-sulfur content. Therefore, these types of controls were evaluated as part of this RACT analysis in addition to potential add-on controls. A summary of the RBLC search is provided in Appendix A

[1] Nucor - LA BACT determination for BFG SO2 control, RBLCID LA-0239.

[2] AP-42 Chapter 1.1, Bituminous and Subbituminous Coal Combustion, Table 1.1-1. Control level ranges for add-on controls only

6.1.2 Spray Dryer Absorber

In a SDA control system, the combustion process exhaust stream passes through the SDA upstream of a particulate matter (PM) control device (typically a fabric filter baghouse). An alkaline lime slurry is injected in the SDA using a rotary atomizer or fluid nozzles. The liquid sulfite/sulfate salts that form in the reaction of the alkaline slurry with SO_2 are dried by heat contained in the exhaust stream. Dry byproduct is collected in the bottom of the spray dryer and in the downstream baghouse. A simplified process flow diagram (PFD) is provided in Figure 6-1 below. The alkaline lime reagent may further react with SO_2 that passes through the filter cake in the baghouse. This additional reaction in the fabric filter can also aid in the removal of additional pollutants (i.e., sulfuric acid mist (H_2SO_4 mist), hydrochloric acid (HCl), hydrogen fluoride (HF), and mercury). The collected solids are either recycled back through the process or used for other off-site applications.

This system is categorized as a "dry" or "semi-dry" system in that the end product of the SO_2 conversion reaction is a dry material. Although termed as a dry system, this air pollution control system uses water for evaporative cooling and for the SO_2 reaction. Unlike a wet scrubbing system, however, there is no liquid blow-downstream from the dry system. The "dry" system has been used in low-sulfur coal applications to effectively remove SO_2 from a gas stream with removal efficiencies from 70% to 90%.

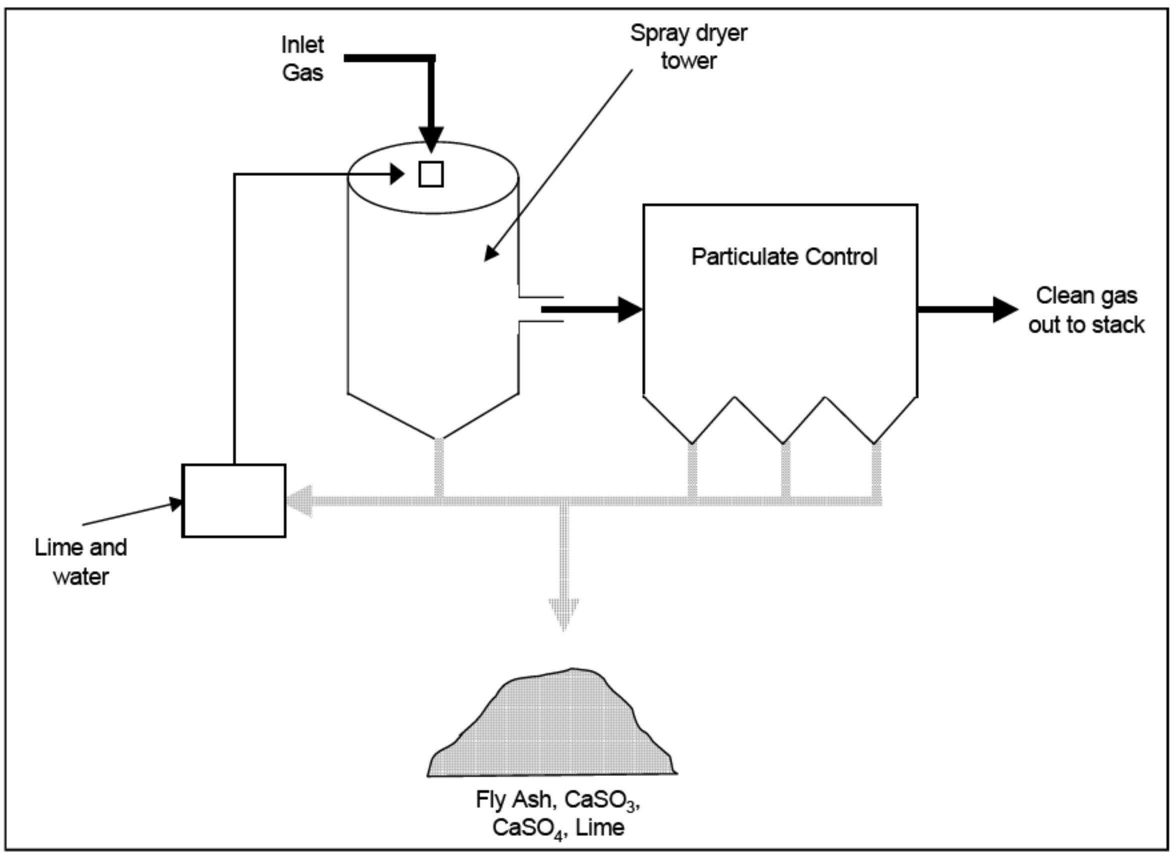

Figure 6-1 Spray Dryer Gas Desulfurization PFD

6.1.3 Dry Sorbent Injection

DSI systems remove SO_2 as well as acid gases and other acid gases through two basic steps. Step one involves injecting a powdered sorbent into the flue gas where it reacts with the SO_2. The sorbents most commonly associated with DSI are Trona and hydrated lime. In Step 2 of the process, the compound is removed by a downstream particulate matter control device such as a baghouse similar to the SDA control. Baghouse units are generally more effective (when combined with DSI) than other particulate control devices, with respect to overall SO_2 reduction.

6.1.4 Wet Scrubber

Wet scrubber systems remove SO_2 from exhaust streams by using an alkaline reagent to form sulfite and sulfate salts. Coal utility boiler wet scrubber systems typically involve the reaction of limestone ($CaCO_3$) or hydrated lime (Ca [OH_2]) and exhaust gas sulfur oxides in a spray absorber tower. Boiler exhaust gas enters at the bottom of the absorber tower, flows vertically through the limestone/ water spray, passes through a mist eliminator to remove re-entrained limestone slurry droplets, and then exits the tower. Ground limestone or hydrated lime in the scrubbing slurry reacts with SO_2 in the flue gas to form calcium sulfite and calcium sulfate (i.e., gypsum).

One of the main environmental issues with wet scrubber systems is that these units generate significant wastewater and wet sludge streams requiring treatment and disposal. Gypsum slurry from the reaction tank is typically treated in a series of hydroclones. Reclaimed water from the hydroclones is returned to the scrubber system and gypsum solids sent to a vacuum filtration system. Gypsum solids from the vacuum filter system may be washed to remove contaminants and then loaded into railcars or trucks for shipment as a byproduct or mixed with fly ash, if necessary, and conveyed to a landfill.

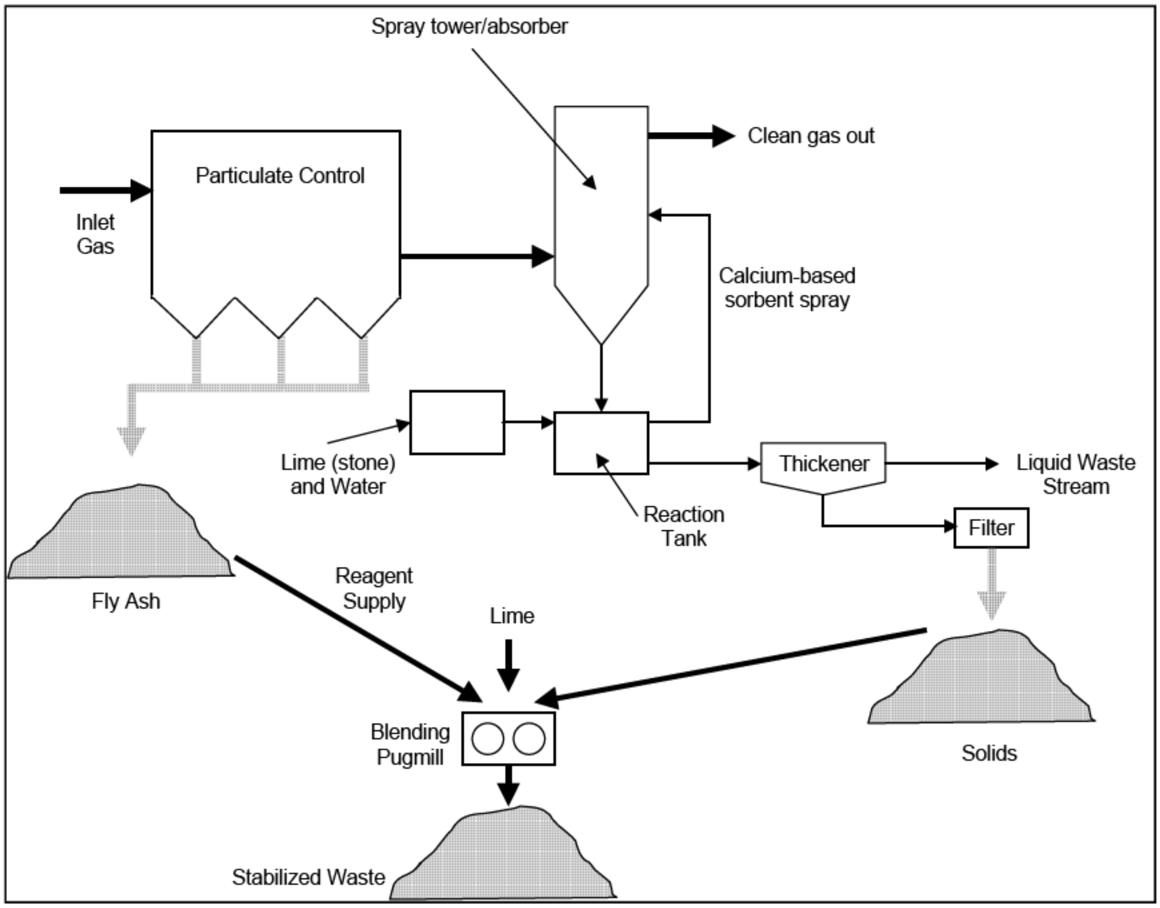

Figure 6-2 Wet Scrubber PFD

A practical issue associated with a wet scrubber system is the complexity of the system. Additional expertise is often needed in specifying, operating, and maintaining such a system, which is more like a chemical plant than a control device. Companies may need more chemical engineers, chemical laboratories, and revised operating and maintenance procedures.

6.1.5 Fuel Modifications

Two types of fuel modifications were considered for the RACT analysis. The first type of fuel modification involves fuel switching whereby higher sulfur fuels are replaced with lower sulfur fuels. The second fuel modification scenario considered was a fuel blending option. For this option, the various fuels are blended where the higher sulfur fuels are restricted to meet a total fuel sulfur blend that results in lower SO_2 emissions.

6.1.5.1 Fuel Switching

Fuel switching involves replacing higher sulfur fuels with lower sulfur fuels. In the case of Boiler House 1 and Boiler House 2, the only logical option is to evaluate eliminating or reducing coke oven gas combustion. Both boiler houses currently combust a combination of COG, BFG, and natural gas. Eliminating BFG was not considered because any BFG not combusted in the boilers would require flaring. This scenario would potentially reduce SO_2 emissions at the boiler houses and increase SO_2

emissions at the flares. Overall SO_2 emissions would likely increase in this situation due to the fact that the boilers would use more natural gas or COG in the boilers to offset the reduction in BFG, while the excess BFG is flared. Eliminating BFG would also require the installation of a new flare to accommodate the increase in BFG flaring.

Eliminating COG from the boilers fuel mixture was considered for this analysis. Currently, not all of the boilers are capable of running on natural gas. The replacement of all the fuel burners in the boilers with low-NO_x burners would be required to eliminate COG. COG is used as a stabilizer fuel for the boilers, and also has a lower nitrogen content than natural gas. The natural gas NO_x emission factor for uncontrolled boilers > 1000 MMBtu/hr is 0.28 lb/MMBtu[3]. Therefore, low-NO_x burners would be needed to meet the MDEQ NO_x limitation of 0.25 lb/MMBtu if natural gas was used as the only fuel. Currently, USS GLW meets this limitation by blending natural gas with other fuels, which reduces the composite nitrogen content of the fuel combusted below the MDEQ NO_x limit. In addition, new control panels would be required for each boiler. The diameter of the natural gas lines would also need to be increased to accommodate the additional natural gas flow required to offset the COG. Fuel switching has been determined as technically feasible for this application although to retrofit each of the boilers with low-NO_x burners and increase the natural gas line would require extensive modifications to the facility.

6.1.5.2 Fuel Blending Modifications

Various fuel blending scenarios were evaluated for this RACT analysis. It was assumed that USS GLW would continue to use the same fuels (i.e. COG, BFF, and natural gas) for future operations, but would utilize various composites of these fuels to lower the sulfur content of the fuel combusted on a lb/MMBtu basis. An evaluation of the historical fuel blends was examined for this exercise. During calendar year 2013, the average emission rate for USS GLW's emission units subject to this RACT analysis was 0.32 lb/MMBtu. It should be noted that a short-term emission rate would be significantly higher than the annual average emission rate observed in 2013. Fuel blending was determined to be an effective and reasonable way to reduce SO_2 emissions and is considered technically feasible.

6.1.6 Increased Dispersion

Air dispersion modeling was conducted to determine the change in concentration based on altering the stack parameters of the existing boilers. The increased dispersion option was conducted by utilizing the modeling methodology specified in Section 5.1. As mentioned in Section 5.1.5, the concentration was determined at the SWHS SO_2 monitor. A baseline model was run to determine the 1-hr SO_2 concentration (H4H) with the existing stack parameters and potential to emit (PTE) short-term emissions. A separate model was conducted for a combined stack for both boiler houses and compared to the baseline model results.

[3] AP-42 Chapter 1.4, Table 1.4-1, July 1998

6.1.6.1 Baseline Model

In order to obtain the change in 1-hr SO_2 concentration (H4H) at the SWHS monitor, a baseline concentration had to be determined for each source group. The baseline model was run for Boiler House 1 and Boiler House 2 separately. The baseline modeled source parameters were supplied by USS in the modeling input file and are shown below in Table 6-3 and Table 6-4. The emissions listed in the tables correspond to the short-term SO_2 potential to emit, which was supplied to CB&I by USS.

Table 6-3
Baseline Boiler House 1 Model Parameters

Source ID	Description	Base Elevation (m)	Height (m)	Diameter (m)	Exit Velocity (m/s)	Exit Temperature (K)	SO_2 Emission Rate (g/s)
ZI1B1	Zug Island No. 1 BH Boiler No. 1	176.51	20.73	1.68	19.1058	560.93	1.642
ZI1B2	Zug Island No. 1 BH Boiler No. 2	176.51	20.73	1.68	19.1058	560.93	1.642
ZI1B3	Zug Island No. 1 BH Boiler No. 3	176.51	20.73	1.68	18.3984	560.93	3.415
ZI1B4	Zug Island No. 1 BH Boiler No. 4	176.51	24.69	1.68	18.3984	560.93	3.415
ZI1B5	Zug Island No. 1 BH Boiler No. 5	176.51	24.69	1.68	18.3984	560.93	3.415

Table 6-4
Baseline Boiler House 2 Model Parameters

Source ID	Description	Base Elevation (m)	Height (m)	Diameter (m)	Exit Velocity (m/s)	Exit Temperature (K)	SO_2 Emission Rate (g/s)
ZI2B1	Zug Island No. 2 BH Boiler No. 1	176.76	26.82	2.97	7.35757	560.93	2.146
ZI2B2	Zug Island No. 2 BH Boiler No. 2	176.78	26.82	2.97	7.35757	560.93	2.146
ZI2B3	Zug Island No. 2 BH Boiler No. 3	176.8	26.82	2.97	7.35757	560.93	2.146
ZI2B4	Zug Island No. 2 BH Boiler No. 4	176.82	26.82	2.97	7.35757	560.93	2.146
ZI2B5	Zug Island No. 2 BH Boiler No. 5	176.84	26.82	2.97	7.35757	560.93	2.146

Sources ZI1B1 through ZI1B5 were combined into the source group ZIB1 to obtain the total impact from all of Boiler House 1 boilers. Similarly, sources ZI2B1 though ZI2B5 were combined into the source group ZIB2 to determine the total impact form all of Boiler House 2 boilers.

6.1.6.2 Combined Stack Model

The increased dispersion option considered that all five boilers in Boiler House 1 would be combined into a common stack. Similarly, the increased dispersion option also considered that all five boilers in Boiler House 2 would be combined into a common stack (separate from Boiler House 1).

There are several structures that are nearby each of the proposed combined stacks that can influence the stack height. CB&I utilized the USEPA Building Input Profile Program (BPIP) to obtain the Good Engineering Stack Height (GEP) for the common stacks. The BPIP output file indicated that GEP stack height for both the Boiler House 1 combined stack and the Boiler House 2 combined stack should be 65 meters. It was also assumed that the combined stack for Boiler House 1 would be located centrally to the existing Boiler House 1 boiler stacks, and the combined stack for Boiler House 2 would be located centrally to the existing Boiler House 2 boiler stacks.

The baseline actual exhaust volumetric flowrate of each of the boilers (separately for each boiler house) was added together to determine the combined stack actual exhaust volumetric flowrate. The exit velocity of the combined stack was assumed to be 3,000 ft/min (15.24 m/s), which is a more realistic exit velocity than the exit velocities of the baseline model. The combined stack diameter was then calculated for each boiler house combined stack by using the volumetric flowrate and exit velocity. It was also assumed that the exhaust temperature of the combined stack would be equal to the stack temperature of the baseline model.

The stack parameters of the combined stack models are shown below in Table 6-5 and

Table 6-6. The 1-hr SO_2 concentration (H4H) was determined separately for each source group.

Table 6-5
Combined Stack Boiler House 1 Model Parameters

Source ID	Description	Base Elevation (m)	Height (m)	Diameter (m)	Exit Velocity (m/s)	Exit Temperature (K)	SO_2 Emission Rate (g/s)
BH1	Combined Stack Boiler House 1	176.51	65	4.1605	15.24	560.93	13.529

Table 6-6
Combined Stack Boiler House 2 Model Parameters

Source ID	Description	Base Elevation (m)	Height (m)	Diameter (m)	Exit Velocity (m/s)	Exit Temperature (K)	SO_2 Emission Rate (g/s)
BH2	Combined Stack Boiler House 2	176.8	65	4.6147	15.24	560.93	10.73

6.1.6.3 Results

The sources listed above were added into the 1-hr SO_2 model along with the SWHS monitor receptor to determine the change in impact of the combined stack over baseline. AERMOD automatically generates the H4H for the 1-hr SO_2 at the receptor for the specific source groups. The change in concentration from baseline to combined stack modeling runs is shown below in Table 6-7.

Table 6-7
1-hr SO_2 Modeling Results Comparison Boiler House 1 and 2

Source Group	Source Description	H4H SO_2 1-hr Concentration $\mu g/m^3$
ZIB1	Boiler House 1 stacks at existing stack conditions	18.24
BH1	Combined stack for Boiler House 1	4.46
	Change in Concentration	**13.78**
ZIB2	Boiler House 2 stacks at existing stack conditions	11.19
BH2	Combined stack for Boiler House 2	2.92
	Change in Concentration	**8.27**

As shown in the table above, combining the respective boilers in each boiler house into a common stack at GEP stack height results in a decrease in 1-hr SO_2 concentration (H4H) at the SWHS SO_2 monitor. It is important to note that the model was conducted with the potential emissions for the emission sources. The change in 1-hr SO_2 concentration at the SWHS monitor will be less if actual emissions are evaluated. However, it is assumed that a reduction over baseline would still occur if actual emissions are evaluated. Increasing dispersion by increasing stack height has been determined as technically feasible for this application although to retrofit each of the boilers to create a combined stack would require extensive modifications to the facility.

6.2 Technical Feasibility and Ranking

Although each of the add-on control technologies presents a series of challenges for implementation, all were considered theoretically feasible. A more extensive study would be needed before each of these add-on control devices could be considered technically feasible. At a minimum, this study must evaluate:

- pilings installation for support of the control device,
- evaluating the footprint of the control device units and determining available real estate, and
- increasing the capacity of the wastewater/stormwater outfalls to support the additional load from the wet scrubber

Since this is a retrofit situation, there is limited real estate available especially in and around the boiler houses. It is also CB&I's understanding that the water table is shallow in these areas. This would require extensive piling prior to construction to support the weight of these units and prevent any type of settling issues. Further, the current wastewater/stormwater outfalls are at maximum permitted and physical capacity. Additional research would be required to determine if a wet scrubber is technically feasible due to the additional load from the wastewater treatment system. The fuel switching, fuel blending, and increased dispersion options discussed previously were all considered technically feasible, although increased dispersion could require some piling to support the new stack.

Table 6-8 below provides a summary of the control options considered for this RACT analysis, as well as the associated emission rates, negative impacts, and average cost effectiveness. The cost effectiveness was evaluated on a dollars per ton basis, using 2010 SO_2 emission rates as a basis, with the exception of increased dispersion which was evaluated on a dollars per reduction in ground level impact SO_2 concentration. A detailed breakdown of the costs calculations are provided in Appendix B.

Table 6-8
Ranking of SO_2 Control Options

Available Control Alternatives	Technically Feasible?	Selected RACT option?	Negative Impacts	Emission Rate (lb/MMBtu)	Average Cost Effectiveness ($/ton)[4]	Average Cost Effectiveness ($/ton)[5]
Spray Dryer Absorber Boiler House 1	Potentially	No	Economic, Energy, Environmental	0.026	$34,644	--
Spray Dryer Absorber Boiler House 2	Potentially	No	Economic, Energy, Environmental	0.037	$20, 400	--
Dry Sorbent Injection Boiler House 1	Potentially	No	Economic, Energy, Environmental	0.057	$26,640	--
Dry Sorbent Injection Boiler House 2	Potentially	No	Economic, Energy, Environmental	0.087	$14,890	--
Wet Scrubber Boiler House 1	Potentially	No	Economic, Energy, Environmental	0.026	$40,747	--
Wet Scrubber Boiler House 2	Potentially	No	Economic, Energy, Environmental	0.037	$24,848	--

[4] The fuel switching costs for natural gas were based on the U.S. Energy Information Administration (EIA) short-term energy outlook- released February 2014. Using the EIA costs estimates is not reasonable to estimate the cost impact for fuel switching. A more representative cost estimate would be based on the historical natural gas costs for USS, which would result in a significantly higher average cost effectiveness as shown in the adjacent column in Table 6-8.

[5] Fuel switching costs based on average historic USS natural gas prices over the past 10 years.

*Fuel Switching Boiler House 1	Yes	No	Economic, Environmental	0.052	$16,904	$19,999
*Fuel Switching Boiler House 2	Yes	No	Economic, Environmental	0.063	$12,133	$16,168
Fuel Blending	Yes	Yes	Economic	0.40	NA	--
*Increased Dispersion Boiler House 1[6]	Yes	No	Economic, Energy	NA	$119,259	--
*Increased Dispersion Boiler House 2[7]	Yes	No	Economic, Energy	NA	$210,934	--

* Fuel switching and increased dispersion do not result in reduced SO_2 emissions in the vicinity of USS GLW. Any excess COG not consumed at USS, due to fuel switching, would require flaring at the adjacent coke plant. Increased dispersion would potentially decrease the ground level impact of SO_2 emissions, but does not result in less emissions from the respective USS emission units.

6.3 Selection of RACT

Fuel switching is not economically feasible for Boiler House 1 or 2. Moreover, it does not result in any reduction of overall SO_2 emissions from the area, and could actually increase overall SO_2 emissions since additional natural gas would be burned to substitute for the loss in COG, while the COG is being flared at the adjacent coke plant simultaneously. Fuel switching could also trigger PSD permitting for certain pollutants since there could be an actual emissions increase above the PSD SER. Therefore, fuel switching was rejected as RACT.

As shown in Table 6-8, CB&I recommends that USS GLW proposes to utilize fuel blending to reduce SO_2 emissions by accepting an allowable emission rate of 0.40 lb/MMBtu on an annual average basis for the combined emission rate for Boiler House 1, Boiler House 2, Flares, and Hot Strip Mill Furnaces. A short-term average would require a considerably higher emission rate to account for fuel blending fluctuations. Further, in the event operations is interrupted due to process upsets and temporary fuel loss situations (e.g. loss of BFG), an alternate SO_2 emission limit for this operating scenario would need to be established. An emission rate of 0.40 lb/MMBtu represents the emission rate obtained by USS GLW during the 2013 calendar year with a 25% increase to account for variability. This RACT proposal also results in a 15% reduction of SO_2 levels from years that were used to designate the area as nonattainment and subsequently modeled by MDEQ and satisfies the definition of RACT. All other alternative control methods were rejected due to the cost effectiveness and/or questionable technical feasibility.

[6] Average cost effectiveness provided on a dollars per microgram per cubic meter ($\mu g/m^3$) reduction in ground level SO_2 concentration

[7] Average cost effectiveness provided on a dollars per microgram per cubic meter ($\mu g/m^3$) reduction in ground level SO_2 concentration. Increased dispersion for Boiler House 2 results in less ambient impact reduction of SO_2.

7.0 Hot Strip Mill Reheat Ovens/Furnaces RACT

7.1 Available Control Technologies

As previously discussed, no specific add-on SO_2 controls were identified in the RBLC search for gas-fired fuels. Although coal fired boilers have higher uncontrolled SO_2 emissions than gaseous fired fuels, the gas stream was considered somewhat comparable to the sulfur gas stream concentration of COG that is utilized in the USS GLW hot strip mill reheat ovens/furnaces. Therefore, these add-on controls were evaluated as a theoretically feasible control option. Generally, there are three types of add-on SO_2 controls applicable to a coal-fired boiler: dry (i.e., DSI), semi-dry (i.e., SDA), and wet (i.e., wet scrubber). Wet scrubbers and SDAs are collectively referred to as FGD) units. DSI may be used in boilers by dry injection of sorbents such as hydrated lime or Trona into the duct system; however, the level of control that is achievable is not comparable to FGD control systems.

Other types of alternative control techniques identified for the boiler houses are also applicable to the reheat ovens/furnaces and include fuel switching, fuel blending, and increased dispersion. Fuel switching involves substituting a lower sulfur content fuel for higher sulfur content fuels. At USS GLW, the highest sulfur fuel is COG followed by BFG and natural gas. Fuel blending, as defined in this analysis, includes using various fuel blends to achieve an overall fuel sulfur level thereby reducing the amount of SO_2 that is generated in the combustion process. Increased dispersion does not have the effect of decreasing overall SO_2 emissions, but can decrease the ground level impact of those emissions. These additional non-add-on controls have been included in this RACT analysis for the reheat ovens/furnaces. The pre-combustion scrubbing of BFG was not considered in this evaluation since no existing data was identified in the RBLC database other than previous BACT determinations eliminating this option as not technically feasible.

7.1.1 Summary of RACT/BACT/LAER Clearinghouse Information

CB&I conducted a search of the RBLC database for SO2 controls for similar emissions units as those in the USS GLW RACT request by MDEQ. No add-on controls were identified in the RBLC search for gas-fired ovens/furnaces in the various size ranges. Detailed information on the RBLC search is provided in Appendix A. In addition, no add-on controls specific to the furnaces were identified in the RBLC search for the steel and iron industry under process types 81.200, 81.300, and 81.400. The most prevalent type of control identified in the RBLC for gaseous fuel for all industry boilers and furnaces is to limit the sulfur content of the fuel purchased and/or utilizing a specific type of fuel (i.e. natural gas) with a low-sulfur content. Therefore, these types of controls were evaluated as part of this RACT analysis in addition to potential add-on controls. A summary of the RBLC search is provided in Appendix A.

7.1.2 Fuel Modifications

Two types of fuel modifications were considered for the RACT analysis. The first type of fuel modification involves fuel switching whereby higher sulfur fuels are replaced with lower sulfur fuels. The second fuel modification scenario considered was a fuel blending option. For this option, the various fuels are blended where the higher sulfur fuel usage is restricted to meet a total fuel sulfur blend that results in lower SO_2 emissions.

7.1.2.1 Fuel Switching

Fuel switching involves replacing higher sulfur fuels with lower sulfur fuels. In the case of the reheat ovens/furnaces, the only logical option is to evaluate eliminating or reducing coke oven gas combustion since natural gas has the lowest sulfur content of any of the fuels utilized in the mill. The reheat ovens/furnaces in the hot strip mill combust COG and natural gas.

In order to switch the reheat ovens/furnaces to 100% natural gas, the replacement of all the fuel burners with low-NOx burners would be required. COG has a lower nitrogen content than natural gas. The natural gas NOx emission factor for uncontrolled boilers > 1000 MMBtu/hr is 0.28 lb/MMBtu. Therefore, low-NOx burners would be needed to meet the MDEQ nitrogen oxide (NOx) limitation of 0.25 lb/MMBtu assuming the reheat ovens/furnaces would strictly operate on natural gas. Currently, USS GLW meets this limitation by blending natural gas with COG, which reduces the composite nitrogen content of the fuel combusted below the MDEQ NOx limit. The diameter of the natural gas lines would also need to be increased to accommodate the additional natural gas flow required to offset the COG. To retrofit each of the reheat ovens/furnaces with low-NOx burners would require extensive engineering, labor, and production downtime of the ovens/furnaces. Substituting COG with BFG was not considered due to the low Btu value of BFG, and the fact that there is no current BFG fuel line near the hot strip mill. Therefore, the COG to BFG fuel switching alternative was not considered a technically feasible option.

7.1.2.2 Fuel Blending Modifications

Various fuel blending scenarios were evaluated for this RACT analysis. It was assumed that USS would continue to utilize the same fuels (i.e. COG and natural gas) for future operations, but would use various composites of these fuels to lower the sulfur content of the fuel combusted on a lb/MMBtu basis. An evaluation of the potential and recent historical fuel blends was examined for this exercise. During calendar year 2013, the average emission rate for USS GLW's emission units subject to this RACT analysis was 0.32 lb/MMBtu. It should be noted that a short-term emission rate would be significantly higher than the annual average emission rate observed in 2013. Fuel blending was determined to be an effective and reasonable way to reduce SO_2 emissions and is considered technically feasible.

7.1.3 Increase Dispersion

Air dispersion modeling was conducted to determine the change in concentration based on altering the stack parameters of the existing hot strip mill reheat ovens/furnaces. The increased dispersion option was conducted by utilizing the modeling methodology specified in Section 5.1. As mentioned in Section 5.1.5, the concentration was determined at the SWHS SO_2 monitor. A baseline model was run to determine the 1-hr SO_2 concentration (H4H) with the existing stack parameters and potential to emit (PTE) short-term emissions.

7.1.3.1 Baseline Model

In order to obtain the change in 1-hr SO_2 concentration (H4H) at the SWHS monitor, a baseline concentration had to be determined for the source group. The baseline modeled source parameters for the hot strip mill reheat ovens/furnaces were supplied by USS in the modeling input file and are shown below in Table 7-1. The emissions listed in the tables correspond to the short-term SO_2 potential to emit, which was supplied to CB&I by USS.

Table 7-1
Baseline Reheat Ovens/Furnaces Model Parameters

Source ID	Description	Base Elevation (m)	Height (m)	Diameter (m)	Exit Velocity (m/s)	Exit Temperature (K)	SO_2 Emission Rate (g/s)
HSMF1	80" HSM Slab Reheat Furnace 1	175.27	31.09	4.27	6.06932	477.59	15.731
HSMF2	80" HSM Slab Reheat Furnace 2	175.26	31.09	4.27	6.12809	477.59	15.732
HSMF3	80" HSM Slab Reheat Furnace 3	175.25	31.09	4.27	6.12809	477.59	15.732
HSMF4	80" HSM Slab Reheat Furnace 4	175.23	31.09	4.27	6.12809	477.59	15.732
HSMF5	80" HSM Slab Reheat Furnace 5	175.23	31.09	4.27	6.30447	477.59	15.732

7.1.3.2 Combined Stack Model

The increased dispersion option considered that all five ovens/furnaces would be combined into a common stack. There are several structures that are nearby the proposed combined stack that can influence the stack height. CB&I utilized the BPIP to obtain the GEP for the common stack. The BPIP output file indicated that GEP stack height for both the reheat ovens/furnaces combined stack should be 65 meters. It was also assumed that the combined stack located centrally to the existing ovens/furnace stacks.

The baseline actual exhaust volumetric flowrate of each of the ovens/furnaces was added together to determine the combined stack actual exhaust volumetric flowrate. The exit velocity of the combined stack was assumed to be 3,000 ft/min (15.24 m/s), which is a more realistic exit velocity than the exit velocities of the baseline model. The combined stack diameter was then calculated for the combined stack by using the volumetric flowrate and exit velocity. It was also assumed that the exhaust temperature of the combined stack would be equal to the stack temperature of the baseline model.

The stack parameters of the combined stack models are shown below in Table 7-2.

Table 7-2
Combined Stack Reheat Ovens/Furnaces Model Parameters

Source ID	Description	Base Elevation (m)	Height (m)	Diameter (m)	Exit Velocity (m/s)	Exit Temperature (K)	SO_2 Emission Rate (g/s)
FURN	Combined Stack Reheat Furnaces	175.23	65	6.0655	15.24	477.59	78.659

7.1.3.3 Results

The sources listed above were added into the 1-hr SO_2 model along with the SWHS monitor receptor to determine the change in impact of the combined stack over baseline. AERMOD automatically generates the H4H for the 1-hr SO_2 at the receptor for the specific source groups. The change in concentration from baseline to combined stack modeling runs is shown below in Table 7-3.

Table 7-3
1-hr SO_2 Modeling Results Comparison Reheat Ovens/Furnaces

Source Group	Source Description	H4H SO_2 1-hr Concentration $\mu g/m^3$
HSMF	Reheat furnaces at existing stack conditions	45.31
FURN	Combined stack for Reheat Furnaces	14.86
	Change in Concentration	**30.45**

As shown in the table above, combining the ovens/furnaces into a common stack at GEP stack height results in a decrease in 1-hr SO_2 concentration (H4H) at the SWHS SO_2 monitor. It is important to note that the model was conducted with the potential emissions for the emission sources. The change in 1-hr SO_2 concentration at the SWHS monitor will be less if actual emissions are evaluated. However, it is assumed that a reduction over baseline would still occur if actual emissions are evaluated. Increasing dispersion by increasing stack height has been determined as technically feasible for this application although to retrofit each of the ovens/furnaces to create a combined stack would require extensive modifications to the facility.

7.2 Technical Feasibility and Ranking

Although all add-on controls (i.e. SDA, DSI, and wet scrubber) have all been considered theoretically feasible, a more extensive study would be needed to conclude that each of these technologies are technically feasible. This is a retrofit situation which presents a series of challenges for add-on control equipment that require a large footprint. It is also CB&I's understanding that the water table is shallow at the USS GLW facility. This would require extensive piling prior to construction to support the weight of these units and prevent any type of settling issues. Further, the current wastewater/stormwater outfalls are at maximum permitted and physical capacity. Additional research would also be required to determine if a wet scrubber is technically feasible due to the additional wastewater load from the wastewater treatment system. The fuel switching, fuel blending, and increased dispersion options discussed previously were all considered technically feasible for the hot mill, although increased dispersion could require some piling to support the new stack.

Table 7-4 below provides a summary of the control options considered for this RACT analysis, as well as the associated emission rates, negative impacts, and average cost effectiveness. The cost effectiveness was evaluated on a dollars per ton basis, using 2010 SO_2 emission rates as a basis, with the exception of increased dispersion which was evaluated on a dollars per reduction in ground level impact concentration. A detailed breakdown of the costs calculations are provided in Appendix B.

Table 7-4
Ranking of SO_2 Control Options

Available Control Alternatives	Technically Feasible?	Selected RACT option?	Negative Impacts	Emission Rate (lb/MMBtu)	Average Cost Effectiveness (\$/ton)[8]	Average Cost Effectiveness (\$/ton)[9]
Spray Dryer Absorber	Potentially	No	Economic, Energy, Environmental	0.046	$10,650	--
Dry Sorbent Injection	Potentially	No	Economic, Energy, Environmental	0.101	$8,081	--
Wet Scrubber	Potentially	No	Economic, Energy, Environmental	0.046	$10,178	--
*Fuel Switching	Yes	No	Economic, Environmental	0.001	$9,129	$14,295
Fuel Blending	Yes	Yes	Economic	0.40	NA	--
*Increased Dispersion[10]	Yes	No	Economic, Energy	NA	$82,934	--

* Fuel switching and increased dispersion do not result in reduced SO_2 emissions in the vicinity of USS GLW. Any excess COG not consumed at USS, due to fuel switching, would require flaring at the adjacent coke plant. Increased dispersion would potentially decrease the ground level impact of SO_2 emissions, but does not result in less emissions from the respective USS emission units.

7.3 Selection of RACT

Fuel switching is not economically feasible. Further, it does not result in any reduction of overall SO_2 emissions from the area, and could actually increase overall SO_2 emissions since additional natural gas

[8] The fuel switching costs for natural gas were based on the U.S. Energy Information Administration (EIA) short-term energy outlook- released February 2014. Using the EIA costs estimates is not reasonable to estimate the cost impact for fuel switching. A more representative cost estimate would be based on the historical natural gas costs for USS, which would result in a significantly higher average cost effectiveness as shown in the adjacent column in Table 7-4.

[9] Fuel switching costs based on average historic USS natural gas prices over the past 10 years.

[10] Average cost effectiveness provided on a dollars per microgram per cubic meter ($\mu g/m^3$) reduction in ground level SO_2 concentration

would be burned to substitute for the loss in COG, while the COG is being flared at the adjacent coke plant simultaneously. Fuel switching could also trigger PSD permitting since there could be an actual increase above the SER for certain pollutants. Therefore, fuel switching was rejected as RACT.

As shown in Table 7-4, CB&I recommends that USS GLW proposes to utilize fuel blending to reduce SO_2 emissions by accepting an allowable emission rate of 0.40 lb/MMBtu on an annual average basis for the combined emission rate for Boiler House 1, Boiler House 2, Flares, and Hot Strip Mill Furnaces. A short-term average would require a considerably higher emission rate to account for fuel blending fluctuations. In the event operations is interrupted due to process upsets and temporary fuel loss situations (e.g. loss of natural gas), an alternate SO_2 emission limit for this operating scenario would need to be established. An emission rate of 0.40 lb/MMBtu represents the emission rate obtained by USS GLW during the 2013 calendar year with a 25% increase to account for variability. This RACT proposal also results in a 15% reduction of SO_2 levels from years that were used to designate the area as nonattainment and subsequently modeled by MDEQ, and satisfies the definition of RACT. All other alternative control methods were rejected due to the cost effectiveness, and/or questionable technical feasibility.

8.0 Flare RACT

8.1 Available Control Technologies

No specific control technologies were identified for SO_2 control from flares. A search of the RBLC database did not result in any identified SO_2 controls other than limiting the sulfur content of natural gas as a supplemental fuel. USS does not have any control over the sulfur content of the natural gas available. Therefore, any type of sulfur restriction for natural gas combustion could not be guaranteed by USS since the fuel is provided by a third party utility. Further, this control would not result in a significant decrease in SO_2 emissions from flaring.

8.1.1 Increase Dispersion

The associated flares (A-1 Flare Stack and D-4 Flare Stack) were not evaluated in the increased dispersion option since these existing flares are open flares. It is not feasible to increase the stack height of these flares. Additionally, it is assumed that the emissions from the flares already are greatly dispersed due to the flame temperature and flame height.

8.2 Technical Feasibility and Ranking

The two identified controls for flaring were both considered not technically feasible. The increased dispersion option does not result in lower ground level concentrations of SO_2. In addition, limiting sulfur in the natural gas supply is not a feasible option since USS has no control over the natural gas supply and has no alternative means of purchasing natural gas from a different supplier.

Table 8-1 below provides a summary of the control options considered for this RACT analysis, as well as the associated emission rates, negative impacts, and average cost effectiveness.

Table 8-1
Ranking of SO_2 Control Options

Available Control Alternatives	Technically Feasible?	Selected RACT option?	Negative Impacts	Emission Rate (lb/MMBtu)	Average Cost Effectiveness ($/ton)
Limit sulfur content of supplemental natural gas	No	No	Economic	NA	NA
Increased Dispersion	No	No	Economic, Energy	NA	NA

8.3 Selection of RACT

Although there is no means to actually change the fuel blend for flaring, CB&I recommends that USS GLW propose to utilize fuel blending to reduce SO_2 emissions to an allowable emission rate of 0.40 lb/MMBtu on an annual average basis for the combined emission rate for Boiler House 1, Boiler House 2, Flares, and Hot Strip Mill Furnaces. Again, a short-term average would require a considerably higher emission rate to account for process fluctuations. An emission rate of 0.40 lb/MMBtu represents the emission rate obtained by USS GLW during the 2013 calendar year with a 25% increase to account for variability. This RACT proposal also results in a 15% reduction of SO_2 levels from years that were used to designate the area as nonattainment and subsequently modeled by MDEQ previous years, and satisfies the definition of RACT. All other alternative control methods were rejected due to the cost effectiveness and/or questionable technical feasibility.

APPENDIX A
SUMMARY OF SO_2 CONTROL DETERMINATIONS PER USEPA'S RACT/BACT/LAER DATABASE

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas > 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	Z-HIGH MILL WITH MIST ELIMINATOR (LO42) (MULTIPLE EMISSION POINTS)				Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LO43).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS -FIRED ANNEALING FURNACE (LA43) (MULTIPLE EMISSION POINTS)	NATURAL GAS	196.4	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LA43).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	2 ACID REGENERATION LINES EACH WITH CAUSTIC SCRUBBERS & COMMON SCR (LO72) (MULTIPLE EMISSION POINTS)	NATURAL GAS	20600	T/YR	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE 2 ACID REGENERATION LINES EACH WITH CAUSTIC SCRUBBER & COMMON SCR (LO72).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	DEGREASING WITH WET SCRUBBER (LO52) (MULTIPLE EMISSION POINTS)		60	T/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LO53).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	DEGREASING WITH WET SCRUBBER (MULTIPLE EMISSION POINTS)		60	T/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE.
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED BATCH ANNEALING FURNACES (LA63, LA64)	NATURAL GAS	33.4	MMBTU each	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED PASSIVE ANNEALING FURNACE (LO41)	NATURAL GAS	27.2	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	4 CONTINUOUS HOT DIP GALVANIZING LINE (EACH LINE WITH SAME MULTIPLE EMISSION POINTS)				Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 EMISSIONS FOR THE ANTI-CORROSIVE COATING WITH PRE & POST DRYERS.
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	4 CONTINUOUS HOT DIP GALVANIZING LINE (EACH LINE WITH SAME MULTIPLE EMISSION POINTS)				Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 EMISSIONS FOR THE ANNEALING FURNACES.
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	MELTSHOP - LO (MULTIPLE EMISSION POINTS)		126	T/H	Sulfur Dioxide (SO2)		0.15	LB/T	0			THIS COVERS SO2 EMISSIONS FOR THE AOD CONVERTER WITH ELEPHANT HOUSE & 2 LMFS VENTED TO COMMON BAGHOUSE (LO2).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	MELTSHOP - LO (MULTIPLE EMISSION POINTS)		126	T/H	Sulfur Dioxide (SO2)		0.15	LB/T	0			THIS COVERS SO2 FOR THE TPH EAF WITH DEC & ELEPHANT HOUSE VENTED TO BAGHOUSE (LO1).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	TPH ELECTRIC ARC FURNACE WITH DEC & ELEPHANT HOUSE VENTED TO BAGHOUSE 3 (LA1) (MULTIPLE EMISSION POINTS)	NATURAL GAS	126	T/H	Sulfur Dioxide (SO2)		0.15	LB/T	0			THIS COVERS SO2 FOR THE TPH ELECTRIC ARC FURNACE WITH DEC & ELEPHANT HOUSE VENTED TO BAGHOUSE 3 (LA1).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	TPH ELECTRIC ARC FURNACE WITH DEC & ELEPHANT HOUSE VENTED TO BAGHOUSE 3 (LA1) (MULTIPLE EMISSION POINTS)	NATURAL GAS	126	T/H	Sulfur Dioxide (SO2)		0.15	LB/T	0			THIS COVERS SO2 FOR THE ARGON-OXYGEN DECARBURIZATION FURNACE WITH ELEPHANT HOUSE & 2 LADLE METALLURGY STATIONS VENTED TO COMMON BAGHOUSE.
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	169	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED REHEAT FURNACE (LA 21).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	169	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE 3 COIL DRUM FURNACES (LA24-LA26).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	169	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE PLATE ANNEALING FURNACE (LA27).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	BAL STEAM SWEEP WITH MIST ELIMINATOR (LA66) (MULTIPLE EMISSION POINTS)		12.6	T/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LA70).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	3 NATURAL GAS-FIRED BOILERS WITH ULNB & EGR (537-539)	NATURAL GAS	64.9	MMBTU each	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	HOT STRIP MILL (MULTIPLE EMISSION POINTS)	NATURAL GAS	690	T/H	Sulfur Dioxide (SO2)		0 006	LB/MMBTU	0			THIS COVERS SO2 EMISSIONS FROM THE 4 NATURAL GAS-FIRED WALKING BEAM REHEAT FURNACES.
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	HCL ACID REGENERATION (MULTIPLE EMISSION POINTS)	NATURAL GAS	3.77	T/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 EMISSIONS FOR THE 2 REGENERATION TRAINS WITH CAUSTIC SCRUBBER (5-10).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED BATCH ANNEALING FURNACE (535)	NATURAL GAS	99	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AL-0251	HILLABEE ENERGY CENTER	AL	09/24/2008 ACT	COMBUSTION TURBINE	NATURAL GAS	2142	MMBTU/H	Sulfur Dioxide (SO2)	PIPELINE QUALITY NATURAL GAS	15.2	LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AL-0251	HILLABEE ENERGY CENTER	AL	09/24/2008 ACT	FUEL HEATER	NATURAL GAS	11640000	BTU	Sulfur Dioxide (SO2)	PIPELINE QUALITY NATURAL GAS	0		0			Contact permitting agency for emissions information.
AL-0251	HILLABEE ENERGY CENTER	AL	09/24/2008 ACT	EMERGENCY GENERATOR	DIESEL	600	EKW	Sulfur Dioxide (SO2)	LOW SULFUR DIESEL FUEL	0		0			Contact permitting agency for emissions information.
AR-0043	PINE BLUFF ENERGY LLC	AR	02/27/2001 ACT	TURBINE, SIMPLE CYCLE	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	0.0006	LB/MMBTU	0			
AR-0043	PINE BLUFF ENERGY LLC	AR	02/27/2001 ACT	TURBINE, COMBINED CYCLE, FUEL OIL	FUEL OIL	170	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUELS - 0.05% S BY WT	0.0489	LB/MMBTU	0			
AR-0043	PINE BLUFF ENERGY LLC	AR	02/27/2001 ACT	BURNER, DUCT	NATURAL GAS	315	MMBTU/H	Sulfur Dioxide (SO2)	CLEAN FUELS.	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
AR-0043	PINE BLUFF ENERGY LLC	AR	02/27/2001 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL - < 0.05% S BY WT	0.0006	LB/MMBTU	0			
AR-0091	NUCOR-YAMATO STEEL COMPANY	AR	04/05/2006 ACT	CASTRIP LMF				Sulfur Dioxide (SO2)	LOW SULFUR COKE USAGE	54	LB/H	0 36	LB/T STEEL		
AR-0091	NUCOR-YAMATO STEEL COMPANY	AR	04/05/2006 ACT	CASTRIP VTD BOILER	NATURAL GAS			Sulfur Dioxide (SO2)	FUEL SPECIFICATION: NATURAL GAS	0.1	LB/H	0.0006	LB/MMBTU		
AR-0091	NUCOR-YAMATO STEEL COMPANY	AR	04/05/2006 ACT	CASTRIP MISCELLANEOUS DRYERS AND PREHEATERS	NATURAL GAS			Sulfur Dioxide (SO2)	FUEL SPECIFICATION: NATURAL GAS	0.0006	LB/MMBTU	0			
AR-0094	JOHN W. TURK JR. POWER PLANT	AR	11/05/2008 ACT	PC BOILER	PRB SUB-BIT COAL	6000	MMBTU/H	Sulfur Dioxide (SO2)	DRY FLUE GAS DESULFURIZATION (SPRAY DRY ADSORBER)	0.08	LB/MMBTU	0			LOWER LIMIT IS FOR BURNING COAL <= 0.45% BY WEIGHT SULFUR CONTENT. ALSO 480 LB/HR 24 HOUR SO2 LIMIT AT ALL TIMES
AR-0094	JOHN W. TURK JR. POWER PLANT	AR	11/05/2008 ACT	AUXILIARY BOILER	NATURAL GAS	555	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AR-0094	JOHN W. TURK JR. POWER PLANT	AR	11/05/2008 ACT	EMERGENCY GENERATOR AND FIRE PUMP ENGINE				Sulfur Dioxide (SO2)	LOW SULFUR DIESEL USE	0 007	G/KW-H	0			BASED ON USE OF LOW SULFUR DIESEL USE
FL-0252	FORT PIERCE REPOWERING	FL	08/15/2001 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS	NATURAL GAS	180	MW	Sulfur Dioxide (SO2)	FUEL SPECIFICATIONS:: NATURAL GAS WITH A MAXIMUM OF 2.0 GRAINS OF SULFUR PER 100 SCF	0		0			BACT is fuel specification
FL-0252	FORT PIERCE REPOWERING	FL	08/15/2001 ACT	TURBINE, COMBINED CYCLE, FUEL OIL	FUEL OIL	180	MW	Sulfur Dioxide (SO2)	FUEL SPECIFICATIONS: DISTILLATE OIL, < 0 05% S BY WT	0		0			BACT is fuel specification
FL-0252	FORT PIERCE REPOWERING	FL	08/15/2001 ACT	DUCT BURNER, NATURAL GAS				Sulfur Dioxide (SO2)	CLEAN FUEL	0.2	LB/MMBTU	0.2	LB/MMBTU		
*FL-0330	PORT DOLPHIN ENERGY LLC	FL	12/01/2011 ACT	Boilers (4 - 278 mmbtu/hr each)	natural gas	0		Sulfur Dioxide (SO2)	use of natural gas	0.0006	LB/MMBTU	0			
*FL-0330	PORT DOLPHIN ENERGY LLC	FL	12/01/2011 ACT	Power Generator Engines (3)	natural gas	0		Sulfur Dioxide (SO2)	use of natural gas (99% of the time) and low sulfur fuel oil (1% of the time)	0.16	G/KW-H	0			
IA-0067	WALTER SCOTT JR. ENERGY CENTER	IA	06/17/2003 ACT	CBEC 4 BOILER	PRB COAL	7675	MMBTU/H	Sulfur Dioxide (SO2)	LIME SPRAY DRYER FLUE GAS DESULFURIZATION	0.1	LB/MMBTU	0.1	LB/MMBTU	30 DAY ROLLING AVERAGE	THE 30 DAY ROLLING AVERAGE BACT LIMIT DOES NOT INCLUDE STARTUP, SHUTDOWN, OR MALFUNCTION EMISSIONS. THE TON/YR LIMIT INCLUDES ALL EMISSIONS INCLUDING STARTUP, SHUTDOWN, AND MALFUNCTION.
IA-0067	WALTER SCOTT JR. ENERGY CENTER	IA	06/17/2003 ACT	AUXILIARY BOILER	NATURAL GAS	429.4	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES	0.0006	LB/MMBTU	0			
IA-0067	WALTER SCOTT JR. ENERGY CENTER	IA	06/17/2003 ACT	EMERGENCY GENERATOR	DIESEL FUEL	97.73	GAL/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES AND LOW SULFUR FUEL	0 052	LB/MMBTU	0			UNIT IS ALSO LIMITED TO FUEL WITH A MAXIMUM SULFUR CONTENT OF 0 05% (BY WT)
IA-0067	WALTER SCOTT JR. ENERGY CENTER	IA	06/17/2003 ACT	DIESEL FIRE PUMP	DIESEL FUEL	27.8	GAL/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES AND LOW SULFUR FUEL	0 052	LB/MMBTU	0			ALSO LIMITED TO FUEL WITH A MAXIMUM SULFUR CONTENT OF 0 05%
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	DDGS COOLER		140	T/H OF DRY FEED	Sulfur Dioxide (SO2)		10	PPMVD	0			SO2 OCCURS FROM THE USE OF WET MILL PROCESS WATER THAT IS LADEN WITH SO2.
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	INDIRECT-FIRED DDGS DRYER	NATURAL GAS	93.7	MMBTU/H	Sulfur Dioxide (SO2)		6	PPMVD	0			
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	GERM DRYERS AND COOLERS		15	T/H	Sulfur Dioxide (SO2)	WET SCRUBBER	10	PPMVD	0			SO2 OCCURS FROM THE USE OF WET MILL PROCESS WATER THAT IS LADEN WITH SO2.
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	FIRE PUMP	DIESEL #2	540	HP	Sulfur Dioxide (SO2)	BURN LOW-SULFUR DIESEL FUEL. 0.05% BY WEIGHT OR LESS NOT TO EXCEED THE NSPS REQUIREMENT.	0.17	G/B-HP-H	0			
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	WASTEWATER TREATMENT PLANT (WWTP) ANAEROBIC DIGESTER		1500	SCFM OF BIOGAS	Sulfur Dioxide (SO2)	LIMITED THE HYDROGEN SULFIDE CONCENTRATION OF THE BOIGAS PRODUCED TO 200 PPMV (24-HOUR ROLLING AVERAGE).	0 023	LB/MMBTU	0			

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IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	FERMENTATION, DISTILLATION AND DEHYDRATION		840000	GAL/H	Sulfur Dioxide (SO2)	CO2 SCRUBBER AND DISTILLATION NCG SCRUBBER	90	% REDUCTION	0			SO2 OCCURS FROM THE USE OF WET MILL PROCESS WATER THAT IS LADEN WITH SO2. THE CO2 SCRUBBER CONTROLS THE FERMENTATION TANKS, YEAST PROPAGATORS AND BEERWELLS. THE NCG SCRUBBER CONTROLS THE NITROGEN STRIPPER AND DISTILLATION COLUMN. THE PERCENT REDUCTION LIMIT APPLIES ACROSS BOTH OF THE SCRUBBER INDIVIDUALLY. THE CONCENTRATION LIMIT APPLIES TO THE OUTLET OF THE RTO, WHICH IS AFTER THE SCRUBBERS. THE LIMITS ARE WRITTEN AS 90 % REDUCTION OR 10 PPMV.
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	NATURAL GAS BOILER (292.5 MMBTU/H)	NATURAL GAS	292.5	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL ONLY	0.0006	LB/MMBTU	0			
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	EMERGENCY GENERATOR	DIESEL	1500	KW	Sulfur Dioxide (SO2)	BURN LOW-SULFUR DIESEL FUEL. 0.05% BY WEIGHT OR LESS NOT TO EXCEED THE NSPS REQUIREMENT.	0.17	G/B-HP-H	0			
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	ALCOHOL RAIL LOADOUT		12000	GAL/MIN	Sulfur Dioxide (SO2)	FUEL FIRED IN THE FLARE IS LIMITED TO NATURAL GAS AND BIOGAS	0.0025	LB/MMBTU	0			TON PER YEAR LIMIT IS THE SUM OF EMISSIONS FROM BOTH ALCOHOL LOADOUT FLARES AND CORRESPONDS TO A PLANTWIDE LOADOUT LIMIT OF 752,325,000 GALLONS OF ETHANOL PER 12-MONTH ROLLING PERIOD.
IN-0092	WHITING CLEAN ENERGY, INC.	IN	07/20/2000 ACT	TURBINES, COMBUSTION, NAT GAS (2) W/DUCT BURNER	NATURAL GAS	1735	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL. ALTERNATE LIMIT FOR EACH CT	6	LB/MMBTU	0			
IN-0092	WHITING CLEAN ENERGY, INC.	IN	07/20/2000 ACT	TURBINES, COMBUSTION, NATURAL GAS (2)	NATURAL GAS	1735	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES AND LOW SULFUR FUEL (0 8 % BY WT SULFUR). PERMIT LIMITS TOTAL SO2 FROM COMBUSTION TURBINES AND DUCT BURNERS TO 22 8 LB/H.	150	PPM @ 15% O2	150	PPM @ 15% O2		
IN-0092	WHITING CLEAN ENERGY, INC.	IN	07/20/2000 ACT	GENERATORS, STEAM, NATURAL GAS (2) W/DUCT BURNERS	NATURAL GAS	821	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL.	0.2	LB/MMBTU	0.2	LB/MMBTU		
IN-0114	MIRANT SUGAR CREEK LLC	IN	07/24/2002 ACT	DUCT BURNER, NATURAL GAS, (4)	NATURAL GAS	300	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR NATURAL GAS: < 007% S BY WT (2 GR/100 SCF), GOOD COMBUSTION PRACTICE.	0 001	LB/MMBTU	0.001	LB/MMBTU		
IN-0114	MIRANT SUGAR CREEK LLC	IN	07/24/2002 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS (4)	NATURAL GAS	1490.5	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR NATURAL GAS: 0 007 % S BY WT (2 GR/100 SCF), GOOD COMBUSTION PRACTICE	0.0028	LB/MMBTU	0			
IN-0114	MIRANT SUGAR CREEK LLC	IN	07/24/2002 ACT	TURBINES, SIMPLE CYCLE, NATURAL GAS, (4)	NATURAL GAS	1490.5	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR NATURAL GAS: < 0.007 % S BY WT (2 GR/100 SCF), GOOD COMBUSTION PRACTICES.	0.0028	LB/MMBTU	0			
IN-0114	MIRANT SUGAR CREEK LLC	IN	07/24/2002 ACT	TURBINE, COMBINED CYCLE AND DUCT BURNER, NAT GAS	NATURAL GAS	1490.5	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR NATURAL GAS: < .007 %S BY WT (2 GR/100 SCF), GOOD COMBUSTION PRACTICE.	4.4	LB/H	0			

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*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	SYNGAS HYDROCARBON FLARE	SYNGAS	0 27	MMBTU/H	Sulfur Dioxide (SO2)	A FLARE MINIMIZATION PLAN	0		0			IDENTIFIED AS (EU-001) SHALL BE LIMITED AS FOLLOWS: A. THE PERMITTEE SHALL COMPLY WITH THE FOLLOWING FLARE MINIMIZATION PLAN TO REDUCE SO2 EMISSIONS DURING STARTUPS, SHUTDOWNS, AND OTHER FLARING EVENTS. THE PERMITTEE WILL USE METHANOL, RATHER THAN COAL OR PET COKE, AS THE FEEDSTOCK IN EACH GASIFIER DURING STARTUP CONDITIONS REQUIRING SYNGAS FLARING, THEREBY REDUCING EMISSIONS OF SULFUR DIOXIDE AT THE SYNGAS HYDROCARBON FLARE. DURING A PLANNED SHUTDOWN OF A GASIFIER, THE PERMITTEE SHALL ROUTE THE CONTENTS OF EACH GASIFIER UNIT (GASIFIER VESSEL, QUENCH CHAMBER, SCRUBBER VESSEL) DURING INITIAL DEPRESSURIZATION TO ONE OF THE WET SULFURIC ACID (WSA) PLANTS. THE PERMITTEE SHALL REDUCE GASIFIER FEED RATES SUCH THAT ALL SYNGAS CAN BE PROCESSED THROUGH ONE GAS TREATMENT TRAIN PRIOR TO A SCHEDULED GAS TREATMENT TRAIN OUTAGE. THIS LIMITS THE AMOUNT OF SYNGAS THAT WILL HAVE TO BE SENT TO THE SYNGAS HYDROCARBON FLARE. THE PERMITTEE SHALL HAVE WRITTEN PROCEDURES FOR THE ABOVE OPERATIONS AND THE PERMITTEE SHALL TRAIN THE OPERATORS ON THESE PROCEDURES.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	ACID GAS FLARE	ACID GAS	0 27	MMBTU	Sulfur Dioxide (SO2)	FLARE MINIMIZATION PLAN	0		0			EMISSION LIMITS: NONE (3) THE SO2 EMISSIONS FROM THE ACID GAS FLARE, IDENTIFIED AS (EU-002) SHALL BE LIMITED AS FOLLOWS: A. THE PERMITTEE SHALL COMPLY WITH THE FOLLOWING FLARE MINIMIZATION PLAN TO REDUCE EMISSIONS DURING FLARING EVENTS. THE PERMITTEE SHALL INVESTIGATE THE ?ROOT CAUSE? OF MALFUNCTION EVENTS THAT CAUSE GASES TO BE SENT TO A FLARE AND DETERMINE WHETHER THERE ARE ADDITIONAL PREVENTATIVE MEASURES THAT CAN BE IMPLEMENTED TO MINIMIZE RE-OCCURRENCE OF THESE EVENTS. SUCH IDENTIFIED MEASURES SHALL BE IMPLEMENTED AND DOCUMENTED.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	TWO (2) AUXILIARY BOILERS	NATURAL GAS	408	MMBTU/H, EACH	Sulfur Dioxide (SO2)	USE OF NATURAL GAS OR SNG	0.0006	MMBTU/H	0			
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	REGENERATIVE THERMAL OXIDIZER (RTO) ON THE ACID GAS REMOVAL UNIT VENTS (AGR)	NATURAL GAS	38.8	MMBTU/H, EACH	Sulfur Dioxide (SO2)	RECTISOL ACID GAS REMOVAL SYSTEM	3.17	LB/H	0			EMISSION LIMIT 1 IS FOR EACH RTO.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	FIVE (5) GASIFIER PREHEAT BURNERS	NATURAL GAS AND SNG	35	MMBTU/H, EACH	Sulfur Dioxide (SO2)	USE OF CLEAN BURNING GASEOUS FUEL	0.0006	LB/MMBTU	0			EMISSION LIMIT IS FOR EACH BURNER.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	TWO (2) EMERGENCY GENERATORS	DIESEL	1341	HORSEPOWER, EACH	Sulfur Dioxide (SO2)	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION	15	PPM SULFUR	0			EMISSION LIMIT: EACH EMERGENCY GENERATOR SHALL NOT EXCEED 52 HOURS PER YEAR OF NONEMERGENCY OPERATION.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	THREE (3) FIREWATER PUMP ENGINES	DIESEL	575	HORSEPOWER, EACH	Sulfur Dioxide (SO2)	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION	15	PPM SULFUR	0			EMISSION LIMITS: EACH EMERGENCY GENERATOR SHALL NOT EXCEED 52 HOURS PER YEAR OF NONEMERGENCY OPERATION.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	TWO (2) WET SULFURIC ACID PLANTS	STPD	800	STPD	Sulfur Dioxide (SO2)	PEROXIDE SCRUBBER	0.25	LB/T ACID PRODUCED	0			EMISSION LIMIT IS FOR EACH UNIT.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	ZLD SPRAY DRYER		5.6	MMBTU/H	Sulfur Dioxide (SO2)	USE OF A CLEAN BURNING GASEOUS FUEL	0		0			
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	FUGITIVE LEAKS FROM PIPING		0		Sulfur Dioxide (SO2)	LEAK DETECTION AND REPAIR (LDAR) PROGRAM	0		0			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	SPACE HEATERS	NATURAL GAS	1	MMBTU/H EACH	Sulfur Dioxide (SO2)	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0005	LB/MMBTU	0			LIMIT IS FOR EACH HEATER
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	COKE BREEZE ADDITIVE SYSTEM AIR HEATER	NATURAL GAS	1.7	MMBTU/H	Sulfur Dioxide (SO2)	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0005	LB/MMBTU	0			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	EMERGENCY GENERATOR	NATURAL GAS	620	HP	Sulfur Dioxide (SO2)	USE OF NATRUAL GAS AND GOOD COMBUSTION PRACTICES	0.0015	G/KW-H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas > 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	FIRE WATER PUMP	NATURAL GAS	300	HP	Sulfur Dioxide (SO2)	USE OF NATUAL GAS AND GOOD COMBUSTION PRACTICES	0.0015	G/KW-H	0			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	COKE BREEZE ADDITIVE SYSTEM		16.5	T/H	Sulfur Dioxide (SO2)		0.0005	LB/MMBTU	0			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	GROUND LIMESTONE/DOLOMITE ADDITIVE SYSTEM AIR HEATER	NATURAL GAS	19	MMBTU/H	Sulfur Dioxide (SO2)	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0005	LB/MMBTU	0			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	FURNACE HOOD EXHAUST	NATURAL GAS	436	MMBTU/H	Sulfur Dioxide (SO2)		21.68	LB/H	0			LIMIT ONE: 7.1 PPMV WET AT 20% O2 NOTE: 0.089 LB SO2/TON PELLETS * 450 TONS/HR = 40.1 LB/HR SO2
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	FURNACE WINDBOX EXHAUST (WBE)	NATURAL	436	MMBTU/H	Sulfur Dioxide (SO2)	GSA DRY SCRUBBER AND BAGHOUSE CE016	19.61	LB/H	0			LIMIT ONE: 5.0 PPMV WET AT 15% O2 NOTE: 0.048 LB SO2/TON PELLETS * 450 TONS/HR = 21.6 LB/HR SO2
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	TOWEL MACHINE NO. 6 TAD EXHAUST 2	NATURAL GAS	306	T/D	Sulfur Dioxide (SO2)	NATURAL GAS AS FUEL	0.04	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	TOWEL MACHINE NO. 6 YANKEE AIRCAP EXHAUST		306	T/D	Sulfur Dioxide (SO2)	NATURAL GAS AS FUEL	0.02	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 1		2 81	MM LB/D	Sulfur Dioxide (SO2)		105.91	LB/H	0			ADDITIONAL EMISSION LIMIT: 120 PPMV @ 8% O2.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	TOWEL MACHINE NO. 6 TAD EXHAUST 1	NATURAL GAS	306	T/D	Sulfur Dioxide (SO2)	NATURAL GAS AS FUEL	0.07	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 2		3 96	MM LB/D	Sulfur Dioxide (SO2)		143.23	LB/H	0			ADDITIONAL EMISSION LIMIT: 120 PPMV AT 8% O2.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	SMELT TANK NO. 1		3 32	MM LB BLS/D	Sulfur Dioxide (SO2)	WET SCRUBBER	9.22	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	SMELT TANK NO. 2		2 25	MM LB BLS/D	Sulfur Dioxide (SO2)	WET SCRUBBERS	6.24	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	LIME KILN NO. 1		340	T/D	Sulfur Dioxide (SO2)	WET SCRUBBERS AND OPTIMAL MUD WASHING	3.26	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	LIME KILN NO. 2		270	T/D	Sulfur Dioxide (SO2)	WET SCRUBBERS AND OPTIMAL MUD WASHING	2.59	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	POWER BOILER NO. 5	NATURAL GAS	987	MMBTU/H	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS	5126	LB/H	5.19	LB/MMBTU		
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	POWER BOILER NO. 2	NAT GAS	65.5	MMBTU/H	Sulfur Dioxide (SO2)	FIRING NATURAL GAS	0.26	LB/H	0.004	LB/MMBTU		
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	COMBINATION BOILER NO. 1	WOOD WASTE / NAT GAS	459.5	MMBTU/H	Sulfur Dioxide (SO2)	ADD-ON: WET SCRUBBER. P2: FUEL CAN BE EITHER WOOD WASTE OR NATURAL GAS.	37.37	LB/H	0.73	LB/MMBTU		
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	GAS TURBINES - 187 MW (2)		2006	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR NATURAL GAS, 1.8 GRAINS PER 100 SCF	10.1	LB/H	0			
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	FUEL GAS HEATERS (3)		19	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR PIPELINE NATURAL GAS AND GOOD COMBUSTION PRACTICES	0 008	LB/H	0.0004	LB/MMBTU	ANNUAL AVERAGE	*TPY LIMIT FOR ALL 3 HEATERS. AGGREGATE HEAT INPUT IS LIMITED TO 14,250 MM BTU/YR. ONLY 2 OF THE 3 HEATERS ARE ALLOWED TO OPERATE AT ANY GIVEN TIME.
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	DIESEL FIRED WATER PUMP				Sulfur Dioxide (SO2)	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES	0.61	LB/H	0.65	G/B-HP-H	ANNUAL AVERAGE	OPERATING TIME = 52 HR/YR
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	DUCT BURNERS (2)		759	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR NATURAL GAS, 1.8 GRAINS PER 100 SCF	3.8	LB/H	0.005	LB/MMBTU	ANNUAL AVERAGE	
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	SHIFT REACTOR STARTUP HEATER	NATURAL GAS	34.2	MMBTU/H	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR SUBSTITUTE NATURAL GAS (SNG)	0.02	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	GASIFIER STARTUP PREHEATER BURNERS (5)	NATURAL GAS	35	MMBTU/H	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR SUBSTITUTE NATURAL GAS (SNG)	0.02	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	ACID GAS FLARE	NATURAL GAS	0 27	MMBTU/H	Sulfur Dioxide (SO2)	NO ADDITIONAL CONTROL	0.01	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	FIRE WATER DIESEL PUMPS (3)	DIESEL	575	HP EACH	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART IIII	0.01	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	HYDROCARBON/GASIFIERS STARTUP FLARE	NATURAL GAS	487 55	MMBTU/H	Sulfur Dioxide (SO2)	NO ADDITIONAL CONTROL	1303.99	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	METHANATION STARTUP HEATERS	NATURAL GAS	56.9	MMBTU/H	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR SUBSTITUTE NATURAL GAS (SNG)	0.03	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	AUXILIARY BOILER	NATURAL GAS	938.3	MMBTU/H	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR SUBSTITUTE NATURAL GAS (SNG)	0.28	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	THERMAL OXIDIZERS (2)	NATURAL GAS	40.9	MMBTU/H	Sulfur Dioxide (SO2)	NO ADDITIONAL CONTROL	22.92	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	EMERGENCY DIESEL POWER GENERATOR ENGINES (2)	DIESEL	1341	HP EACH	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART IIII	0.01	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	WET SULFURIC ACID PLANTS (2)		2000	T/D	Sulfur Dioxide (SO2)	HYDROGEN PEROXIDE SCRUBBERS	13.8	LB/H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas > 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
LA-0238	ALLIANCE REFINERY	LA	07/10/2009 ACT	FCCU FEED HEATER	REFINERY GAS	181.7	MMBTU/H	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART J	4.79	LB/H	0			
LA-0238	ALLIANCE REFINERY	LA	07/10/2009 ACT	CO BOILERS (2)	REFINERY GAS	831.3	MMBTU/H EACH	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART J	1286	LB/H	0			
LA-0238	ALLIANCE REFINERY	LA	07/10/2009 ACT	FCCU REGEN VENT - SU/SD OPERATIONS		89000	BBL/D	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART J	1286	LB/H	0			
LA-0245	HYDROGEN PLANT	LA	12/15/2010 ACT	SMR Heaters (EQT0400 and EQT0401)	Fuel Gas	1055	MMBTU/H	Sulfur Dioxide (SO2)	Limit maximum H2S concentration in fuels to 60 ppmv (annual average)	16.7	LB/H	0			
LA-0248	DIRECT REDUCTION IRON PLANT	LA	01/27/2011 ACT	DRI-111 - DRI Unit #1 Acid Gas Absorption Vent		30624	scfm	Sulfur Dioxide (SO2)	BACT is selected to be treatment of the acid gas stream through the use of a sulfur redox catalyst, such as the SulfaTreat catalyst bed or LO-CAT Redox process, for the removal of H2S. Nucor will install a redox catalyst on each of the acid gas absorption vents at the DRI facility for the control of sulfur compound emissions.	0.58	LB/H	0			The acid gas absorber selectively removes acid gases such as hydrogen sulfide and carbon dioxide from the top gas fuel, prior to combustion at the reformer. The amine-based absorption medium is then regenerated by the application of heat, releasing the absorbed acid gases as a separate gas stream. The efficiency of the DRI process benefits from the removal of these gases, which are no longer heated during combustion. The energy saved from no longer heating inert gases in the top gas fuel is then available for the reforming reaction. An added benefit is the isolation of hydrogen sulfide, which can then be treated more effectively.
LA-0248	DIRECT REDUCTION IRON PLANT	LA	01/27/2011 ACT	DRI-211 - DRI Unit #1 Acid Gas Absorption Vent		30624	scfm	Sulfur Dioxide (SO2)		0.58	LB/H	0			The acid gas absorber selectively removes acid gases such as hydrogen sulfide and carbon dioxide from the top gas fuel, prior to combustion at the reformer. The amine-based absorption medium is then regenerated by the application of heat, releasing the absorbed acid gases as a separate gas stream. The efficiency of the DRI process benefits from the removal of these gases, which are no longer heated during combustion. The energy saved from no longer heating inert gases in the top gas fuel is then available for the reforming reaction. An added benefit is the isolation of hydrogen sulfide, which can then be treated more effectively. BACT is selected to be treatment of the acid gas stream through the use of a sulfur redox catalyst, such as the SulfaTreat catalyst bed or LO-CAT Redox process, for the removal of H2S. Nucor will install a redox catalyst on each of the acid gas absorption vents at the DRI facility for the control of sulfur compound emissions.
LA-0248	DIRECT REDUCTION IRON PLANT	LA	01/27/2011 ACT	DRI-106 - DRI Unit No. 1 Upper Seal Gas Vent		1765	acfm	Sulfur Dioxide (SO2)		0.02	LB/H	0			Sulfur dioxide BACT was determined to treat the spent reducing gas being sent to the Reformer as combustion fuel. The seal gas is removed before the spent reducing gas is treated for SO2 control, and so no additional control is feasible for the seal gas.
LA-0248	DIRECT REDUCTION IRON PLANT	LA	01/27/2011 ACT	DRI-206 - DRI Unit No. 2 Upper Seal Gas Vent		1765	acfm	Sulfur Dioxide (SO2)		0.02	LB/H	0			Sulfur dioxide BACT was determined to treat the spent reducing gas being sent to the Reformer as combustion fuel. The seal gas is removed before the spent reducing gas is treated for SO2 control, and so no additional control is feasible for the seal gas.
LA-0248	DIRECT REDUCTION IRON PLANT	LA	01/27/2011 ACT	DRI-108 - DRI Unit #1 Reformer Main Flue Stack	Iron Ore and Natural Gas	12168	Billion Btu/yr	Sulfur Dioxide (SO2)	BACT is selected to be the removal of hydrogen sulfide from the top gas fuel through acid gas scrubbing. This technology was identified as the most stringent control method of the available technologies, and has the added benefit of slightly reducing energy demand at the reformer. Nucor will install and acid gas scrubbing system for top gas prior to its use as fuel in the reformer. BACT for natural gas is to purchase natural gas containing no more than 2000 grains of Sulfur per MM scf.	3.16	LB/H	0.002	LB/MMBTU		Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources. Emissions of SO2 are usually attributable to the sulfur contained within the fuel being combusted. Therefore the use of a low sulfur fuel can drastically reduce emissions of SO2 when compared to other potential fuels. Sweet natural gas is often cited as an alternative to other fuels due to the very low sulfur content of this fuel The reformer also burns top gas from the shaft furnace, which contains a small portion of hydrogen sulfide originating from sulfur compounds in the iron ore, as well as any sulfur that was in the natural gas converted into reformer gas. Once combusted, this hydrogen sulfide converts directly to SO2. Because sulfur is rarely introduced into a combustion reaction other than as a component of the fuel, Nucor evaluated both fuel treatment for the removal of hydrogen sulfide and other sulfur compounds, as well as flue gas desulfurization (FGD) for the removal of SO2 from the products of combustion in the flue gas.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas > 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
LA-0248	DIRECT REDUCTION IRON PLANT	LA	01/27/2011 ACT	DRI-208 - DRI Unit #2 Reformer Main Flue Stack	Iron ore and Natural Gas	12168	Billion Btu/yr	Sulfur Dioxide (SO2)	BACT is selected to be the removal of hydrogen sulfide from the top gas fuel through acid gas scrubbing. This technology was identified as the most stringent control method of the available technologies, and has the added benefit of slightly reducing energy demand at the reformer. Nucor will install and acid gas scrubbing system for top gas prior to its use as fuel in the reformer. BACT for natural gas is to purchase natural gas containing no more than 2000 grains of Sulfur per MM scf.	3.16	LB/H	0.002	LB/MMBTU		Method 8 - Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources. Emissions of SO2 are usually attributable to the sulfur contained within the fuel being combusted. Therefore the use of a low sulfur fuel can drastically reduce emissions of SO2 when compared to other potential fuels. Sweet natural gas is often cited as an alternative to other fuels due to the very low sulfur content of this fuel The reformer also burns top gas from the shaft furnace, which contains a small portion of hydrogen sulfide originating from sulfur compounds in the iron ore, as well as any sulfur that was in the natural gas converted into reformer gas. Once combusted, this hydrogen sulfide converts directly to SO2. Because sulfur is rarely introduced into a combustion reaction other than as a component of the fuel, Nucor evaluated both fuel treatment for the removal of hydrogen sulfide and other sulfur compounds, as well as flue gas desulfurization (FGD) for the removal of SO2 from the products of combustion in the flue gas.
LA-0248	DIRECT REDUCTION IRON PLANT	LA	01/27/2011 ACT	DRI-109 - DRI Unit #1 Package Boiler Flue Stack	Natural Gas	1760	Billion Btu/yr	Sulfur Dioxide (SO2)	Emissions of SO2 are usually attributable to the sulfur contained within the fuel being combusted. Therefore the use of a low sulfur fuel can drastically reduce emissions of SO2 when compared to other potential fuels.	0.09	LB/H	0			Sulfur dioxide: Purchase natural gas with a sulfur content less than 2000 grains per million standard cubic feet of gas. Sulfur content shall be monitored and recorded monthly and shall be based on either the natural gas analysis provided by the supplier or direct sampling by the facility
LA-0248	DIRECT REDUCTION IRON PLANT	LA	01/27/2011 ACT	DRI-209 - DRI Unit #2 Package Boiler Flue Stack	Natural Gas	1760	Billion Btu/yr	Sulfur Dioxide (SO2)	Emissions of SO2 are usually attributable to the sulfur contained within the fuel being combusted. Therefore the use of a low sulfur fuel can drastically reduce emissions of SO2 when compared to other potential fuels.	0.09	LB/H	0			Sulfur dioxide: Purchase natural gas with a sulfur content less than 2000 grains per million standard cubic feet of gas. Sulfur content shall be monitored and recorded monthly and shall be based on either the natural gas analysis provided by the supplier or direct sampling by the facility
MD-0031	CHALK POINT	MD	04/01/2005 ACT	GE 7EA COMBUSTION TURBINE - NG, SC ONLY	NATURAL GAS	85	MW	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUELS	6.3	LB/H	0			EMISSIONS LIMITS APPLY TO EACH CT WHEN FIRING NATURAL GAS AND OPPORATING IN SIMPLE CYCLE MODE
MD-0031	CHALK POINT	MD	04/01/2005 ACT	(2) NATURAL GAS FUEL HEATERS	NATURAL GAS	10	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUELS	0 056	LB/H	0		NOT AVAILABLE	OPERATION OF EACH HEATER SHALL NOT EXCEED 1500 HR/12-MONTH PERIOD
MD-0031	CHALK POINT	MD	04/01/2005 ACT	GE 7EA COMBUSTION TURBINE - FO, SC ONLY		85	MW	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUELS	60.3	LB/H	0			EMISSION LIMIT APPLIES TO EACH CT WHEN FIRING FUEL OIL AND OPPERATING IN SIMPLE CYCLE MODE
MD-0032	DICKERSON	MD	11/05/2004 EST	UNIT 4 -GE FRAME 7F COMB. TURBINES W/ HRSG - NG CC	NATURAL GAS	196	MW	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUELS	11	LB/H	0			LIMIT APPLIES TO UNIT 4 WITH FIRING NG WITH OR WITH OUT DUCT FIRING AND OPPORATING IN COMBINED CYCLE MODE
MD-0032	DICKERSON	MD	11/05/2004 EST	UNIT 4 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO CC		196	MW	Sulfur Dioxide (SO2)		92	LB/H	0			LIMIT APPLIES TO UNIT 4 WHEN FIRING 0.05 WT% SULFUR FUEL OIL WITH OUT DUCT FIRING AND OPPORATING IN EITHER COMBINED OR SIMPLE CYCLE MODE, FIRING LIMITED TO 250 H/YR IN SIMPLE CYCLE AND 720 H/YR IN COMBINED CYCLE MODE
MD-0032	DICKERSON	MD	11/05/2004 EST	UNIT 4 -GE FRAME 7F COM. TURBINES W/ HRSG - NG SC	NATURAL GAS	196	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	11	LB/H	0			LIMIT APPLIES TO UNIT 4 FIRING NG WITH OUT DUCT FIRING AND OPPORATING IN SIMPLE CYCLE MODE
MD-0032	DICKERSON	MD	11/05/2004 EST	UNIT 5 -GE FRAME 7F COMB. TURBINES W/ HRSG- FO CC		196	MW	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL	106	LB/H	0			LIMIT APPLIES TO UNIT 5 WHEN FIRING 0.05 WT% SULFUR FUEL OIL WITH OUT DUCT FIRING AND OPPORATING IN EITHER COMBINED OR SIMPLE CYCLE MODE, FIRING LIMITED TO 250 H/YR IN SIMPLE CYCLE AND 720 H/YR IN COMBINED CYCLE MODE
MD-0032	DICKERSON	MD	11/05/2004 EST	UNIT 5 -GE FRAME 7F COM. TURBINES W/ HRSG - NG SC		196	MW	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUELS	12	LB/H	0			LIMIT APPLIES TO UNIT 4 FIRING NG WITH OUT DUCT FIRING AND OPPORATING IN SIMPLE CYCLE MODE
MD-0032	DICKERSON	MD	11/05/2004 EST	AUXILARY BOILER - NG		60	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES, USE OF CLEAN FUEL	0.34	LB/H	0 01	LB/MMBTU	CALCULATED	EMISSION LIMIT APPLIES TO AUXILARY BOILER WHEN FIRING NATURAL GAS
MD-0032	DICKERSON	MD	11/05/2004 EST	AUXILARY BOILER - FO	NATURAL GAS	60	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE, USE OF CLEAN FUELS	3.1	LB/H	0 05	LB/MMBTU	CALCULATED	EMISSION LIMIT APPLIES TO AUXILARY BOILER WHEN FIRING FUEL OIL
MD-0032	DICKERSON	MD	11/05/2004 EST	UNIT 5 -GE FRAME 7F COMB. TURBINES W/ HRSG - NG CC	NATURAL GAS	196	MW	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUELS	12	LB/H	0			LIMIT APPLIES TO UNIT 5 WITH FIRING NG WITH OR WITH OUT DUCT FIRING AND OPPORATING IN COMBINED CYCLE MODE
MI-0357	KALKASKA GENERATING, INC	MI	02/04/2003 ACT	DUCT BURNERS ON HRSGS, (2)	NATURAL GAS	620	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL.	0 003	LB/MMBTU	0.003	LB/MMBTU		Emissions are from each duct burner.
MN-0048	BLACK DOG GENERATING PLANT	MN	01/12/2001 ACT	TURBINE, COMBINED CYCLE	NATURAL GAS	290	MW	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL LIMITED TO 0 004 GR/DSCF, USING 12-MONTH ROLLING AVG.	0		0			
MN-0048	BLACK DOG GENERATING PLANT	MN	01/12/2001 ACT	DUCT FIRING BURNERS	NATURAL GAS	510	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL-PIPELINE QUALITY NATURAL GAS; SULFUR CONTENT OF FUEL LESS THAN 0 004 GR/DSCF USING 12-MO ROLLING AV; PRIMARY EMISSION LIMIT 30 D ROLLING AV	0.2	LB/MMBTU	0.2	LB/MMBTU		

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas > 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	INTERNAL COMBUSTION ENGINE, LARGE	DIESEL FUEL	1850	HP	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.59	G/B-HP-H	0			
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	INTERNAL COMBUSTION ENGINE, SMALL	DIESEL FUEL	290	HP	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.14	G/B-HP-H	0			
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	COMBUSTION TURBINE, LARGE 2 EACH	NATURAL GAS	1827	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFLUR FUEL	0.05	% S BY WT	0			LIMIT APPLIES TO OIL SULFUR CONENT
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	DUCT BURNER, 2 EACH	NATURAL GAS	800	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.8	GR/100SCF	0		NOT AVAILABLE	LIMIT IS FOR SULFUR CONTENT OF NG
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	COMBUSTION TURBINE, LARGE, 2 EACH	NATURAL GAS	1916	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.8	GR/100SCF	0			LIMIT IS FOR SULFUR CONENT OF NG
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	BOILER, COMMERCIAL	NATURAL GAS	70	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0 001	LB/MMBTU	0.001	LB/MMBTU		
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007 ACT	TUNNEL FURNACE	NATURAL GAS	205	T/H	Sulfur Dioxide (SO2)		1	PPM	0			
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007 ACT	INDURATING FURNACE - WASTE GAS	NATURAL GAS	624	T/H	Sulfur Dioxide (SO2)	WET SCRUBBER	3.3	PPM@15%02	0			
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007 ACT	PROCESS HEATERS	NATURAL GAS	606	MMBTU/H	Sulfur Dioxide (SO2)	LIMITED TO NATURAL GAS	0.0029	LB/T	0			
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007 ACT	ELECTRIC ARC FURNACE/MELT SHOP		205	T/H	Sulfur Dioxide (SO2)		0.15	LB/T	0			
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007 ACT	INDURATING FURNACE - HOOD EXHAUST	NATURAL GAS	624	SHORT T/H	Sulfur Dioxide (SO2)	WET SCRUBBER	7.8	PPM@15%02	0			
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007 ACT	DIESEL FIRE WATER PUMPS (<500 HP)				Sulfur Dioxide (SO2)	LIMITED SULFUR IN FUEL; LIMITED HOURS	0.05	%	0			LIMITED TO 500 HOURS PER YEAR (12 MONTH ROLLING SUM) SULFUR CONTENT OF FUEL SO2 EMISSIONS
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	MN	09/07/2007 ACT	EMERGENCY POWER GENERATION - DIESEL	DIESEL			Sulfur Dioxide (SO2)	LIMITED HOURS, LIMITED SULFUR IN FUEL	0.05	%	0			LIMITED TO 500 HOURS PER YEAR (12 MONTH ROLLING AVERAGE); SULFUR LIMIT FOR FUEL LIMITS SO2 EMISSIONS.
MS-0075	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	07/09/2003 ACT	SMELT DISSOLVING TANKS (4)	NA	36.5	T BLS/H, each tank	Sulfur Dioxide (SO2)	SCRUBBERS ON EACH TANK	6.5	LB/H	0			ALSO, 0.2 LB/T AIR-DRIED PULP
MS-0075	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	07/09/2003 ACT	LIME KILN	NATURAL GAS	200	MMBTU/H	Sulfur Dioxide (SO2)	SCRUBBER	12.4	LB/H	0			
MS-0075	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	07/09/2003 ACT	NCG THERMAL OXIDIZER (BACK-UP)	NATURAL GAS	7.5	MMBTU/H	Sulfur Dioxide (SO2)	SCRUBBER	0 045	LB/H	0.006	LB/MMBTU	CALCULATED	
MS-0075	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	07/09/2003 ACT	RECOVERY BOILER NO. 1	BLACK LIQUOR	861.4	MMBTU/H	Sulfur Dioxide (SO2)		408.33	LB/H	0			7.0 LBS SO2 / TON AIR-DRIED PULP
MS-0075	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	07/09/2003 ACT	COMBINATION BOILER	SCRAP WOOD	917.4	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR LIMIT ON FUELS BURNED. SEE NOTE	2335.5	LB/H	0 26	LB/MMBTU		DISCONTINUATION OF NO. 6 FUEL OIL. MAXIMUM OF 1% SULFUR CONTENT IN THE USED OIL BURNED. MAXIMUM USEAGE RATE FOR THE VOLUME OF ON-SITE GENERATED USED OIL THAT CAN BE BURNED.
MS-0075	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	07/09/2003 ACT	POWER BOILER - NG	NATURAL GAS	766	MMBTU/H	Sulfur Dioxide (SO2)		0.46	LB/H	0.0006	LB/MMBTU		
MS-0075	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	07/09/2003 ACT	RECOVERY BOILER NO. 2	BLACK LIQUOR	861.4	MMBTU/H	Sulfur Dioxide (SO2)		408.33	LB/H	0			7 LB SO2 / T AIR-DRIED PULP.
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	LADLE PREHEATER	NATURAL GAS	48	MMBTU/H	Sulfur Dioxide (SO2)		346.59	LB/T	0			
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	NNI REHEAT FURNACE	NATURAL GAS	133	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	NNII REHEAT FURNACE	NATURAL GAS	143	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	NNII BILET POST-HEATER	NATURAL GAS	6.8	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	CUT-OFF TORCHES	NATURAL GAS			Sulfur Dioxide (SO2)		2.25	LB/T	0			
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	AUXILIARY BOILER	NATURAL GAS	200	MMBTU/H	Sulfur Dioxide (SO2)	NONE	0.8	LB/H	0.004	LB/MMBTU		BASIS OF LIMIT IS STATE.
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	DUCT BURNER (3)	NATURAL GAS	256	MMBTU/H	Sulfur Dioxide (SO2)	NONE LISTED	0.2	LB/MMBTU	0.2	LB/MMBTU		
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	COMBINED CYCLE TURBINE WITH DUCT BURNER	NATURAL GAS	3202	MMBTU/H	Sulfur Dioxide (SO2)	NONE LISTED	0 004	LB/MMBTU	0.8	PPM @ 15% O2		
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	EMERGENCY GENERATOR	DISTILLATE OIL	14.1	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR IN OIL LIMITED TO 0.05% BY WEIGHT.	0.8	LB/H	0			
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	COMBINED CYCLE TURBINE (3)	NATURAL GAS	2964	MMBTU/H	Sulfur Dioxide (SO2)	ONLY USE NATURAL GAS WITH SULFUR CONTENT 0.8%	0 004	LB/MMBTU	0.8	PPM @ 15% O2		BASIS OF LIMIT IS STATE
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	DIESEL FIRE PUMP	DISTILLATE OIL	3.5	MMBTU/H	Sulfur Dioxide (SO2)	NONE	1	LB/H	0			
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	08/20/2009 ACT	BOILER - UNIT HA08	NATURAL GAS	8 37	MMBTU/H	Sulfur Dioxide (SO2)	FUEL IS LIMITED TO NATURAL GAS.	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	BOILERS - UNITS CC001, CC002, AND CC003 AT CITY CENTER	NATURAL GAS	41.64	MMBTU/H	Sulfur Dioxide (SO2)	LIMITING THE FUEL TO NATURAL GAS ONLY.	0.0007	LB/MMBTU	0.0007	LB/MMBTU		EMISSION LIMIT 2 APPLIES TO EACH OF THE THREE UNITS.

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NY-0086	RAVENSWOOD GENERATING STATION	NY	09/07/2001 ACT	TURBINE WITHOUT DUCT BURNER (NATURAL GAS)	NATURAL GAS	250	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL- .04%	0.0071	LB/MMBTU	0			
NY-0086	RAVENSWOOD GENERATING STATION	NY	09/07/2001 ACT	TURBINE WITHOUT DUCT BURNER (KEROSENE)	KEROSENE	250	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL (0.04%)	0 044	LB/MMBTU	0			
NY-0086	RAVENSWOOD GENERATING STATION	NY	09/07/2001 ACT	DUCT BURNER	NATURAL GAS	644	MMBTU/H (HHV)	Sulfur Dioxide (SO2)	LOW SULFUR FUEL (0.04%)	0.0071	LB/MMBTU	0			
OH-0269	BIOMASS ENERGY, LLC-SOUTH POINT POWER	OH	01/05/2004 ACT	AUXILIARY BOILER, FUEL OIL	FUEL OIL #2	227	MMBTU/H	Sulfur Dioxide (SO2)		2.84	LB/H	0.0125	LB/MMBTU	CALCULATED	ADDITIONAL LIMITS FOR FUEL OIL: 0.50% BY WEIGHT. 0.33 T/YR IS TOTAL FOR AUXILIARY BOILER, ALL FUELS
OH-0269	BIOMASS ENERGY, LLC-SOUTH POINT POWER	OH	01/05/2004 ACT	AUXILIARY BOILER, NATURAL GAS	NATURAL GAS	247	MMBTU/H	Sulfur Dioxide (SO2)		0.15	LB/H	0.6	LB/MMBTU	WITH NATURAL GAS	LIMITS ARE FOR NATURAL GAS, EXCEPT: 0.33 T/YR IS TOTAL FOR AUXILIARY BOILER, ALL FUELS
OH-0269	BIOMASS ENERGY, LLC-SOUTH POINT POWER	OH	01/05/2004 ACT	WOOD FIRED BOILERS (7)	WOOD	175	MMBTU/H	Sulfur Dioxide (SO2)	DRY SODIUM BICARBONATE INJECTION SYSTEM OR SPRAY DRYER ADSORBER	22.13	LB/H	0.087	LB/MMBTU		LIMITS ARE FOR EACH OF 7 BOILERS
OH-0307	SOUTH POINT BIOMASS GENERATION	OH	04/04/2006 ACT	WOOD FIRED BOILERS (7)	WOOD	318	MMBTU/H	Sulfur Dioxide (SO2)	SPRAY DRYER ADSORBER OR DRY SODIUM BICARBONATE INJECTION SYSTEM	22.13	LB/H	0.087	LB/MMBTU	FACILITY FACTOR	LIMITS ARE FOR EACH OF THE 7 BOILERS.
OH-0307	SOUTH POINT BIOMASS GENERATION	OH	04/04/2006 ACT	AUXILIARY BOILER	NATURAL GAS	247	MMBTU/H	Sulfur Dioxide (SO2)		0.15	LB/H	0.6	LB/MMSCF		AUXILIARY BOILER USING NATURAL GAS.
OH-0307	SOUTH POINT BIOMASS GENERATION	OH	04/04/2006 ACT	AUXILIARY BOILER	FUEL OIL #2	227	MMBTU/H	Sulfur Dioxide (SO2)		2.84	LB/H	0.5	% BY WEIGHT	MAXIMUM SULFUR CONTENT OF OIL	AUXILIARY BOILER USING NUMBER 2 FUEL OIL
OR-0037	KLAMATH FALLS COGENERATION	OR	12/29/2000 ACT	AUXILIARY BOILER	NAT GAS	400	MMBTU/H	Sulfur Dioxide (SO2)	RESTRICTIONS ON S CONTENT OF FUEL	0.8	LB/MMBTU	0.8	LB/MMBTU	WHILE BURNING DISTILLATE FUEL	SEE FACILITY NOTES FOR RESTRICTIONS TO S CONTENT OF FUEL.
OR-0039	COB ENERGY FACILITY, LLC	OR	12/30/2003 ACT	DUCT BURNERS, NATURAL GAS, (4)	NATURAL GAS	654	MMBTU/H	Sulfur Dioxide (SO2)	CLEAN FUEL	0.2	LB/MMBTU	0.2	LB/MMBTU		Limit does not apply during startup, shut down, or emergency conditions
OR-0043	UMATILLA GENERATING COMPANY, L.P.	OR	05/11/2004 ACT	DUCT BURNERS	NATURAL GAS	272	MMBTU/H	Sulfur Dioxide (SO2)	CLEAN FUEL	86	NG/J	0.2	LB/MMBTU		Limit does not apply during startup, shutdown, or emergency conditions
OR-0043	UMATILLA GENERATING COMPANY, L.P.	OR	05/11/2004 ACT	TURBINE, COMBINED CYCLE & DUCT BURNER, NAT GAS (2)	NATURAL GAS	2007	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL: < 0.8% S BY WEIGHT	8000	PPMW	0			
OR-0046	TURNER ENERGY CENTER, LLC	OR	01/06/2005 ACT	ELECTRICAL POWER GENERATION	NATURAL GAS	34507448	MMBTU/YR	Sulfur Dioxide (SO2)	USE OF NATURAL GAS	0.8	% SULFUR CONTENT	0		NOT AVAILABLE	SO2 EMISSION LIMIT SET BY NSPS GG.
PA-0187	GRAYS FERRY COGEN PARTNERSHIP	PA	03/21/2001 ACT	COMBUSTION TURBINE, COMBINED CYCLE, NATURAL GAS	NATURAL GAS	1515	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE, LOW SULFUR FUEL	0.0008	LB/MMBTU	0			PERMIT LIMIT FOR TURBINE AND HRSG.
PA-0187	GRAYS FERRY COGEN PARTNERSHIP	PA	03/21/2001 ACT	COMBUSTION TURBINE, COMBINED CYCLE, FUEL OIL	#2 FUEL OIL	1515	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE, LOW SULFUR FUEL	0 203	LB/MMBTU	0			
PA-0187	GRAYS FERRY COGEN PARTNERSHIP	PA	03/21/2001 ACT	AUXILIARY BOILER, NATURAL GAS	NATURAL GAS	1119	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE, LOW SULFUR FUEL	0.0008	LB/MMBTU	0.0008	LB/MMBTU		
PA-0187	GRAYS FERRY COGEN PARTNERSHIP	PA	03/21/2001 ACT	AUXILIARY BOILER, FUEL OIL	#2 FUEL OIL	1119	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE, LOW SULFUR FUEL	0 215	LB/MMBTU	0.215	LB/MMBTU		
PA-0187	GRAYS FERRY COGEN PARTNERSHIP	PA	03/21/2001 ACT	COMBUSTION TURBINE, SIMPLE CYCLE, NATURAL GAS	NATURAL GAS	135	MW	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE, LOW SULFUR FUEL	0.0008	LB/MMBTU	0			PERMIT LIMIT FOR OPERATION OF TURBINE ONLY.
PA-0187	GRAYS FERRY COGEN PARTNERSHIP	PA	03/21/2001 ACT	COMBUSTION TURBINE, SIMPLE CYCLE, FUEL OIL	#2 FUEL OIL	135	MW	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE, LOW SULFUR FUEL	0 203	LB/MMBTU	0			PERMIT LIMIT FOR OPERATION OF TURBINE ONLY.
PA-0260	DELTA POWER PLANT	PA	01/03/2008 ACT	OIL FIRED TURBINES (6) (COMBINED CYCLE)	OIL	11 24	T/H GAL/H	Sulfur Dioxide (SO2)		0 051	LB/MMBTU	0			
PA-0260	DELTA POWER PLANT	PA	01/03/2008 ACT	OIL FIRED TURBINES (6) (SIMPLE CYCLE)	OIL	11 24	T/H GAL/H	Sulfur Dioxide (SO2)		0 051	LB/MMBTU	0			
PA-0260	DELTA POWER PLANT	PA	01/03/2008 ACT	GAS FIRED TURBINES (6) (SIMPLE CYCLE)	NG	11240	GAL/H	Sulfur Dioxide (SO2)	SCR	0 003	LB/MMBTU	0			
PA-0260	DELTA POWER PLANT	PA	01/03/2008 ACT	GAS FIRED TURBINES (60 (COMBINED CYCLE)	NG	11240	GAL/H	Sulfur Dioxide (SO2)		0 003	LB/MMBTU	0			
SC-0061	COLUMBIA ENERGY LLC	SC	04/09/2001 ACT	TURBINES, COMBINED CYCLE, NATURAL GAS (2)	NATURAL GAS	170	MW (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	4.9	LB/H	0			
SC-0061	COLUMBIA ENERGY LLC	SC	04/09/2001 ACT	BOILERS, NATURAL GAS (2)	NATURAL GAS	350	MMBTU/H (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	0.63	LB/H	0.0018	LB/MMBTU		
SC-0061	COLUMBIA ENERGY LLC	SC	04/09/2001 ACT	BOILERS, FUEL OIL (2)	NO. 2 FUEL OIL	350	MMBTU/H	Sulfur Dioxide (SO2)	COMBUSTION OF LOW SULFUR FUELS	21	LB/H	0 06	LB/MMBTU		
SC-0061	COLUMBIA ENERGY LLC	SC	04/09/2001 ACT	HOT WATER HEATERS (2)	NATURAL GAS	11	MMBTU/H	Sulfur Dioxide (SO2)	CLEAN FUEL	3.5	LB/MMBTU	3.5	LB/MMBTU		
SC-0061	COLUMBIA ENERGY LLC	SC	04/09/2001 ACT	TURBINES, COMBINED CYCLE, DISTILLATE FUEL OIL (2)	DISTILLATE FUEL OIL	170	MW (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	99	LB/H	0			
SC-0071	COLUMBIA ENERGY CENTER I-26 & US HWY 21 SOUTH	SC	04/09/2001 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS, (2)	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)	COMBUSTION OF LOW SULFUR FUELS	4.9	LB/H	0			
SC-0071	COLUMBIA ENERGY CENTER I-26 & US HWY 21 SOUTH	SC	04/09/2001 ACT	BOILERS, AUXILIARY, NATURAL GAS, (2)	NATURAL GAS	350	MMBTU/H	Sulfur Dioxide (SO2)	COMBUSTION OF LOW SULFUR FUELS	0.0018	LB/MMBTU	0.0018	LB/MMBTU		

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SC-0071	COLUMBIA ENERGY CENTER I-26 & US HWY 21 SOUTH	SC	04/09/2001 ACT	BOILER, AUXILIARY, FUEL OIL, (2)	FUEL OIL	350	MMBTU/H	Sulfur Dioxide (SO2)	COMBUSTION OF LOW SULFUR FUELS	0.0616	LB/MMBTU	0.0616	LB/MMBTU		
SC-0071	COLUMBIA ENERGY CENTER I-26 & US HWY 21 SOUTH	SC	04/09/2001 ACT	TURBINE, COMBINED CYCLE, FUEL OIL, (2)	FUEL OIL	170	MW	Sulfur Dioxide (SO2)	COMBUSTION OF LOW SULFUR FUELS	99	LB/H	0			
SC-0091	COLUMBIA ENERGY CENTER	SC	07/03/2003 ACT	BOILER, FUEL OIL	NO. 2 FUEL OIL	550	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.06	LB/MMBTU	0 06	LB/MMBTU		
SC-0091	COLUMBIA ENERGY CENTER	SC	07/03/2003 ACT	BOILER, NATURAL GAS	NATURAL GAS	550	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.0018	LB/MMBTU	0.0018	LB/MMBTU		
SC-0128	NUCOR STEEL CORPORATION (DARLINGTON PLANT)	SC	12/29/2006 ACT	REHEAT FURNACE NO.2	NATURAL GAS	180	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SPECIFICATION AND GOOD COMBUSTION PRACTICES.	0.0006	LB/MMBTU	0			THE TEST METHODS ARE METHOD 6 OR METHOD 6C.
TX-0293	GREGORY POWER FACILITY	TX	06/16/1999 ACT	FIRE WATER PUMP ENGINE, EPN106	FUEL OIL			Sulfur Dioxide (SO2)	FUEL OIL SHALL CONTAIN NO MORE THAN 0 3 WT %S	0.1	LB/H	0			
TX-0293	GREGORY POWER FACILITY	TX	06/16/1999 ACT	(2) COMBUSTION TURBINES, NO DUCT BURN, EPN 101&102	NAT GAS	185	MW, EA	Sulfur Dioxide (SO2)	PIPELINE QUALITY NAT GAS, CONTAINING NO MORE THAN 3 GR S/100 DSCF (SHORT-TERM) AND 0.25 GR S/100 DSCF 12 MO ROLLING AV	15.7	LB/H	0			
TX-0293	GREGORY POWER FACILITY	TX	06/16/1999 ACT	(2) COMBUSTION TURBINES, W/DUCT BURN, EPN101&102	NAT GAS	185	MW, EA	Sulfur Dioxide (SO2)	PIPELINE QUALITY NAT GAS, CONTAINING NO MORE THAN 3 GR S/100 DSCF (SHORT-TERM) AND 0.25 GR S/100 DSCF 12 MO ROLLING AV	19.7	LB/H	0			
TX-0293	GREGORY POWER FACILITY	TX	06/16/1999 ACT	(2) AUX PACKAGE BOILERS, EPN103 &104	NAT GAS	405	MMBTU/H	Sulfur Dioxide (SO2)	FIRED WITH PIPELINE QUALITY NAT GAS	3.4	LB/H	0.0084	LB/MMBTU	EACH UNIT	SO2 EMISSION LIMIT IN LB/MMBTU CALCULATED BY DIVIDING THE HOURLY EMISSION LIMIT BY THE THROUGHPUT.
TX-0293	GREGORY POWER FACILITY	TX	06/16/1999 ACT	DIESEL GENERATOR, EPN105	DISTILLATE FUEL			Sulfur Dioxide (SO2)	FUEL OIL SHALL CONTAIN NO MORE THAN 0 3 WT %S	2.3	LB/H	0			
TX-0297	EXXON-MOBIL BEAUMONT REFINERY	TX	03/14/2000 ACT	(3) COMBUSTION TURBINES W/DUCT BURN, 61STK001-003	NAT GAS	183	MW, EA TURBINE	Sulfur Dioxide (SO2)	FIRING NAT GAS	1.41	LB/H	0			
TX-0297	EXXON-MOBIL BEAUMONT REFINERY	TX	03/14/2000 ACT	BOILER 23, 56STK_023	NAT GAS	1121	MMBTU/H	Sulfur Dioxide (SO2)	FIRING NAT GAS AND REFINERY FUEL GAS	31.73	LB/H	0.028	LB/MMBTU	CALCULATED	SO2 STANDARD EMISSIONS CALCULATED BY DIVIDING THE HOURLY EMISSION LIMIT BY THE THROUGHPUT.
TX-0310	THE GOODYEAR TIRE & RUBBER BEAUMONT	TX	01/06/1999 ACT	BOILER, B108	NAT GAS	264	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.16	LB/H	0.0006	LB/MMBTU	SEE NOTES	STANDARD EMISSIONS CALCULATED FROM HOURLY EMISSION AND RATED HEAT INPUT.
TX-0310	THE GOODYEAR TIRE & RUBBER BEAUMONT	TX	01/06/1999 ACT	(4) GAS TURBINES, UNITS 1-4, W/OUT DUCT BURNER	NAT GAS	5	MW, EA	Sulfur Dioxide (SO2)	FIRING NAT GAS	0.04	LB/H	0			
TX-0310	THE GOODYEAR TIRE & RUBBER BEAUMONT	TX	01/06/1999 ACT	(4) GAS TURBINES, UNITS 1-4, W/DUCT BURNERS	NAT GAS	5	MW, EA	Sulfur Dioxide (SO2)	FIRING NAT GAS	0.1	LB/H	0			
TX-0369	UCC SEADRIFT OPERATIONS	TX	10/20/1999 ACT	COGEN STACK, COMBINED GT/HRSG&DB, 1180	NAT GAS	38.7	MW	Sulfur Dioxide (SO2)	FIRING PIPELINE QUALITY NAT GAS	23.43	LB/H	0			
TX-0369	UCC SEADRIFT OPERATIONS	TX	10/20/1999 ACT	COGEN STACK, TURBINE ONLY	NAT GAS	38.7	MW	Sulfur Dioxide (SO2)	FIRING PIPELINE QUALITY NAT GAS	14.88	LB/H	0			
TX-0369	UCC SEADRIFT OPERATIONS	TX	10/20/1999 ACT	COGEN STACK, PEAK LOAD - COMBINED GT/HRSG&DB, 1180	NAT GAS	44.5	MMBTU/H	Sulfur Dioxide (SO2)	FIRING PIPELINE QUALITY NAT GAS	24.62	LB/H	0			
TX-0369	UCC SEADRIFT OPERATIONS	TX	10/20/1999 ACT	COGEN STACK, HRSG&DB ONLY	NAT GAS	279.3	MMBTU/H	Sulfur Dioxide (SO2)	FUEL FOR THE HRSGU DUCT BURNERS IS LIMITED TO PIPELINE QUALITY NATURAL GAS CONTAINING NO MORE THAN 10 GR S/100 DSCF.	8.55	LB/H	0.031	LB/MMBTU	CALCULATED	
TX-0371	CORPUS CHRISTI ENERGY CENTER	TX	02/04/2000 EST	(3) TURBINE/HRSG NOS 1-3, CU1-3	NAT GAS			Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMIT	48.35	LB/H	0			
TX-0371	CORPUS CHRISTI ENERGY CENTER	TX	02/04/2000 EST	(3) AUXILIARY BOILERS 1-3, AB1-3	NAT GAS	315	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS.	9.4	LB/H	0 03	LB/MMBTU	EACH, CALCULATED	SO2 STANDARD EMISSIONS REQUIRED IN LB/MMBTU, CALCULATED FROM MAXIMUM ALLOWABLE RATES IN LB/H AND HEAT INPUT CAPACITY.
TX-0371	CORPUS CHRISTI ENERGY CENTER	TX	02/04/2000 EST	ANNUAL TOTALS FOR TURBINES & AUXILIARY BOILERS	GASEOUS FUEL			Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS.	189.3	T/YR	0			
TX-0373	ODESSA PETROCHEMICAL PLANT	TX	10/24/2002 ACT	F BOILER STACK, EYFBLRST	NAT GAS	370	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL GASES	0.22	LB/H	0.0005	LB/MMBTU	CALCULATED, SEE NOTE	STANDARDIZED EMISSION LIMIT CALCULATED FROM HEAT RATING AND HOURLY EMISSION LIMIT,
TX-0373	ODESSA PETROCHEMICAL PLANT	TX	10/24/2002 ACT	C BOILER STACK, EY003ST	NAT GAS	320	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.19	LB/H	0.0006	LB/MMBTU	CALCULATED, SEE NOTE	STANDARDIZED EMISSION LIMIT CALCULATED FROM HEAT RATING AND HOURLY EMISSION LIMIT.
TX-0383	FORNEY PLANT	TX	03/06/2000 ACT	(6) DUCT BURNERS (ALONE)	NAT GAS	550	MMBTU/H	Sulfur Dioxide (SO2)	FIRING LOW SULFUR PIPELINE NAT GAS	33.72	LB/H	0 06	LB/MMBTU	EACH, CALCULATED	HOURLY EMISSION LIMIT ONLY FOR THE DUCT BURNER ONLY.
TX-0383	FORNEY PLANT	TX	03/06/2000 ACT	(6) BLACK START GENERATORS	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.13	LB/H	0			
TX-0383	FORNEY PLANT	TX	03/06/2000 ACT	EMERGENCY DIESEL GENERATOR	DISTILLATE			Sulfur Dioxide (SO2)	NONE INDICATED	5.14	LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0383	FORNEY PLANT	TX	03/06/2000 ACT	FIREWATER PUMP ENGINE	DISTILLATE			Sulfur Dioxide (SO2)	NONE INDICATED	0.51	LB/H	0			
TX-0383	FORNEY PLANT	TX	03/06/2000 ACT	(6) TURBINES	NAT GAS	169.8	MW	Sulfur Dioxide (SO2)	FIRING LOW SULFUR PIPELINE NAT GAS	26.41	LB/H	0			HOURLY EMISSION LIMIT ONLY FOR THE SIMPLE-CYCLE TURBINE.
TX-0383	FORNEY PLANT	TX	03/06/2000 ACT	(6) COMBINED TURBINE & DUCT BURNER	NAT GAS	169.8	MW	Sulfur Dioxide (SO2)	LOW SULFUR PIPELINE NAT GAS	289.73	T/YR	0			ANNUAL LIMIT ONLY FOR COMBINED TURBINE AND DUCT BURNER. EMISSION LIMIT REQUIRED IN STANDARDIZED UNITS.
TX-0386	AMELLA ENERGY CENTER	TX	03/26/2002 ACT	TURBINES AND DUCT BURNERS (3 EACH0	NATURAL GAS	1030	MW (TOTAL)	Sulfur Dioxide (SO2)	FUEL SWEET, NATURAL GAS WITH NO MORE THAN 5.0 GRAINS (HOURLY AVERAGE) AND 0.2 GRAIN TOTAL S PER 100 DSCF (ANNUALLY)	13.6	LB/H	0			
TX-0386	AMELLA ENERGY CENTER	TX	03/26/2002 ACT	AUXILIARY BOILER	NATURAL GAS	155	MMBTU/H	Sulfur Dioxide (SO2)		0 843	LB/H	0.005	LB/MMBTU		
TX-0416	SHELL OIL DEER PARK	TX	11/24/1999 ACT	BOILER, PHENOL/ACETONE PLANT	NATURAL GAS	357	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL (5.0 GR/100 DSCF)	5.11	LB/H	0.014	LB/MMBTU	CALCULATED	
TX-0419	CHANNEL ENERGY FACILITY	TX	03/22/2000 ACT	TURBINE, COMBINED CYCLE, AND DUCT BURNER (3)	NATURAL GAS	180	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL. NATURAL GAS - 0.25 GR/100 SCF SULFUR, REFINERY GAS - 0.473 GR/100 SCF SULFUR.	31.4	LB/H	0			
TX-0419	CHANNEL ENERGY FACILITY	TX	03/22/2000 ACT	BOILER, AUXILIARY, (3)	NATURAL GAS	380	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, NATURAL GAS - 0 25 GR/100 SCF SULFUR	6.23	LB/H	0.016	LB/MMBTU		
TX-0419	CHANNEL ENERGY FACILITY	TX	03/22/2000 ACT	BOILER, AUXILIARY, (3) PROCESS GAS	NATURAL GAS	380	mmbtu/h	Sulfur Dioxide (SO2)	LOW SULFUR FUEL: NATURAL GAS/REFINERY GAS = 0.473 GR/100 SCF SULFUR	6.23	LB/H	0.016	LB/MMBTU		
TX-0469	TEXAS PETROCHEMICALS HOUSTON FACILITY	TX	10/08/2003 ACT	TURBINE AND DUCT BURNER (3)	NATURAL GAS	664	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION AND SWEET NATURAL GAS	37.06	LB/H	0			
TX-0469	TEXAS PETROCHEMICALS HOUSTON FACILITY	TX	10/08/2003 ACT	AUXILLARY STEAM BOILER (2)	NATURAL GAS	664	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION AND SWEET NATURAL GAS	4.99	LB/H	0			
TX-0479	DOW TEXAS OPERATIONS FREEPORT	TX	12/02/2004 ACT	2 WESTINGHOUSE 501F TURBINES WITH 2 735MMBTU/H DUCT BURNER (START UP)	NATURAL GAS	735	MMBTU/H	Sulfur Dioxide (SO2)	BURN CLEAN NATURAL GAS	40.14	LB/H	0			
TX-0479	DOW TEXAS OPERATIONS FREEPORT	TX	12/02/2004 ACT	2 WESTINGHOUSE 501F TURBINES WITH 2 735MMBTU/H DUCT BURNER (START-UP, SHUTDOWN, MAINTENANCE)	NATURAL GAS AND OTHER PROCESS FUELS	735	MMBTU/H	Sulfur Dioxide (SO2)		40.14	LB/H	0			
TX-0479	DOW TEXAS OPERATIONS FREEPORT	TX	12/02/2004 ACT	COMBUSTION VIA FOUR GAS-FIRED STEAM BOILERS	NATURAL GAS, OFFGAS, SYNGAS, CELL HYDROG	410	MMBTU/H	Sulfur Dioxide (SO2)	BURN CLEAN NATURAL GAS	5.41	LB/H	0			
TX-0482	COBISA GREENVILLE	TX	06/03/2005 ACT	TURBINES FIRING FUEL OIL AND DUCTS FIRING NATURAL GAS - SCENARIO 1, CASE 2	FUEL OIL/NATURAL GAS			Sulfur Dioxide (SO2)	FIRING LOW SULFUR PIPELINE-QUALITY NATURAL GAS AND FUEL OIL WILL CONTROL SO2 AND H2SO4 EMISSIONS.	683.4	LB/H	0			
TX-0482	COBISA GREENVILLE	TX	06/03/2005 ACT	TURBINES AND DUCTS FIRING NATURAL GAS - SCENARIO 1, CASE 1	NATURAL GAS	550	MMBTU/H	Sulfur Dioxide (SO2)	FIRING LOW SULFUR PIPELINE-QUALITY NATURAL GAS AND FUEL OIL WILL CONTROL SO2 AND H2SO4 EMISSIONS.	211.2	LB/H	0			
TX-0482	COBISA GREENVILLE	TX	06/03/2005 ACT	TURBINES AND DUCTS FIRING NATURAL GAS - SCENARIO 4, CASE 1	NATURAL GAS	825	mmbtu/h	Sulfur Dioxide (SO2)	FIRING LOW SULFUR PIPELINE-QUALITY NATURAL GAS AND FUEL OIL WILL CONTROL SO2 AND H2SO4 EMISSIONS.	205	LB/H	0			
TX-0482	COBISA GREENVILLE	TX	06/03/2005 ACT	TURBINES FIRING FUEL OIL AND DUCTS FIRING NATURAL GAS - SCENARIO 4, CASE 2	FUEL OIL#2/NATURAL GAS	825	MMBTU/H	Sulfur Dioxide (SO2)	FIRING LOW SULFUR PIPELINE-QUALITY NATURAL GAS AND FUEL OIL WILL CONTROL SO2 AND H2SO4 EMISSIONS.	584.1	LB/H	0			
TX-0482	COBISA GREENVILLE	TX	06/03/2005 ACT	TURBINES AND DUCTS FIRING NATURAL GAS - SCENARIO 2, CASE 1	NATURAL GAS	550	MMBTU/H	Sulfur Dioxide (SO2)	FIRING LOW SULFUR PIPELINE-QUALITY NATURAL GAS AND FUEL OIL WILL CONTROL SO2 AND H2SO4 EMISSIONS.	211.4	LB/H	0			
TX-0482	COBISA GREENVILLE	TX	06/03/2005 ACT	TURBINES FIRING FUEL OIL AND DUCTS FIRING NATURAL GAS - SCENARIO 3, CASE 2	FUEL OIL#2/NATURAL GAS	550	MMBTU/H	Sulfur Dioxide (SO2)	FIRING LOW SULFUR PIPELINE-QUALITY NATURAL GAS AND FUEL OIL WILL CONTROL SO2 AND H2SO4 EMISSIONS.	680	LB/H	0			
TX-0482	COBISA GREENVILLE	TX	06/03/2005 ACT	TURBINES FIRING FUEL OIL AND DUCTS FIRING NATURAL GAS - SCENARIO 2, CASE 2	FUEL OIL#2/NATURAL GAS	550	MMBTU/H	Sulfur Dioxide (SO2)	FIRING LOW SULFUR PIPELINE-QUALITY NATURAL GAS AND FUEL OIL WILL CONTROL SO2 AND H2SO4 EMISSIONS.	699.9	LB/H	0			
TX-0482	COBISA GREENVILLE	TX	06/03/2005 ACT	TURBINES AND DUCTS FIRING NATURAL GAS - SCENARIO 3, CASE 1	NATURAL GAS	550	MMBTU/H	Sulfur Dioxide (SO2)	FIRING LOW SULFUR PIPELINE-QUALITY NATURAL GAS AND FUEL OIL WILL CONTROL SO2 AND H2SO4 EMISSIONS.	231.5	LB/H	0			
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	TX	02/03/2006 ACT	RECYCLE ETHANE CRACKING FURNACE				Sulfur Dioxide (SO2)		1.12	LB/H	0			
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	TX	02/03/2006 ACT	FIRE WATER PUMP ENGINE (2)				Sulfur Dioxide (SO2)		1.05	LB/H	0			
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	TX	02/03/2006 ACT	BOILER (2)		425.4	MMBTU/H	Sulfur Dioxide (SO2)		12.1	LB/H	0			

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TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	TX	02/03/2006 ACT	FRESH FEED CRACKING HEATER				Sulfur Dioxide (SO2)		1.61	LB/H	0			
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	TX	02/03/2006 ACT	DP FEED HEATER				Sulfur Dioxide (SO2)		0.22	LB/H	0			
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	TX	02/03/2006 ACT	DP REACTOR REGENERATION HEATER				Sulfur Dioxide (SO2)		0.07	LB/H	0			
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	TX	02/03/2006 ACT	AUXILARY BOILER				Sulfur Dioxide (SO2)		1.24	LB/H	0			
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	TX	02/03/2006 ACT	GTG HRSG UNIT 1 GE FRAME 6B 310.4 MMBTU/H DUCT BURNER (WITH SCR)		310.4	MMBTU/H	Sulfur Dioxide (SO2)		4.46	LB/H	0			
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	TX	02/03/2006 ACT	GTG HRSG UNIT 2 GE FRAME 6B 310.4 MMBTU/HR DUCT BURNER (WITH SCR)		310.4	MMBTU/H	Sulfur Dioxide (SO2)		4.46	LB/H	0			
TX-0511	BASF ETHYLENE/PROPYLENE CRACKER	TX	02/03/2006 ACT	GROUND FLARE				Sulfur Dioxide (SO2)		165.8	LB/H	0			
TX-0526	AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	TX	08/18/2006 EST	FLARE PILOTS ONLY				Sulfur Dioxide (SO2)		0 002	LB/H	0			
TX-0526	AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	TX	08/18/2006 EST	FLARE-MSS				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0526	AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	TX	08/18/2006 EST	GAS TURBINE STACK	NATURAL GAS	700	MMBTU/H	Sulfur Dioxide (SO2)		0.92	LB/H	0			
TX-0526	AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	TX	08/18/2006 EST	REFORMER FURNACE STACK	STEAM	1373	MMBTU/H	Sulfur Dioxide (SO2)		7.3	LB/H	0			
TX-0583	MOUNTAIN CREEK STEAM ELECTRIC STATION	TX	01/12/2011 ACT	Simple Cycle Gas Turbines 1 & 2	Natural Gas	0		Sulfur Dioxide (SO2)		64	LB/H	0			Pipeline quality natural gas only
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS, DUCT BURNER	NATURAL GAS	1937	MMBTU/H	Sulfur Dioxide (SO2)		2.08	LB/H	0			
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	TURBINE, COMBINED CYCLE , FUEL OIL	DISTILLATE FUEL OIL	2080	MMBTU/H	Sulfur Dioxide (SO2)		98.9	LB/H	0			
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	BOILER, TANGENTIALLY-FIRED, UNIT 4	NATURAL GAS	2350	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS AND GOOD COMBUSTION PRACTICES.	14	T/YR	0.0014	LB/MMBTU		
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	BOILER, AUXILIARY	NATURAL GAS	99	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES.	0.1	LB/H	0.001	LB/MMBTU	EACH UNIT	
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	TURBINE, NATURAL GAS, NO DUCT BURNER FIRING	NATURAL GAS	1937	MMBTU/H	Sulfur Dioxide (SO2)		1.74	LB/H	0			
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	DUCT BURNERS	NATURAL GAS	385	MMBTU/H	Sulfur Dioxide (SO2)		0.2	LB/MMBTU	0.2	LB/MMBTU		
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	BOILER, TANGENTIALLY-FIRED, UNIT 3	NATURAL GAS	1150	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL.	14	T/YR	0.0028	LB/MMBTU		
VA-0307	HERCULES INC	VA	10/05/2007 ACT	CHEMICAL PREP	NATURAL GAS	90	MMBTU/H	Sulfur Dioxide (SO2)	CEMS AND GOOD COMBUSTION PRACTICES	0.05	LB/H	0			EMISSION LIMITS ARE FOR 1 OF 2 BOILERS
VA-0307	HERCULES INC	VA	10/05/2007 ACT	CHEMICAL PREP	DISTILLATE OIL	90	MMBTU	Sulfur Dioxide (SO2)	WET OR DRY SCRUBBER AND GOOD COMBUSTION PRACTICES	9.1	LB/H	0			
VA-0307	HERCULES INC	VA	10/05/2007 ACT	CHEMICAL PREP	RESIDUAL OIL	90	MMBTU	Sulfur Dioxide (SO2)	0 5% S AND WET OR DRY SCRUBBER. GOOD COMBUSTION PRACTICES	9.5	LB/H	0			
VA-0307	HERCULES INC	VA	10/05/2007 ACT	CHEMICAL PREP	DISTILLATE OIL	90	MMBTU	Sulfur Dioxide (SO2)	.5% S FUEL AND GOOD COMBUSTION PRACTICES	45.4	LB/H	0			
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	RECOVERY FURNACE 15		1150	TBLS/D	Sulfur Dioxide (SO2)		60	PPMDV @ 8% O2	0			
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	RECOVERY FURNACE 18		1200	TBLS/D	Sulfur Dioxide (SO2)	FACILITY WILL HAVE A FEDERAL LIMIT OF SO2 REPRESENTING A 53% REDUCTION FROM THE CURRENTLY ALLOWED EMISSION LEVELS. BACT IS NO FURTHER CONTROL APPLICATION.	60	PPMDV @ 8% O2	0			
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 15		1150	TBLS/D	Sulfur Dioxide (SO2)		12	T/YR	0			
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 18		1200	T BLS/D	Sulfur Dioxide (SO2)		4	T/YR	0			
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 19		2000	T BLS/D	Sulfur Dioxide (SO2)		16	T/YR	0			
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 22		1950	T BLS/D	Sulfur Dioxide (SO2)		31	T/YR	0			
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	LIME KILNS 1 AND 2		140	T CAO/D EACH	Sulfur Dioxide (SO2)		20	PPMDV @ 10 % O2	0			
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	LIME KILN 3		240	T CAO/D	Sulfur Dioxide (SO2)		20	PPMDV @ 10% O2	0			

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WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	POWER BOILERS 12 AND 13		444	MMBTU/H, EA	Sulfur Dioxide (SO2)		100	PPMDV @ 7% O2	0 24	LB/MMBTU		
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	POWER BOILER 20	FUEL OIL	900	MMBTU/H	Sulfur Dioxide (SO2)	LOW-SULFUR FUEL	100	PPMDV @ 7% O2	0 25	LB/MMBTU		
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	POWER BOILER 16	FUEL OIL	525	MMBTU/H	Sulfur Dioxide (SO2)		250	PPMDV @ 7% O2	0 59	LB/MMBTU		
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	POWER BOILER 17	FUEL OIL	591	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	250	PPMDV @ 7% O2	0 59	LB/MMBTU		
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	RECOVERY FURNACE 19		2000	T BLS/D	Sulfur Dioxide (SO2)	FACILITY WILL HAVE A LIMIT ON SO2 REPRESENTING A 53% REDUCTION FROM THE CURRENTLY ALLOWED EMISSION LEVELS. WITH THIS NEW BASELINE FOR POTENTIAL SO2, BACT IS NO FURTHER CONTROL.	60	PPMDV @ 8% O2	0			
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	RECOVERY FURNACE 22		1950	T BLS/D	Sulfur Dioxide (SO2)		120	PPMDV @ 8% O2	0			
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	COGEN 23	NATURAL GAS	695	MMBTU/H	Sulfur Dioxide (SO2)	ONLY PIPELINE QUALITY NATURAL GAS MAY BE USED AS FUEL	0.25	LB/MMBTU	0			EITHER POWER BOILERS 12, 13, 16, 17, OR 20 MUST BE OFF-LINE WHEN COGEN IS OPERATED.
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	LIME KILN 4		250	T CAO/D	Sulfur Dioxide (SO2)		20	PPMDV @ 10% O2	0			
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	LIME KILN 5		325	T CAO/D	Sulfur Dioxide (SO2)		20	PPMDV @ 10% O2	0			
WI-0244	APPLETON COATED COMBINED LOCKS MILL	WI	06/19/2007 ACT	BOILER B05 (#11) NATURAL GAS / DISTILLATE OIL FIRED BOILER	NATURAL GAS, DISTILLATE OIL	285	MMBTU/H	Sulfur Dioxide (SO2)	SYNTHETIC MINOR. RESTRICTION ON DISTILLATE FUEL OIL SULFUR CONTENT AND USAGE TO KEEP SO2 < 40 TPY.	0 365	LB/MMBTU	0			THE AMOUNT OF DISTILLATE FUEL OIL BURNED IN THIS BOILER MAY NOT EXCEED 215,400 GALLONS PER MONTH, AVERAGED OVER 12 CONSECUTIVE MONTHS, ONCE THE ORIGINAL CONTENTS OF THE FUEL OIL TANK HAS BEEN TOTALLY CONSUMED. MAY NOT EXCEED 127,290 GALLONS PER MONTH, AVERAGED OVER 12 CONSECUTIVE MONTHS, FOR THE ORIGINAL SUPPLY OF DISTILLATE OIL. NATURAL GAS LIMIT OF 0.001 LBS/MMBTU
MI-0357	KALKASKA GENERATING, INC	MI	02/04/2003 ACT	TURBINE, COMBINED CYCLE, (2)	NATURAL GAS	605	MW	Sulfur Oxides (SOx)	LOW SULFUR FUEL; AVERAGE SULFUR CONTENT OF FUEL IS 0.75 GR/100 SCF.	5.2	LB/H	0			Pound per hour limit is for each turbine and duct burner. Ton per year limit is for both turbines combined.
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	08/20/2009 ACT	LARGE INTERNAL COMBUSTION ENGINES (>600 HP) - UNIT HA13	DIESEL OIL	1232	HP	Sulfur Oxides (SOx)	THE UNIT SHALL COMBUST ONLY LOW-SULFUR DIESEL OIL WITH A SULFUR CONTENT LESS THAN 0 05%.	0.0004	LB/HP-H	0.0004	LB/HP-H		
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	08/20/2009 ACT	BOILER - UNIT FL01	NATURAL GAS	14 34	MMBTU/H	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	08/20/2009 ACT	SMALL INTERNAL COMBUSTION ENGINE (<600 HP) - UNIT FL12	DIESEL OIL	536	HP	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.	0.0021	LB/HP-H	0.0021	LB/HP-H		
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	08/20/2009 ACT	BOILER - UNIT BA01	NATURAL GAS	16.8	MMBTU/H	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.	0.0042	LB/MMBTU	0.0042	LB/MMBTU		
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	08/20/2009 ACT	BOILER - UNIT BA03	NATURAL GAS	31 38	MMBTU/H	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	08/20/2009 ACT	BOILER - UNIT CP01	NATURAL GAS	35.4	MMBTU/H	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	08/20/2009 ACT	BOILER - UNIT CP03	NATURAL GAS	33.48	MMBTU/H	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	08/20/2009 ACT	BOILER - UNIT CP26	NATURAL GAS	24	MMBTU/H	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
NV-0049	HARRAH'S OPERATING COMPANY, INC.	NV	08/20/2009 ACT	BOILER - UNIT IP04	NATURAL GAS	16.7	MMBTU/H	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS.	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	BOILERS - UNITS CC004, CC005, AND CC006 AT CITY CENTER	NATURAL GAS	4.2	MMBTU/H	Sulfur Oxides (SOx)	FUEL IS LIMITED TO NATURAL GAS ONLY.	0.0024	LB/MMBTU	0.0024	LB/MMBTU		EMISSION LIMIT 2 APPLIES TO EACH UNIT.
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	NATURAL GAS	4.6	MMBTU/H	Sulfur Oxides (SOx)	LIMITING THE FUEL TO NATURAL GAS ONLY.	0.0065	LB/MMBTU	0.0065	LB/MMBTU		
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	DIESEL EMERGENCY GENERATORS - UNITS CC009 THRU CC015 AT CITY CENTER	DIESEL OIL	3622	HP	Sulfur Oxides (SOx)	LIMITING SULFUR CONTENT IN THE DIESEL OIL TO 0.03% BY WEIGHT.	0.0002	LB/HP-H	0.0002	LB/HP-H		EMISSION LIMIT 2 APPLIES TO EACH UNIT.
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	WATER HEATERS - UNITS NY037 AND NY038 AT NEW YORK - NEW YORK	NATURAL GAS	2	MMBTU/H	Sulfur Oxides (SOx)	LIMITING FUEL TO NATURAL GAS ONLY.	0.0006	LB/MMBTU	0.0006	LB/MMBTU		EMISSION LIMIT 2 APPLIES TO EACH UNIT.
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	EMERGENCY GENERATORS - UNITS LX024 AND LX025 AT LUXOR	DIESEL OIL	2206	HP	Sulfur Oxides (SOx)	LIMITING SULFUR CONTENT IN THE DIESEL OIL TO 0.03%	0.0002	LB/HP-H	0.0002	LB/HP-H		EMISSION LIMIT 2 APPLIES TO EACH UNIT.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas > 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	BOILER - UNIT MB090 AT MANDALAY BAY	NATURAL GAS	4.3	MMBTU/H	Sulfur Oxides (SOx)	LIMITING THE FUEL TO NATURAL GAS ONLY	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	BOILERS - UNITS BE102 THRU BE105 AT BELLAGIO	NATURAL GAS	2	MMBTU/H	Sulfur Oxides (SOx)	LIMITING THE FUEL TO NATURAL GAS ONLY	0.0006	LB/MMBTU	0.0006	LB/MMBTU		EMISSION LIMIT 2 APPLIES TO EACH UNIT.
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	BOILER - UNIT BE111 AT BELLAGIO	NATURAL GAS	2.1	MMBTU/H	Sulfur Oxides (SOx)	LIMITING THE FUEL TO NATURAL GAS ONLY AND GOOD COMBUSTION PRACTICES	0.0048	LB/MMBTU	0.0048	LB/MMBTU		
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	SMALL INTERNAL COMBUSTION ENGINE - UNIT EX012 AT EXCALIBUR	DIESEL OIL	350	HP	Sulfur Oxides (SOx)	SULFUR CONTENT IN THE FUEL IS LIMITED TO 500 PPM.	0.0004	LB/HP-H	0.0004	LB/HP-H		
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	BOILERS - UNITS CC026, CC027 AND CC028 AT CITY CENTER	NATURAL GAS	44	MMBTU/H	Sulfur Oxides (SOx)	LIMITING THE FUEL TO NATURAL GAS ONLY	0.0007	LB/MMBTU	0.0007	LB/MMBTU		EMISSION LIMIT 2 APPLIES TO EACH UNIT.
NV-0050	MGM MIRAGE	NV	11/30/2009 ACT	BOILERS - UNITS NY42, NY43, AND NY44 AT NEW YORK - NEW YORK	NATURAL GAS	2	MMBTU/H	Sulfur Oxides (SOx)	LIMITING THE FUEL TO NATURAL GAS ONLY	0 005	LB/MMBTU	0.005	LB/MMBTU		EMISSION LIMIT 2 APPLIES TO EACH UNIT.
OR-0039	COB ENERGY FACILITY, LLC	OR	12/30/2003 ACT	TURBINE, COMBINED CYCLE, DUCT BURNER, NAT GAS, (4)	NATURAL GAS	1150	MW	Sulfur Oxides (SOx)	LOW SULFUR FUEL: < 0.8 % S BY WT.	0		0			Limit is low sulfur fuel. No emission rate limit.
IA-0067	WALTER SCOTT JR. ENERGY CENTER	IA	06/17/2003 ACT	CBEC 4 BOILER	PRB COAL	7675	MMBTU/H	Sulfur, Total Reduced (TRS)	LIME SPRAY DRYER FLUE GAS DESULFURIZATION	0 001	LB/MMBTU	0			Costs are the same as those for SO2. Cost effectiveness was not calculated.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	BLEACH PLANT NO. 2		668	T/D	Sulfur, Total Reduced (TRS)		0.12	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 1		2 81	MM LB/D	Sulfur, Total Reduced (TRS)	UPGRADE BLOX SYSTEM	4.53	LB/H	0			ADDITIONAL EMISSION LIMIT: 5 PPMV AT 8% O2
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 2		3 96	MM LB/D	Sulfur, Total Reduced (TRS)	UPGRADE BLOX SYSTEM	6.13	LB/H	0			ADDITIONAL EMISSION LIMIT: 5 PPMV AT 8% O2
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	BLEACH PLANT NO. 1		1024	T/D	Sulfur, Total Reduced (TRS)		0.19	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	SMELT TANK NO. 1		3 32	MM LB BLS/D	Sulfur, Total Reduced (TRS)		0.84	LB/H	0.032	LB/T BLS	CALCULATED	ADDITIONAL EMISSION LIMIT USED TO CALCULATE STANDARDIZED EMISSIONS: 0.016 G/KG BLS FIRED.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	SMELT TANK NO. 2		2 25	MM LB BLS/D	Sulfur, Total Reduced (TRS)	WET SCRUBBER	0.63	LB/H	0.032	LB/T BLS	CALCULATED	ADDITIONAL EMISSION LIMIT USED TO CALCULATE STANDARDIZED EMISSIONS: 0.016 G/KG BLS FIRED.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	LIME KILN NO. 1		340	T/D	Sulfur, Total Reduced (TRS)		3.5	LB/H	8	PPMV @ 10% O2		
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	LIME KILN NO. 2		270	T/D	Sulfur, Total Reduced (TRS)		2.81	LB/H	8	PPMV @ 10% O2		
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	POWER BOILER NO. 5	NATURAL GAS	987	MMBTU/H	Sulfur, Total Reduced (TRS)		0.48	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	BLEACH PLANT NO. 3		623	T/D	Sulfur, Total Reduced (TRS)		0.11	LB/H	0			.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	COMBINATION BOILER NO. 1	WOOD WASTE / NAT GAS	459.5	MMBTU/H	Sulfur, Total Reduced (TRS)		0.46	LB/H	0			
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	RECOVERY FURNACE 15		1150	TBLS/D	Sulfur, Total Reduced (TRS)		17.5	PPMDV @ 8% O2	0			ASSUME ALL TRS IS H2S
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	RECOVERY FURNACE 18		1200	TBLS/D	Sulfur, Total Reduced (TRS)	NO FURTHER CONTROL APPLICATION IS EITHER FEASIBLE OR ECONOMICALLY JUSTIFIABLE.	17.5	PPMDV @ 8% O2	0			ASSUME ALL TRS IS H2S
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 15		1150	TBLS/D	Sulfur, Total Reduced (TRS)		67	T/YR	0			ASSUME ALL TRS IS H2S.
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 18		1200	T BLS/D	Sulfur, Total Reduced (TRS)		67	T/YR	0			ASSUME ALL TRS IS H2S.
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 19		2000	T BLS/D	Sulfur, Total Reduced (TRS)		114	T/YR	0			ASSUME ALL TRS IS H2S.
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	SMELT DISSOLVING TANK 22		1950	T BLS/D	Sulfur, Total Reduced (TRS)		0.0168	LB/T BLS	0			ASSUME THAT ALL TRS IS H2S.
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	LIME KILNS 1 AND 2		140	T CAO/D EACH	Sulfur, Total Reduced (TRS)		20	PPMDV @ 10% O2	0			ASSUME ALL TRS IS H2S.
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	LIME KILN 3		240	T CAO/D	Sulfur, Total Reduced (TRS)		20	PPMDV @ 10% O2	0			ASSUME THAT ALL TRS IS H2S.
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	RECOVERY FURNACE 19		2000	T BLS/D	Sulfur, Total Reduced (TRS)	FURTHER CONTROL IS EITHER INFEASIBLE OR NOT ECONOMICALLY JUSTIFIABLE.	10	PPMDV @ 8% O2	0			ASSUME ALL TRS IS H2S
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	RECOVERY FURNACE 22		1950	T BLS/D	Sulfur, Total Reduced (TRS)		3	PPMDV @ 8% O2	0			ASSUME THAT ALL TRS IS H2S.
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	LIME KILN 4		250	T CAO/D	Sulfur, Total Reduced (TRS)		20	PPMDV @ 10% O2	0			ASSUME ALL TRS IS H2S
WA-0303	LONGVIEW FIBRE PAPER AND PACKAGING, INC	WA	11/01/2006 ACT	LIME KILN 5		325	T CAO/D	Sulfur, Total Reduced (TRS)		20	PPMDV @ 10% O2	0			ASSUME ALL TRS IS H2S

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas > 100 million BTU/hr & < 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	Z-HIGH MILL WITH MIST ELIMINATOR (LO42) (MULTIPLE EMISSION POINTS)				Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LO43).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS -FIRED ANNEALING FURNACE (LA43) (MULTIPLE EMISSION POINTS)	NATURAL GAS	196.4	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LA43).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	2 ACID REGENERATION LINES EACH WITH CAUSTIC SCRUBBERS & COMMON SCR (LO72) (MULTIPLE EMISSION POINTS)	NATURAL GAS	20600	T/YR	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE 2 ACID REGENERATION LINES EACH WITH CAUSTIC SCRUBBER & COMMON SCR (LO72).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	DEGREASING WITH WET SCRUBBER (LO52) (MULTIPLE EMISSION POINTS)		60	T/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LO53).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	DEGREASING WITH WET SCRUBBER (MULTIPLE EMISSION POINTS)		60	T/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE.
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED BATCH ANNEALING FURNACES (LA63, LA64)	NATURAL GAS	33.4	MMBTU each	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED PASSIVE ANNEALING FURNACE (LO41)	NATURAL GAS	27.2	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	4 CONTINUOUS HOT DIP GALVANIZING LINE (EACH LINE WITH SAME MULTIPLE EMISSION POINTS)				Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 EMISSIONS FOR THE ANTI-CORROSIVE COATING WITH PRE & POST DRYERS.
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	4 CONTINUOUS HOT DIP GALVANIZING LINE (EACH LINE WITH SAME MULTIPLE EMISSION POINTS)				Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 EMISSIONS FOR THE ANNEALING FURNACES.
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	MELTSHOP - LO (MULTIPLE EMISSION POINTS)		126	T/H	Sulfur Dioxide (SO2)		0.15	LB/T	0			THIS COVERS SO2 EMISSIONS FOR THE AOD CONVERTER WITH ELEPHANT HOUSE & 2 LMFS VENTED TO COMMON BAGHOUSE (LO2).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	MELTSHOP - LO (MULTIPLE EMISSION POINTS)		126	T/H	Sulfur Dioxide (SO2)		0.15	LB/T	0			THIS COVERS SO2 FOR THE TPH EAF WITH DEC & ELEPHANT HOUSE VENTED TO BAGHOUSE (LO1).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	TPH ELECTRIC ARC FURNACE WITH DEC & ELEPHANT HOUSE VENTED TO BAGHOUSE 3 (LA1) (MULTIPLE EMISSION POINTS)	NATURAL GAS	126	T/H	Sulfur Dioxide (SO2)		0.15	LB/T	0			THIS COVERS SO2 FOR THE TPH ELECTRIC ARC FURNACE WITH DEC & ELEPHANT HOUSE VENTED TO BAGHOUSE 3 (LA1).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	TPH ELECTRIC ARC FURNACE WITH DEC & ELEPHANT HOUSE VENTED TO BAGHOUSE 3 (LA1) (MULTIPLE EMISSION POINTS)	NATURAL GAS	126	T/H	Sulfur Dioxide (SO2)		0.15	LB/T	0			THIS COVERS SO2 FOR THE ARGON-OXYGEN DECARBURIZATION FURNACE WITH ELEPHANT HOUSE & 2 LADLE METALLURGY STATIONS VENTED TO COMMON BAGHOUSE.
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	169	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED REHEAT FURNACE (LA 21).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	169	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE 3 COIL DRUM FURNACES (LA24-LA26).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	169	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE PLATE ANNEALING FURNACE (LA27).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	BAL STEAM SWEEP WITH MIST ELIMINATOR (LA66) (MULTIPLE EMISSION POINTS)		12.6	T/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LA70).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	3 NATURAL GAS-FIRED BOILERS WITH ULNB & EGR (537-539)	NATURAL GAS	64.9	MMBTU each	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	HOT STRIP MILL (MULTIPLE EMISSION POINTS)	NATURAL GAS	690	T/H	Sulfur Dioxide (SO2)		0 006	LB/MMBTU	0			THIS COVERS SO2 EMISSIONS FROM THE 4 NATURAL GAS-FIRED WALKING BEAM REHEAT FURNACES.
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	HCL ACID REGENERATION (MULTIPLE EMISSION POINTS)	NATURAL GAS	3.77	T/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 EMISSIONS FOR THE 2 REGENERATION TRAINS WITH CAUSTIC SCRUBBER (5-10).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED BATCH ANNEALING FURNACE (535)	NATURAL GAS	99	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AR-0026	PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	05/05/1999 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)	COMBUSTION OF LOW SULFUR FUELS NO FUEL > 0.5% BY WEIGHT SULFUR.	0.0006	LB/MMBTU	0			
AR-0026	PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	05/05/1999 ACT	BOILER, NATURAL GAS	NATURAL GAS	362	MMBTU/H	Sulfur Dioxide (SO2)	COMBUSTION OF LOW SULFUR FUELS (< 0 05% BY WT S)	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
AR-0026	PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	05/05/1999 ACT	BOILER, FUEL OIL	DISTILLATE FUEL OIL	346	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUELS: < .05% BY WT S	0 052	LB/MMBTU	0.052	LB/MMBTU		
AR-0026	PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	05/05/1999 ACT	TURBINE, COMBINED CYCLE, FUEL OIL	DISTILLATE OIL	170	MW	Sulfur Dioxide (SO2)	COMBUSTION OF LOW S FUELS: 0.5% BY WT S	0.0487	LB/MMBTU	0			
AR-0026	PINE BLUFF ENERGY LLC - PINE BLUFF ENERGY CENTER	AR	05/05/1999 ACT	DUCT BURNER	NATURAL GAS	315	MMBTU/H	Sulfur Dioxide (SO2)	CLEAN FUEL	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	FURNACE, LADLE METALLURGY		225	T/H	Sulfur Dioxide (SO2)	LOW SULFUR COKE USE.	0 076	LB/T	0			
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	PROCESS HEATERS	NATURAL GAS			Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	FURNACE, ELECTRIC ARC		225	T/H	Sulfur Dioxide (SO2)	LOW SULFUR COKE/SCRAP MANAGEMENT.	1.5	LB/T	0			
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	REHEAT FURNACE	NATURAL GAS	225	MMBTU/H	Sulfur Dioxide (SO2)	CLEAN FUELS	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	LADLE PREHEAT & DRYOUT STATIONS	NATURAL GAS	225	T/H	Sulfur Dioxide (SO2)	CLEAN FUEL	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
AR-0057	TENASKA ARKANSAS PARTNERS, LP	AR	10/09/2001 ACT	BOILER, NATURAL GAS, (2)	NATURAL GAS	122	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SPECIFICATION: NATURAL GAS.	0 006	LB/MMBTU	0.006	LB/MMBTU		
AR-0057	TENASKA ARKANSAS PARTNERS, LP	AR	10/09/2001 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS	NATURAL GAS	185	MW	Sulfur Dioxide (SO2)	FUEL SPECIFICATION: LOW SULFUR FUELS.	0 006	LB/MMBTU	0			
AR-0057	TENASKA ARKANSAS PARTNERS, LP	AR	10/09/2001 ACT	TURBINE, COMBINED CYCLE, FUEL OIL	FUEL OIL	185	MW	Sulfur Dioxide (SO2)	FUEL SPECIFICATION: LOW SULFUR FUELS.	0.05	LB/MMBTU	0			
FL-0251	OKEELANTA CORPORATION SUGAR MILL	FL	10/29/2001 ACT	BOILER, NATURAL GAS	NATURAL GAS	211	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SPECIFICATIONS	0		0		see notes	BACT is pipeline natural gas. State BACT, Rule 62-296.406 FAC
FL-0251	OKEELANTA CORPORATION SUGAR MILL	FL	10/29/2001 ACT	BOILER, FUEL OIL	FUEL OIL	211	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SPECIFICATIONS: LOW SULFUR (0 05% S BY WT)	0		0		see notes	BACT is low sulfur fuel. State BACT, rule 62-296.406 FAC
IN-0085	PSEG LAWRENCEBURG ENERGY FACILITY	IN	06/07/2001 ACT	TURBINE, NATURAL GAS, COMBINED CYCLE FOUR	NATURAL GAS	476.6	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR NATURAL GAS (LESS THAN 2 G/DSCF). EMISSION LIMIT IS FOR EACH CT	11	LB/H	0			
IN-0085	PSEG LAWRENCEBURG ENERGY FACILITY	IN	06/07/2001 ACT	AUXILIARY BOILER, NATURAL GAS	NATURAL GAS	124.6	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR NATURAL GAS (LESS THAN %0.8 BY WEIGHT)	0 006	LB/MMBTU	0.006	LB/MMBTU		
LA-0131	CLECO EVANGELINE LLC	LA	12/21/1999 ACT	GAS TURBINES, 3	NATURAL GAS	1799	MMBTU/H EACH	Sulfur Dioxide (SO2)		2	LB/H	0			
LA-0131	CLECO EVANGELINE LLC	LA	12/21/1999 ACT	HRSG, UNIT 6	NATURAL GAS	300	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES	0.2	LB/H	0.0007	LB/MMBTU		THE EMISSION LIMIT IN STANDARD UNITS WAS CALCULATED FROM THE HOURLY EMISSION LIMIT IN THE PERMIT AND THE HRSG'S THROUGHPUT; 0.2 LB/H / 300 MMBTU/HR
LA-0131	CLECO EVANGELINE LLC	LA	12/21/1999 ACT	HRSGS, UNITS 7-1, 7-2	NATURAL GAS	166	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES	0.1	LB/H	0.0006	LB/MMBTU		THE EMISSION LIMIT IN STANDARD UNITS WAS CALCULATED FROM THE HOURLY EMISSION LIMIT IN THE PERMIT AND THE SOURCE'S THROUGHPUT; 0.1 LB/H / 166 MMBTU/HR
LA-0238	ALLIANCE REFINERY	LA	07/10/2009 ACT	FCCU FEED HEATER	REFINERY GAS	181.7	MMBTU/H	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART J	4.79	LB/H	0			
LA-0238	ALLIANCE REFINERY	LA	07/10/2009 ACT	CO BOILERS (2)	REFINERY GAS	831.3	MMBTU/H EACH	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART J	1286	LB/H	0			
LA-0238	ALLIANCE REFINERY	LA	07/10/2009 ACT	FCCU REGEN VENT - SU/SD OPERATIONS		89000	BBL/D	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART J	1286	LB/H	0			
MI-0368	MICHIGAN PAPERBOARD COMPANY	MI	09/08/2004 ACT	BOILER	FUEL OIL	185	MMBTU/H	Sulfur Dioxide (SO2)		280	LB/H	1 51	LB/MMBTU	CALCULATED	NO SIMILAR SIZED UNITS IDENTIFIED IN RBLC WITH CONTROL REQUIREMENTS FOR SO2.
MN-0039	MINNESOTA CORN PROCESSORS	MN	08/08/2000 ACT	BOILER, NATURAL GAS	NATURAL GAS	237.4	MMBTU/H	Sulfur Dioxide (SO2)	FUEL LIMITED TO NATURAL GAS ONLY	0.4	LB/H	0.0017	LB/MMBTU		
MN-0039	MINNESOTA CORN PROCESSORS	MN	08/08/2000 ACT	CORN GLUTEN DRYER	NATURAL GAS	39	MMBTU/H	Sulfur Dioxide (SO2)	FUEL LIMITED TO NATURAL GAS OR PROCESS GAS	15	LB/H	0			
MN-0076	BLANDIN PAPER/RAPIDS ENERGY CENTER	MN	09/18/2008 ACT	BOILER	NATURAL GAS	280	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS ONLY	0		0			NO EMISSION LIMITS AVAILABLE
NC-0073	BRIDGESTONE FIRESTONE	NC	06/28/2001 ACT	BOILERS, (2)	NATURAL GAS	121	MMBTU/H	Sulfur Dioxide (SO2)	FUEL OIL < 0.5 % S BY WT	2.3	LB/MMBTU	2.3	LB/MMBTU		
NJ-0036	AES RED OAK LLC	NJ	10/24/2001 ACT	AUXILIARY BOILER- DISTILLATE OIL	DISTILLATE FUEL OIL	99	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR OIL (NO PERCENTAGES GIVEN)	5 021	LB/H	0.0507	LB/MMBTU		
NJ-0036	AES RED OAK LLC	NJ	10/24/2001 ACT	FUEL GAS HEATER	NATURAL GAS	16	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL	0 069	LB/H	0.0043	LB/MMBTU		
NJ-0036	AES RED OAK LLC	NJ	10/24/2001 ACT	AUXILIARY BOILER	NATURAL GAS	120	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL	0 514	LB/H	0.0043	LB/MMBTU		

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas > 100 million BTU/hr & < 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
NJ-0036	AES RED OAK LLC	NJ	10/24/2001 ACT	EMERGENCY GENERATOR	DIESEL FUEL	49	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	2.45	LB/H	0			
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 4 (NAT GAS)	NATURAL GAS	118	MMBTU/H	Sulfur Dioxide (SO2)	NONE LISTED	0.1	LB/H	0.0008	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 1 (NO. 2 OIL)	NATURAL GAS	84.4	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL- 0.05% BY WEIGHT	4.3	LB/H	0.051	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 2 (NAT GAS)	NATURAL GAS	134	MMBTU/H	Sulfur Dioxide (SO2)	NONE LISTED	0.1	LB/H	0.0007	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 3 (NAT GAS)	NATURAL GAS	152	MMBTU/H	Sulfur Dioxide (SO2)	NONE LISTED	0.1	LB/H	0.0007	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 3 (NO. 2 OIL)	NAT GAS	241.6	MMBTU/H	Sulfur Dioxide (SO2)	LIMITED OPERATING HOURS FOR NO. 2 OIL; FUEL SULFUR LIMIT OF 0 05% BY WEIGHT.	12.4	LB/H	0.0513	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 2 (NO. 2 OIL)	NAT GAS	230.8	MMBTU/H	Sulfur Dioxide (SO2)	LIMITED OPERATING HOURS FOR NO. 2 OIL, FUEL SULFUR LIMIT OF 0 05% BY WEIGHT.	11.9	LB/H	0.0516	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 4 (NO. 2 OIL)	NAT GAS	204.2	MMBTU/H	Sulfur Dioxide (SO2)	LIMITED OPERATING HOURS FOR NO. 2 OIL; FUEL SULFUR LIMIT OF 0 05% BY WEIGHT.	10.5	LB/H	0.0514	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 1 (NATURAL GAS)	NATURAL GAS	84.4	MMBTU/H	Sulfur Dioxide (SO2)	NONE LISTED	0.1	LB/H	0.001	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 1 (LASALOCID OIL & NO. 2 OIL COMBINED)	NATURAL GAS	35.5	MMBTU/H	Sulfur Dioxide (SO2)	LIMITED OPERATING HOURS FOR NO. 2 OIL; NO. 2 OIL LIMITED TO 0.05% SULFUR BY WEIGHT.	2.8	LB/H	0.079	LB/MMBTU		
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	AUXILIARY BOILER	NATURAL GAS	200	MMBTU/H	Sulfur Dioxide (SO2)	NONE	0.8	LB/H	0.004	LB/MMBTU		BASIS OF LIMIT IS STATE.
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	DUCT BURNER (3)	NATURAL GAS	256	MMBTU/H	Sulfur Dioxide (SO2)	NONE LISTED	0.2	LB/MMBTU	0.2	LB/MMBTU		
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	COMBINED CYCLE TURBINE WITH DUCT BURNER	NATURAL GAS	3202	MMBTU/H	Sulfur Dioxide (SO2)	NONE LISTED	0 004	LB/MMBTU	0.8	PPM @ 15% O2		
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	EMERGENCY GENERATOR	DISTILLATE OIL	14.1	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR IN OIL LIMITED TO 0.05% BY WEIGHT.	0.8	LB/H	0			
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	COMBINED CYCLE TURBINE (3)	NATURAL GAS	2964	MMBTU/H	Sulfur Dioxide (SO2)	ONLY USE NATURAL GAS WITH SULFUR CONTENT 0.8%	0 004	LB/MMBTU	0.8	PPM @ 15% O2		BASIS OF LIMIT IS STATE
NJ-0043	LIBERTY GENERATING STATION	NJ	03/28/2002 ACT	DIESEL FIRE PUMP	DISTILLATE OIL	3.5	MMBTU/H	Sulfur Dioxide (SO2)	NONE	1	LB/H	0			
OH-0241	MILLER BREWING COMPANY - TRENTON	OH	05/27/2004 ACT	BOILER (2), NO. 6 FUEL OIL	NO. 6 FUEL OIL	238	MMBTU/H	Sulfur Dioxide (SO2)		1.6	LB/MMBTU	1.6	LB/MMBTU		PERMIT MODIFIED FROM 1.4 LB SO2/MMBTU WHICH COULD NOT BE MET.
OH-0241	MILLER BREWING COMPANY - TRENTON	OH	05/27/2004 ACT	BOILER (2), NATURAL GAS	NATURAL GAS	238	MMBTU/H	Sulfur Dioxide (SO2)		1.6	LB/MMBTU	1.6	LB/MMBTU		
OH-0241	MILLER BREWING COMPANY - TRENTON	OH	05/27/2004 ACT	BOILER (2), COAL FIRED	COAL	238	MMBTU/H	Sulfur Dioxide (SO2)		1.6	LB/MMBTU	1.6	LB/MMBTU		PERMIT MODIFIED FROM 1.4 LB SO2/MMBTU WHICH COULD NOT BE MET.
OH-0241	MILLER BREWING COMPANY - TRENTON	OH	05/27/2004 ACT	BOILER (2), NO. 2 FUEL OIL	NO. 2 FUEL OIL	238	MMBTU/H	Sulfur Dioxide (SO2)		1.6	LB/MMBTU	1.6	LB/MMBTU		PERMIT MODIFIED FROM 1.4 LB SO2/MMBTU WHICH COULD NOT BE MET.
OH-0245	REPUBLIC TECHNOLOGIES INTERNATIONAL	OH	01/27/1999 ACT	ELECTRIC ARC FURNACE (EAF) NO. 7, P905		85	T/H	Sulfur Dioxide (SO2)	LOOKED AT CHARGE SUBSTITUTION (NOT FEASIBLE) AND SO2 CONTROLS (NOT FEASIBLE)	5.95	LB/H	0			
OH-0245	REPUBLIC TECHNOLOGIES INTERNATIONAL	OH	01/27/1999 ACT	ELECTRIC ARC FURNACE (EAF) NO. 9, P907		165	T/H	Sulfur Dioxide (SO2)	LOOKED AT CHARGE SUBSTITUTION (NOT FEASIBLE) AND SO2 CONTROLS (NOT FEASIBLE)	11.55	LB/H	0			
OH-0245	REPUBLIC TECHNOLOGIES INTERNATIONAL	OH	01/27/1999 ACT	BLOOM REHEAT FURNACE	NATURAL GAS	196.2	MMBTU/H	Sulfur Dioxide (SO2)		0.12	LB/H	0.0006	LB/MMBTU		
OH-0245	REPUBLIC TECHNOLOGIES INTERNATIONAL	OH	01/27/1999 ACT	LADLE METALLURGY FACILITY (LMF), P123				Sulfur Dioxide (SO2)	LOOKED AT CHARGE SUBSTITUTION (NOT FEASIBLE) & FLUE GAS DESULFURIZATION. LOOKED AT ADD-ON CONTROLS (WET SCRUBBER, SPRAY DRYER ABORPTION AND DRY SORBENT INJECTION)	525	LB/3 H PERIOD	0			Additional limit: 318.84 T/YR
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	OH	10/08/2009 ACT	AUXILIARY BOILER	NATURAL GAS	150	MMBTU/H	Sulfur Dioxide (SO2)		0.09	LB/H	0.6	LB/MMCF		

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas > 100 million BTU/hr & < 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
OH-0310	AMERICAN MUNICIPAL POWER GENERATING STATION	OH	10/08/2009 ACT	BOILER (2), PULVERIZED COAL FIRED	PULVERIZED COAL	5191	MMBTU/H	Sulfur Dioxide (SO2)	WET FLUE GAS DESULFURIZATION (FGS) EITHER LIME OR AMMONIA-BASED	1246	LB/H	0.15	LB/MMBTU	HEAT INPUT AS A 30-DAY ROLLING AVERAGE	ADDITIONAL LIMITS: 0.184 LB/MMBTU HEAT INPUT AS A 24-HOUR ROLLING AVERAGE; 0.2400 LB/MMBTU HEAT INPUT, AS 3-HR AVERAGE CEM FOR SO2. THESE LIMITS ARE FOR EACH OF 2 BOILERS; TOTAL EMISSIONS ARE TIMES 2.
OH-0336	CAMPBELL SOUP COMPANY	OH	12/14/2010 ACT	Boilers (3)	Natural Gas	0		Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
OH-0336	CAMPBELL SOUP COMPANY	OH	12/14/2010 ACT	Bolier (3)	Number 2 fuel oil	3246593	GAL/YR	Sulfur Dioxide (SO2)		0.35	T/YR	0.0015	LB/MMBTU	NUMBER 2 OIL STANDARD	
*OH-0354	KRATON POLYMERS U.S. LLC	OH	01/15/2013 ACT	Two 249 MMBtu/H boilers	Natural Gas	249	MMBtu/H	Sulfur Dioxide (SO2)	Burning low sulfur fuels with less than 0 05 % sulfur.	11.24	T/YR	1.6	LB/MMBTU	BURNING DISTILLATE OIL	Netted out for SO2 by replacing old coal/oil-fired boilers.
OK-0045	REDBUD POWER PLT	OK	08/15/2001 ACT	BOILER, AUXILIARY	NATURAL GAS	20	MMBTU/H	Sulfur Dioxide (SO2)	PIPELINE QUALITY NATURAL GAS FUEL	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
OK-0045	REDBUD POWER PLT	OK	08/15/2001 ACT	TURBINE, COMBINED CYCLE, (4)	NATURAL GAS	1698	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL - PIPELINE QUALITY NATURAL GAS	0 005	LB/MMBTU	0		Not Available	
SC-0049	SKYGEN	SC	12/02/1999 ACT	SIMPLE COMBUSTION TURBINES, 3, NG/NO. 2 FUEL FIRED	NATURAL GAS	171	MW	Sulfur Dioxide (SO2)	SULFURIC ACID MIST, USE LOW SULFUR FUELS (<0 05 %S) EMISSION LIMITTION FOR NO. 2 FUELS	11	LB/H	0			
SC-0049	SKYGEN	SC	12/02/1999 ACT	SIMPLE COMBUSTION TURBINES, 3, NG/NO. 2 FUEL FIRED	NATURAL GAS	171	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUELS (<0.05 %SO2) EMISSION LIMITS - 1.1 LB/H NG, 99 LB/H NO. 2 ALTERNATE LIMITS - 1.65 T/YR - NG, 24.75 T/YR NO. 2	1.1	LB/H NG	0			
SC-0049	SKYGEN	SC	12/02/1999 ACT	THREE NATURAL GAS FIRED BOILERS (UTILITY)	NATURAL GAS	230	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
SC-0049	SKYGEN	SC	12/02/1999 ACT	SIMPLE COMBUSTION TURBINES, 3, NO. 2 FUEL OIL	NATURAL GAS	171	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUELS (<0.05 %SO2) EMISSION LIMITS - 1.1 LB/H NG, 99 LB/H NO. 2 ALTERNATE LIMITS - 1.65 T/Y - NG 24.75 T/Y NO. 2	99	LB/H	0			
TN-0089	PROCTOR & GAMBLE MANUFACTURING COMPANY	TN	03/05/2001 ACT	UTILITY BOILER #2 (NAT GAS)	NATURAL GAS	183	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SPEC: SULFUR CONTENT OF FUEL SHALL NOT EXCEED 0.2% BY WEIGHT.	0		0		NOT AVAILABLE	SO2 (LB/H)=(MAX OIL USAGE)(EFSO2), WHEN USING NO.2 FUEL OIL. TONSO2=(EFSO2)(ANNUAL OIL USAGE)/2000+(0.6)(ANNUAL GAS USAGE)/2000. WHERE: EFSO2=(142)(SULFUR PERCENT IN #2 FUEL OIL).
TN-0089	PROCTOR & GAMBLE MANUFACTURING COMPANY	TN	03/05/2001 ACT	UTILITY BOILER #2 (FUEL OIL)	NO.2 FUEL OIL	183	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SPEC: SULFUR CONTENT OF FUEL SHALL NOT EXCEED 0.2% BY WEIGHT.	0		0		NOT AVAILABLE	SO2 (LB/H)=(MAX OIL USAGE)(EFSO2), WHEN USING NO.2 FUEL OIL. TONSO2=(EFSO2)(ANNUAL OIL USAGE)/2000+(0.6)(ANNUAL GAS USAGE)/2000. WHERE: EFSO2=(142)(SULFUR PERCENT IN #2 FUEL OIL).
TN-0089	PROCTOR & GAMBLE MANUFACTURING COMPANY	TN	03/05/2001 ACT	UTILITY BOILER #50-1 (NAT GAS)	NATURAL GAS	225	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SPEC: SULFUR CONTENT OF FUEL SHALL NOT EXCEED 0.2% BY WEIGHT.	0		0			SO2 (LB/H)=(MAX OIL USAGE)(EFSO2), WHEN USING NO.2 FUEL OIL. TONSO2=(EFSO2)(ANNUAL OIL USAGE)/2000+(0.6)(ANNUAL GAS USAGE)/2000. WHERE: EFSO2=(142)(SULFUR PERCENT IN #2 FUEL OIL).
TN-0089	PROCTOR & GAMBLE MANUFACTURING COMPANY	TN	03/05/2001 ACT	UTILITY BOILER #50-1 (FUEL OIL)	NO.2 FUEL OIL	225	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SPEC: SULFUR CONTENT OF FUEL SHALL NOT EXCEED 0.2% BY WEIGHT.	0		0			SO2 (LB/H)=(MAX OIL USAGE)(EFSO2), WHEN USING NO.2 FUEL OIL. TONSO2=(EFSO2)(ANNUAL OIL USAGE)/2000+(0.6)(ANNUAL GAS USAGE)/2000. WHERE: EFSO2=(142)(SULFUR PERCENT IN #2 FUEL OIL).
TN-0146	FLORIM, USA, INC.	TN	12/20/2000 ACT	GAS-FIRED KILNS	NATURAL GAS	125	MMBTU/H	Sulfur Dioxide (SO2)	COATED BAGHOUSE, HYDRATED CALCIUM MEDIUM.	0 266	LB/MMBTU	0.266	LB/MMBTU		The facility must meet compliance with production limits and recordkeeeping requirements to demonstrate compliance with emission limits.
TX-0386	AMELLA ENERGY CENTER	TX	03/26/2002 ACT	TURBINES AND DUCT BURNERS (3 EACH0	NATURAL GAS	1030	MW (TOTAL)	Sulfur Dioxide (SO2)	FUEL SWEET, NATURAL GAS WITH NO MORE THAN 5.0 GRAINS (HOURLY AVERAGE) AND 0.2 GRAIN TOTAL S PER 100 DSCF (ANNUALLY)	13.6	LB/H	0			
TX-0386	AMELLA ENERGY CENTER	TX	03/26/2002 ACT	AUXILIARY BOILER	NATURAL GAS	155	MMBTU/H	Sulfur Dioxide (SO2)		0 843	LB/H	0.005	LB/MMBTU		
TX-0414	ATOFINA PETROCHEMICALS PORT ARTHUR COMPLEX	TX	04/22/1999 ACT	TURBINE, COMBINED CYCLE, W/ SCR, UNIT 2	NATURAL GAS	39	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	2.27	LB/H	0			
TX-0414	ATOFINA PETROCHEMICALS PORT ARTHUR COMPLEX	TX	04/22/1999 ACT	SUPPLEMENTAL BOILER	NATURAL GAS	227	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.61	LB/H	0.0027	LB/MMBTU	CALCULATED	

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas > 100 million BTU/hr & < 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0414	ATOFINA PETROCHEMICALS PORT ARTHUR COMPLEX	TX	04/22/1999 ACT	TURBINE, COMBINED CYCLE & DUCT BURNER, UNIT 1	NATURAL GAS	39	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	2.27	LB/H	0			
TX-0499	SANDY CREEK ENERGY STATION	TX	07/24/2006 ACT	PULVERIZED CAOL BOILER	COAL	8185	MMBTU/H	Sulfur Dioxide (SO2)		2456	LB/H	0			
TX-0499	SANDY CREEK ENERGY STATION	TX	07/24/2006 ACT	AUXILLARY BOILER	NATURAL GAS	175	MMBTU/H	Sulfur Dioxide (SO2)		0.11	LB/H	0			
TX-0499	SANDY CREEK ENERGY STATION	TX	07/24/2006 ACT	PLANT-EMISSION CAP				Sulfur Dioxide (SO2)		3585	T/YR	0			
VA-0270	VCU EAST PLANT	VA	03/31/2003 EST	BOILER - NO 6 FUEL OIL	FUEL OIL #6	150	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	78.5	LB/H	0 52	LB/MMBTU		
VA-0270	VCU EAST PLANT	VA	03/31/2003 EST	BOILER NATUAL GAS	NATURAL GAS	150	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	0.1	LB/H	0.001	LB/MMBTU		
VA-0270	VCU EAST PLANT	VA	03/31/2003 EST	BOILER - DISTILLATE	FUEL OIL #2	150	MMBTU	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	78.5	LB/H	0 53	LB/MMBTU		
VA-0270	VCU EAST PLANT	VA	03/31/2003 EST	BOILER - OIL OR GAS	GAS OR OIL	150	MMBTU	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES. LOW SULFUR FUELS.	196.3	T/YR	0		NOT AVAILABLE	
VA-0278	VCU EAST PLANT	VA	03/31/2003 ACT	BOILER, NATURAL GAS, (3)	NATURAL GAS	150.6	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.1	LB/H	0.0007	LB/MMBTU	calculated	
VA-0278	VCU EAST PLANT	VA	03/31/2003 ACT	BOILER, #6 FUEL OIL, (3)	# 6 FUEL OIL	150.6	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR LIMIT: < 0.5% S BY WT	78.5	LB/H	0 52	LB/MMBTU	calculated	
VA-0278	VCU EAST PLANT	VA	03/31/2003 ACT	BOILER, #2 FUEL OIL, (3)	NO. 2 FUEL OIL	150.6	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR LIMITS: <0.5% S BY WT.	78.5	LB/H	0.5	LB/MMBTU	calculated	
WI-0228	WPS - WESTON PLANT	WI	10/19/2004 ACT	AUXILLIARY NAT. GAS FIRED BOILER (B25, S25)	NATURAL GAS	229.8	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS	0.0006	LB/MMBTU	0			
WI-0228	WPS - WESTON PLANT	WI	10/19/2004 ACT	DIESEL BOOSTER PUMP (B27, S27)	DIESEL FUEL OIL	265	HP	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMIT (0 003 WT. % S) GOOD COMBUSTION PRACTICES	0.54	LB/H	0			'ULTRA LOW SULFUR DIESEL FUEL'
WI-0228	WPS - WESTON PLANT	WI	10/19/2004 ACT	MAIN FIRE PUMP (DIESEL ENGINE)	DIESEL FUEL OIL	460	HP	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES, ULTRA LOW SULFUR (0.003 WT. % S) DIESEL FUEL OIL	0.94	LB/H	0			
WI-0228	WPS - WESTON PLANT	WI	10/19/2004 ACT	B63, S63; B64, S64 - NATURAL GAS STATION HEATER 1 AND 2	NATURAL GAS	0.75	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS	0.0004	LB/H	0		NOT AVAILABLE	(LIMIT IS FOR EACH UNIT)
WI-0228	WPS - WESTON PLANT	WI	10/19/2004 ACT	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	5173 07	MMBTU/H	Sulfur Dioxide (SO2)	DRY FGD, LIMIT ON EMISSIONS ENTERING CONTROL SYSTEM: 1.23 LBS/MMBTU 30 DAY AVG.	0.1	LB/MMBTU	0			POLLUTANT LIMITS INCLUDE STARTUP / SHUTDOWN AND ATOMIZER CHANGEOUT. PERMITTEE MAY ONLY USE ACTUAL HOURS OF OPERATION WHEN DETERMINING TIME AVERAGED EMISSIONS. WHEN CONDUCTING MAINTENANCE ON CONTROL SYSTEM (ROUTINE ATOMIZER CHANGEOUT): 3491 8 POUNDS PER HOUR ON A 3-HOUR AVERAGE AND 1508.9 POUNDS PER HOUR ON A 24-HOUR AVERAGE. CONTROLLED EMISSIONS: SULFUR DIOXIDE EMISSIONS SHALL BE LIMITED TO 621 POUNDS PER HOUR AVERAGED OVER ANY CONSECUTIVE 3-HOUR PERIOD AND SULFUR DIOXIDE EMISSIONS SHALL BE LIMITED TO 589 POUNDS PER HOUR AVERAGED OVER ANY CONSECUTIVE 24-HOUR PERIOD
WV-0023	MAIDSVILLE	WV	03/02/2004 ACT	BOILER, PC	PULVERIZED COAL	6114	MMBTU/H	Sulfur Dioxide (SO2)	WET LIMESTONE FORCED OXIDATION	917	LB/H	0.15	LB/MMBTU	3 HOUR ROLLING	IN SETTLEMENT AGREEMENT OF APPEAL NO. 04-03-AQB, EXHIBIT B HAS A SO2 LIMIT OF 0.095 LB/MMBU, WHICH WAS NOT AGREED BY THE WVDEP AND NOT CONSIDERED AS BACT.
WV-0023	MAIDSVILLE	WV	03/02/2004 ACT	AUXILIARY BOILER	NATURAL GAS	225	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR NATURAL GAS FUEL	0 004	LB/H	0			LIMITED TO USE OF NATURAL GAS AND 3,000 HOURS OF OPERATION PER YEAR
WV-0023	MAIDSVILLE	WV	03/02/2004 ACT	IC ENGINE, FIRE WATER PUMP	DIESEL	85	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT LIMITED TO 0.05% BY WEIGHT	3.3	LB/H	0			
WV-0023	MAIDSVILLE	WV	03/02/2004 ACT	EMERGENCY GENERATOR	DIESEL	1801	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT IN THE FUEL LIMITED TO 0 05% BY WEIGHT	6.5	LB/H	0			LIMITED TO 500 HOURS OF OPERATION A YEAR

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel > 100 million BTU/hr & < 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	DUCT BURNER FOR STEAM GENERATION, E-1410	NATURAL GAS*	36.5	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LIQUEFIED PETROLEUM GAS, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		500	PPM @ 15% O2	ASSUMED @ 15% O2	ESTIMATED EMISSIONS ARE 10.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	CRUDE HEATER, H101B	NATURAL GAS*	165	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S. GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED FOR SO2 AND H2S TOGETHER. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2. LIMITS ARE PROVIDED BASED ON FUEL CONTENT (SEE POLLUTION PREVENTION DESCRIPTION). ESTIMATED EMISSIONS ARE 21.7 T/YR, BUT THIS IS NOT A LIMIT. ADDITIONAL LIMIT IS A PRORATED CONCENTRATION OF THE FOLLOWING: 230 MG H2S/DSCF FOR EQUIPMENT FIRED ON REFINERY GAS, AND 500 PPM SO2 FOR EQUIPMENT NOT FIRED ON REFINERY GAS.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	POWERFORMER PREHEATER, H201	NATURAL GAS*	31.8	MMBTU/H	Sulfur Dioxide (SO2)	SOURCE WAS INSTALLED PRIOR TO 1975 SO IT IS NOT SUBJECT TO BACT-PSD.	0		0			ESTIMATED EMISSIONS ARE 4 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	POWERFORMER PREHEATER, H202	NATURAL GAS*	51	MMBTU/H	Sulfur Dioxide (SO2)	SOURCE IS NOT SUBJECT TO FUEL LIMITATIONS UNDER BACT-PSD BECAUSE IT WAS INSTALLED PRIOR TO 1975.	0		0			ESTIMATED EMISSIONS ARE 6.7 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	POWERFORMER PREHEATER, H203	NATURAL GAS*	27.9	MMBTU/H	Sulfur Dioxide (SO2)	SOURCE WAS INSTALLED PRIOR TO 1975 AND IS THEREFORE NOT SUBJECT TO PSD.	0		0			ESTIMATED EMISSIONS ARE 3.7 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	POWERFORMER REHEATER, H204	NATURAL GAS*	53.8	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR CONTENT FUEL LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR, NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR H2S AND SO2. ESTIMATED SO2 EMISSIONS ARE 7.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. ONLY EMISSION LIMITS PROVIDED ARE A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER THREE HOURS, AND 500 PPM SO2 AVERAGED OVER THREE HOURS. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	HYDROCRACKER RECYCLE GAS HEATER, H401	NATURAL GAS*	38.9	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR LIMITS AS FOLLOWS IS CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS COMBINED FOR SO2 AND H2S. ONLY EMISSION LIMITS PROVIDED ARE A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER THREE HOURS, AND 500 PPM SO2 AVERAGED OVER THREE HOURS. ESTIMATED SO2 EMISSIONS ARE 5.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	HYDROCRACKER RECYCLE GAS HEATER, H402	NATURAL GAS*	38	MMBTU/H	Sulfur Dioxide (SO2)	THE FOLLOWING FUEL SULFUR CONTENT LIMITS ARE CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS COMBINED FOR SO2 AND H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF THE FOLLOWING: 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2. ESTIMATED EMISSIONS OF SO2 ARE 5 0 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	SOL. CEN. GAS TURBINE (NG) & DUCT BURNER, GT/E1410	NATURAL GAS*	50.9	MMBTU/H	Sulfur Oxides (SOx)	THE FOLLOWING FUEL SULFUR CONTENT LIMITS ARE CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			ESTIMATED EMISSIONS ARE 10.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	SOL. CEN. GAS TURBINE (NG) & DUCT BURNER, GT/E1400	NATURAL GAS*	50.9	MMBTU/H	Sulfur Oxides (SOx)	THE FOLLOWING FUEL SULFUR CONTENT LIMITS ARE CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			ESTIMATED EMISSIONS ARE 10.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS SUBJECT TO NSPS FOR SO2.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel > 100 million BTU/hr & < 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	DUCT BURNER FOR STEAM GENERATION, E-1400	NATURAL GAS*	36.5	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		500	PPM @ 15% O2	ASSUMED 15% O2	ESTIMATED EMISSIONS WHEN BURNING LPG, NG, OR DIESEL, ARE 10.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	REFINERY FLARE, J 801	NATURAL GAS*	1	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUEFIED PETROLEUM GAS, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH FOR SO2 AND H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF THE FOLLOWING; 230 MB H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	ELECTRIC GENERATOR CAT 3412, EG704	DIESEL	4.8	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	STEWART-STEVENSON GENERATOR, EG801	DIESEL	6.1	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	NORTH CATERPILLAR, P605A	NATURAL GAS	5.6	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0.1 T/YR SO2, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	SOUTH CATERPILLAR, P605B	NATURAL GAS	830	HP	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	NORTH CUMMINS, P708A	DIESEL	290	HP	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	SOUTH CUMMINS, P708B	DIESEL	290	HP	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	UPPER TANK FARM CAT 3412DT, P708C	DIESEL	660	HP	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0 5 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	HOT OIL HEATER, H609	NATURAL GAS*	56	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED. SOURCE IS NOT SUBJECT TO BACT- PSD BECAUSE IT WAS INSTALLED PRIOR TO 1975.	0		0			ESTIMATED EMISSIONS ARE 7.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	HYDROGEN REFORMER FURNACE, H1001	NATURAL GAS*	152.3	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR SO2 AND H2S. EMISSIONS LIMITS ARE A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE 20 0 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel > 100 million BTU/hr & < 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	REACTION FURNACE BURNER, H1101	NATURAL GAS*	5.2	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER THREE HOURS AND 500 PPM SO2 AVERAGED OVER THREE HOURS. ESTIMATED SO2 EMISSIONS ARE 0.7 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	COOLING TOWER CAT, P719C	NATURAL GAS	1.1	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	SULFUR RECOVERY UNIT		19.3	LTPD	Sulfur Dioxide (SO2)	NONE INDICATED	0		0			ESTIMATED EMISSIONS ARE 14.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	TAIL GAS BURNER, H1105	NATURAL GAS*	2	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED SO2 EMISSIONS ARE 0 3 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	#4 REHEATER STARTUP BURNER, H1106	NATURAL GAS*	1.9	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	PRIP ABSORBER FEED FURNACE, H1201/1203	NATURAL GAS*	10.4	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR SO2 AND H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE 1.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	CRUDE HEATER, H101A	NATURAL GAS*	140	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED AS SOURCE WAS INSTALLED PRIOR TO 1975 AND IS NOT SUBJECT TO BACT-PSD.	0		0			SOURCE IS NOT SUBJECT TO PSD REQUIREMENTS BECAUSE IT WAS INSTALLED PRIOR TO 1975. ESTIMATED EMISSIONS ARE 18.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	POWERFORMER REHEATER, H205	NATURAL GAS*	48.8	MMBTU/H	Sulfur Dioxide (SO2)	A PRORATED CONCENTRATION OF THE FOLLOWING FUEL LIMITS IS CONSIDERED BACT: DIESEL FUEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			COMBINED EMISSIONS INFORMATION IS PROVIDED FOR SO2 AND H2S. ESTIMATED EMISSIONS OF SO2 ARE 6.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. ADDITIONAL EMISSION LIMITS ARE: A PRORATED CONCENTRATION OF THE FOLLOWING; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	HYDROCRACKER FRACTIONATER REBOILER, H403	NATURAL GAS*	50	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS COMBINED FOR SO2 AND H2S. ESTIMATED SO2 EMISSIONS ARE 6.6 T/YR. SOURCE IS ALSO SUBJECT TO NSPS. EMISSIONS LIMITS ARE A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	RESIDUAL OIL HEATER, H612	NATURAL GAS*	22.2	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT IS LIMITED AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION FOR SO2 AND H2S IS COMBINED. ESTIMATED SO2 EMISSIONS ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2. EMISSION LIMITS ARE A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	FIRED STEAM GENERATOR, H701	NATURAL GAS*	36 55	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED. THIS SOURCE IS NOT SUBJECT TO BACT-PSD AS IT WAS INSTALLED PRIOR TO 1975.	0		0			CONTROLS NOT INDICATED. ESTIMATED EMISSIONS ARE 4.8 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	FIRED STEAM GENERATOR, H702	NATURAL GAS*	36 55	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED. THIS SOURCE IS NOT SUBJECT TO BACT-PSD AS IT WAS INSTALLED PRIOR TO 1975.	0		0			ESTIMATED EMISSIONS ARE 4 8 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. EMISSION LIMITS, BASIS OF DETERMINATION, AND CONTROLS ARE NOT PROVIDED.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel > 100 million BTU/hr & < 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	NATURAL GAS SUPPLY HEATER, H704	NATURAL GAS*	2	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR EONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. ESTIMATED EMISSIONS OF SO2 ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	FIRED STEAM GENERATOR, H801	NATURAL GAS*	32	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 4 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	PRIP RECYCLER H2 FURNACE, H1202	NATURAL GAS*	11.2	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED SO2 EMISSIONS ARE 1 5 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	VACUUM TOWER HEATER, H1701	NATURAL GAS*	91	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE 12.0 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	HOT GLYCOL HEATER, H802	NATURAL GAS*	10.8	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS COMBINED FOR SO2 AND H2S. EMISSION LIMITS ARE A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER THREE HOURS AND 500 PPM SO2 AVERAGED OVER THREE HOURS. ESTIMATED EMISSIONS OF SO2 ARE 1.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	HYDROCRACKER STABILIZER REBOILER, H404	NATURAL GAS*	64.4	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR SO2 AND H2S. ESTIMATED SO2 EMISSIONS ARE 8.5 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS. EMISSION LIMITS ARE A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	#1 REHEATER STARTUP BURNER, H1102	NATURAL GAS*	1.65	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT IS LIMITED ACCORDING TO THE FOLLOWING: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% H2S; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR H2S AND SO2. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER THREE HOURS, AND 500 PPM SO2 AVERAGED OVER THREE HOURS. ESTIMATED SO2 EMISSIONS ARE 0.2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	#2 REHEATER STARTUP BURNER, H1103	NATURAL GAS*	1.15	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR H2S AND SO2. EMISSION LIMIT IS A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED SO2 EMISSIONS ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	#3 REHEATER STARTUP BURNER, H1104	NATURAL GAS*	1 05	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF THE FOLLOWING; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOUR. ESTIMATED EMISSIONS OF SO2 ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0074	ENDICOTT PRODUCTION FACILITY	AK	07/29/2011 ACT	Combustion of Fuel	Fuel Gas	43000	hp	Sulfur Dioxide (SO2)	Limit concentration of hydrogen sulfide in the fuel no more than 1,000 parts per million by volume	1000	PPMV	0			
AK-0074	ENDICOTT PRODUCTION FACILITY	AK	07/29/2011 ACT	Combustion	Fuel Gas	8717	hp	Sulfur Dioxide (SO2)	Concentration of hydrogen sulfide in fuel gas shall not excced 1,000 ppmv	1000	PPMV	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel > 100 million BTU/hr & < 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0074	ENDICOTT PRODUCTION FACILITY	AK	07/29/2011 ACT	Flares	Fuel gas	500	MMscf/day	Sulfur Dioxide (SO2)	Limit concentration of hydrogen sulfide in fuel gas to 1000 ppmv.	1000	PPMV	0			
AK-0074	ENDICOTT PRODUCTION FACILITY	AK	07/29/2011 ACT	Combustion	Fuel Gas	98	MMBTU/H	Sulfur Dioxide (SO2)	Limit content of hydrogen sulfide	1000	PPMV	0			
AK-0074	ENDICOTT PRODUCTION FACILITY	AK	07/29/2011 ACT	Combustion	Fuel Gas	5400	hp	Sulfur Dioxide (SO2)	Limit hydrogen sulfide in fuel gas to no more than 1000 ppmv	1000	PPMV	0			
AK-0077	NORTHSTAR PRODUCTION FACILITY	AK	06/26/2012 ACT	Fuel Gas Combustion by Burners	Fuel Gas	82	MMBTU/H	Sulfur Dioxide (SO2)	H2S content of fuel gas shall not exceed 300 ppmv at any time	300	PPMV	0			No costs associated because the Department determined Good Combustion Practices as BACT
AK-0077	NORTHSTAR PRODUCTION FACILITY	AK	06/26/2012 ACT	Combustion of Fuel Gas by ICEs	Fuel Gas	2180	kW	Sulfur Dioxide (SO2)	H2S content of fuel gas shall not exceed 300 ppmv at any time	300	PPMV	0			
AK-0077	NORTHSTAR PRODUCTION FACILITY	AK	06/26/2012 ACT	Combustion of Fuel Gas by Turbines < 25 MW	Fuel Gas	24	MW	Sulfur Dioxide (SO2)	H2S content of fuel gas shall not exceed 300 ppmv at any time	300	PPMV	0			
AK-0077	NORTHSTAR PRODUCTION FACILITY	AK	06/26/2012 ACT	Flaring of Fuel Gas	Fuel Gas	660	MMscf/yr	Sulfur Dioxide (SO2)	H2S content of fuel gas shall not exceed 300 ppmv at any time	300	PPMV	0			
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	DISTILLATE HYDROTREATER CHARGE HEATER	REFINERY FUEL GAS OR NATURAL GAS	25	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	DISTILLATE HYDROTREATER SPLITTER REBOILER	REFINERY FUEL GAS OR NATURAL GAS	117	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	TANK FARM THERMAL OXIDIZER	REFINERY FUEL GAS AND GASES FROM TANKS			Sulfur Dioxide (SO2)		35	PPMV	0			THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	WASTEWATER TREATMENT PLANT THERMAL OXIDIZER	NATURAL GAS OR REFINERY FUEL GAS			Sulfur Dioxide (SO2)	35 PPM SULFUR LIMIT IN FUEL.	35	PPMV	0			THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SULFER PIT NOS. 1 AND 2				Sulfur Dioxide (SO2)	ALL GASES DISCHARGED FROM THE SULFUR PITS MUST BE COLLECTED AND ROUTED TO THE FRONT OF EITHER SULFER RECOVERY UNIT 1 OR UNIT 2.	33.5	LB/H	0		NOT AVAILABLE	THE SULFUR LIMIT IS FOR ANY GASES FROM THE SULFUR RECOVERY PLANT.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	CATALYTIC REFORMING UNIT CHARGE HEATER	REFINERY FUEL GAS AND NATURAL GAS	122	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR LIMITED TO 35 PPM IN FUEL.	35	PPMV	0		NOT AVAILABLE	THE 35 PPMV SULFUR LIMIT, AS H2S, IS A RESTRICTION ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS BEING FIRED IN THE UNIT.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	TRUCK AND RAIL CAR LOADING RACK THERMAL OXIDIZERS	REFINERY FUEL GAS OR NATURAL GAS	12.3	MMBTU/H	Sulfur Dioxide (SO2)		35	PPMV	0			THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	CATALYTIC REFORMING UNIT INTERHEATER NO. 1	REFINERY FUEL GAS AND NATURAL GAS	192	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	35	PPMV	0		NOT AVAILABLE	THE 35 PPMV SULFUR LIMIT, AS H2S, IS A RESTRICTION ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS BEING FIRED IN THE UNIT.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	CATALYTIC REFORMING UNIT INTERHEATER NO. 2	REFINERY FUEL GAS OR NATURAL GAS	129	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	CATALYTIC REFORMING UNIT DEBUTANIZER REBOILER	REFINERY FUEL GAS OR NATURAL GAS	23.2	MMBTU/H	Sulfur Dioxide (SO2)	S LIMIT OF 35 PPM.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	BUTANE CONVERSION UNIT DEHYDROGENATION REACTOR CHARGE HEATER	REFINERY FUEL GAS OR NATURAL GAS	311	MMBTU/H	Sulfur Dioxide (SO2)	35 PPM SULFUR LIMIT ON FUEL BURNED.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	BUTANE CONVERSION UNIT DEHYDROGENATION REACTOR INTERHEATER	REFINERY FULE GAS OR NATURAL GAS	328	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR LIMIT OF 35 PPM IN FUEL BURNED.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	VACUUM CRUDE CHARGE HEATER	REFINERY FUEL GAS OR NG	101	MMBTU/H	Sulfur Dioxide (SO2)		35	PPMV	0		NOT AVAILABLE	THIS LIMIT IS FOR SULFUR, AS H2S, AND IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	HYDROCRACKER UNIT CHARGE HEATER	REFINERY FUEL GAS OR NG	70	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	35	PPMV	0		NOT AVAILABLE	THIS LIMIT FOR SULFUR, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	HYDROCRACKER UNIT MAIN FRACTIONATOR HEATER	REFINERY FUEL GAS OR NG	211	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	35	PPMV	0		NOT AVAILABLE	THIS LIMIT ON SULFUR, AS H2S, IS A RESTRICTION ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	NAPHTHA HYDROTREATER CHARGE HEATER	REFINERY FUEL GAS OR NG	21.4	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM	35	PPMV	0		NOT AVAILABLE	THIS LIMIT ON SULFUR, AS H2S, IS A RESTRICTION ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	BUTANE CONVERSION UNIT ISOSTRIPPER REBOILER	REFINERY FUEL GAS AND NATURAL GAS	222	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR LIMITED TO 35 PPM IN FUEL BURNED.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	ATMOSPHERIC CRUDE CHARGE HEATER	NATURAL GAS OR REFINERY FUEL GAS	346	MMBTU/H	Sulfur Dioxide (SO2)	35 PPM SULFUR LIMIT IN FUEL.	35	PPMV	0		NOT AVAILABLE	THE 35 PPMV SULFUR LIMIT, AS H2S, IS A RESTRICTION ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS BEING FIRED IN THE UNIT.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	HYDROGEN REFORMER HEATER	REFINERY FUEL GAS OR NATURAL GAS	1435	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SPRAY DRYER HEATER	REFINERY FUEL GAS OR NATURAL GAS	44	MMBTU/H	Sulfur Dioxide (SO2)		35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SULFUR RECOVERY UNITS 1 AND 2				Sulfur Dioxide (SO2)	ALL GASES DISCHARGED FROM THE SULFUR RECOVERY UNITS MUST BE COLLECTED AND ROUTED TO THE FRONT OF EITHER SULFER RECOVERY UNIT 1 OR UNIT 2.	33.5	LB/H	0		NOT AVAILABLE	THE SULFUR LIMIT IS FOR ANY GASES FROM THE SULFUR RECOVERY PLANT.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	TAIL GAS TREATMENT UNIT				Sulfur Dioxide (SO2)	ALL GASES DISCHARGED FROM THE TAIL GAS TREATMENT UNIT MUST BE ROUTED TO THE SULFUR RECOVERY PLANT THERMAL OXIDIZER	33.5	LB/H	0		NOT AVAILABLE	THE SULFUR LIMIT IS FOR ANY GASES FROM THE SULFUR RECOVERY PLANT.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SULFUR RECOVERY PLANT THERMAL OXIDIZER	REFINERY FUEL GAS OR NATURAL GAS	100	MMBTU/H	Sulfur, Total Reduced (TRS)		0 089	LB/H	0		NOT AVAILABLE	
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SULFUR RECOVERY PLANT THERMAL OXIDIZER	REFINERY FUEL GAS OR NATURAL GAS	100	MMBTU/H	Sulfur Dioxide (SO2)		33.5	LB/H	0		NOT AVAILABLE	THE SULFUR LIMIT IS FOR ANY GASES FROM THE SULFUR RECOVERY PLANT.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	DELAYED COKING UNIT CHARGE HEATER NOS. 1 AND 2	REFINERY FUEL GAS OR NATURAL GAS	99.5	MMBTU/H	Sulfur Dioxide (SO2)	FUEL LIMITED TO 35 PPM S.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
LA-0123	BATON ROUGE REFINERY	LA	04/26/2002 ACT	FRACTIONATOR FURNACE		360	MMBTU/H	Sulfur Dioxide (SO2)	USE OF CLEAN FUELS WITH A MAXIMUM SULFUR CONTENT LESS THAN 0.10 GR/DSCF (160 PPMV) H2S IN FUEL.	12.47	LB/H	0.035	LB/MMBTU	CALCULATED	
LA-0123	BATON ROUGE REFINERY	LA	04/26/2002 ACT	HYDROFINER FURNACE 1		150	MMBTU/H	Sulfur Dioxide (SO2)	USE OF CLEAN FUELS WITH A MAXIMUM SULFUR CONTENT OF LESS THAN 0.10 GR/DSCF (160 PPMV) H2S IN FUEL.	5.1	LB/H	0.034	LB/MMBTU	CALCULATED USING THROUGHPUT	EMISSION LIMIT 1 IS 5.10 LB/H.
LA-0123	BATON ROUGE REFINERY	LA	04/26/2002 ACT	HYDROFINER FURNACE 2		197	MMBTU/H	Sulfur Dioxide (SO2)	USE OF CLEAN FUELS WITH A MAXIMUM SULFUR CONTENT OF LESS THAN 0.10 GR/DSCF (160 PPMV) H2S IN FUEL.	6.93	LB/H	0.035	LB/MMBTU	CALCULATED USING THROUGHPUT	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	CRUDE HEATER (2)	NAT & REFINERY GAS	281.1	MMBTU/H (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	11.25	LB/H	0.0044	LB/MMBTU	EACH, CALCULATED	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	LGO HYDROCARBON CHARGE HEATER	NAT & REFINERY GAS	69.4	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	2.78	LB/H	0 04	LB/MMBTU	CALCULATED	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	LGO HYDROCARBON STRIPPER REBOILER		62.1	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	2.49	LB/H	0 04	LB/MMBTU	CALCULATED	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	DEASPHALTING HEATER	NAT & REFINERY GAS	221	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	8.85	LB/H	0 04	LB/MMBTU	CALCULATED	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	MARINE LOADING VAPOR COMBUSTOR		50000	BBL	Sulfur Dioxide (SO2)	NONE INDICATED	0.13	LB/H	0			
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	HGO HYDROCARBON CHARGE HEATER		98.8	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	3.95	LB/H	0 04	LB/MMBTU	CALCULATED	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	BOILER NO. 1	NAT & REFINERY GAS	350	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL	11.21	LB/H	0.032	LB/MMBTU		
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	HF ALKYLATION MAIN FRACTIONATOR REBOILER	NAT & REFINERY GAS	268.6	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	10.75	LB/H	0 04	LB/MMBTU	CALCULATED	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	HGO HYDROCARBON STRIPPER REBOILER	NAT & REFINERY GAS	78	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	3.13	LB/H	0 04	LB/MMBTU	CALCULATED	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	SULFUR RECOVERY UNIT #3				Sulfur Dioxide (SO2)	AMINE BASED SCRUBBER (CLAUS/MDEA) AND THERMAL OXIDIZER	56.86	LB/H	60	PPMV @ 0% EXCESS AIR	EMISSION CAP, SEE NOTES	SULFUR RECOVERY UNIT EMISSIONS FROM THERMAL OXIDIZERS #1, #2, AND #3 ARE CONTROLLED UNDER A CAP, TOTAL SO2 EMMISIONS NOT TO EXCEED 398.52 T/YR (60 PPMV)
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	SULFUR RECOVERY UNITS NO. 1 AND NO. 2				Sulfur Dioxide (SO2)	AMINE BASED SCRUBBER (CLAUS/MDEA)AND THERMAL OXIDIZER.	56.86	LB/H	60	PPMV @ 0% EXCESS AIR	EMISSION CAP, SEE NOTES	SULFUR RECOVERY UNIT EMISSIONS FROM THERMAL OXIDIZERS #1, #2, AND #3 ARE CONTROLLED UNDER A CAP, TOTAL SO2 EMMISIONS NOT TO EXCEED 398.52 T/YR (60 PPMV)
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	COKER HEATER		241.1	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL	9.64	LB/H	0 04	LB/MMBTU		
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	SULFUR PLANT NO. 3 FUGITIVES				Sulfur Dioxide (SO2)		0.07	LB/H	0			THERE IS AN EMISSION CAP FOR MAXIMUM SO2 EMISSIONS
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	PIPESTILL, COKER, HYDROCRACKING, & LIGHT ENDS FURNACES				Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0 034	LB/MMBTU	0.034	LB/MMBTU		
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	PIPESTILL, COKER, CAT COMPLEX, & LIGHT ENDS FURNACES				Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0 034	LB/MMBTU	0.034	LB/MMBTU		

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel > 100 million BTU/hr & < 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	REFORMING, HYDROFINING, & HEAVY CAT FURNACES				Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0 034	LB/MMBTU	0.034	LB/MMBTU		
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	FEED PREPARATION FURNACES F-30 & F-31		352	MMBTU/H	Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0.1778	LB/MMBTU	0.1778	LB/MMBTU		
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	CRU REGENERATOR VENT		329	UNITS/YR	Sulfur Dioxide (SO2)	GOOD ENGINEERING DESIGN AND PROPER OPERATION	0.88	LB/H	0			
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	POWERFORMING & LIGHT ENDS FURNACES				Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0.1778	LB/MMBTU	0.1778	LB/MMBTU		
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	POWERFORMING 2 & EAST LIGHT ENDS FURNACES				Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0.1778	LB/MMBTU	0.1778	LB/MMBTU		
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	NAPHTHA HYDROTREATER REACTOR CHARGE HEATER (5-08), KHT REACTOR CHARGE HEATER (9-08), & HCU TRAIN 1&2 REACTOR CHARGE HEATERS (11-08 & 12-08)	REFINERY FUEL GAS			Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV AS H2S	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	NAPHTHA HYDROTREATER STRIPPER REBOILER HEATER (6-08) & KHT STRIPPER REBOILER HEATER (10-08)	REFINERY FUEL GAS			Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV AS H2S	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	BOILER NO. 1 (16-08)	REFINERY FUEL GAS	525.7	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	SRU THERMAL OXIDIZER NOS. 1 & 2 (18-08 & 19-08)	NATURAL GAS	63.7	MM BTU/H EA.	Sulfur Dioxide (SO2)	SEE NOTES	93.41	PPMVD	0			OXYGEN ENRICHMENT AND SULFUR SHEDDING PROCEDURES WITH AUTOMATED CONTROLS WITHIN THE SRU; EXCESS SRU CAPACITY; DEGASSING THE LIQUID SULFUR PRODUCT UPSTREAM OF THE SULFUR PIT TO <= 15 PPMV H2S; RECYCLING SULFUR PIT VENTS TO THE SRU INLET; PROPER OPERATING PRACTICES FOR SOUR WATER STORAGE; OVERALL SULFUR CONVERSION EFFICIENCY OF 99.9%; THERMAL OXIDIZER CONVERSION EFFICIENCY OF 99.5%
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	EMERGENCY GENERATORS (DOCK & TANK FARM) (21-08 & 22-08)	DIESEL			Sulfur Dioxide (SO2)		0.02	MAX LB/H	0			USE OF DIESEL WITH A SULFUR CONTENT OF 15 PPMV OR LESS.
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	A & B CRUDE HEATERS (1-08 & 2-08) & COKER CHARGE HEATER (15-08)	REFINERY FUEL GAS			Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	HYDROGEN REFORMER FURNACE FLUE GAS VENT (48-08)	PURGE GAS	1412.5	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL GAS	25	PPMV AS H2S	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	PLATFORMER HEATER CELLS NO. 1-3 (7A-08, 7B-08, & 7C-08) & HCU FRACTIONATOR HEATER (13-08)	REFINERY FUEL GAS			Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV AS H2S	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	A & B VACUUM TOWER HEATERS (3-08 & 4-08)	REFINERY FUEL GAS	155.2	MMBTU/H EA.	Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	FCCU REGENERATOR VENT (86-74)				Sulfur Dioxide (SO2)	VENTURI WET GAS SCRUBBER W/ ADDITION OF CAUSTIC SOLUTION	25	PPMV@0%02	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	MARINE VAPOR COMBUSTOR (55-08) & MARINE LOADING VAPOR COMBUSTOR (107-90)		50000	BBL/H EA.	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60.18.	0		0			NO EMISSION LIMITS AVAILABLE
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	THERMAL DRYING UNIT HEATEC HEATER (124-1-91)	REFINERY FUEL GAS	9.6	MM BTU/H	Sulfur Dioxide (SO2)		0.2	MAX LB/H	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	HYDROGEN PLANT FLARE (52-08)	H2 PLANT FEED GAS	2472	MMBTU/H	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60.18	0.01	MAX LB/H	0			
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	STARTUPS/SHUTDOWNS - SRU				Sulfur Dioxide (SO2)	FOLLOW WRITTEN SOP, MINIMIZE DURATION AND FREQUENCY, PROPERLY DOCUMENT ALL SU/SD	0		0			NO EMISSION LIMITS AVAILABLE
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	BOILERS (94-43 & 94-45)	REFINERY FUEL GAS	354	MMBTU/H EA	Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE).	9.43	LB/H	0			
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	FLARE 1-5 (15-77, 12-81, 2004-5A, 2004-5B & 2005-38)				Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE) AS FUELS AT FLARE TIP.	0		0			NO EMISSION LIMITS AVAILABLE

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel > 100 million BTU/hr & < 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	SRU THERMAL OXIDIZERS (99-3, 99-4, 2005-39, 2007-4)		50	MMBTU/H	Sulfur Dioxide (SO2)	CONTROL DEVICE - COMPLY WITH 40 CFR 60 SUBPART J	250	PPMVD	0			
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	FCCU REGENERATOR (16-77)				Sulfur Oxides (SOx)	WET SCRUBBER	176.12	LB/H	50	PPMV	7 DAY ROLLING AVERAGE	
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	MVR THERMAL OXIDIZER NO. 1 (94-8)		240	MMBTU/H	Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE).	3.3	LB/H	0			
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	ARU FLARE (2008-36)	PROCESS FUEL GAS			Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR PROCESS FUEL GAS WITH H2S <= 10 PPMV (ANNUAL AVERAGE)	0		0			NO EMISSION LIMITS AVAILABLE
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	HEATERS/REBOILERS	REFINERY FUEL GAS			Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE).	0		0			NO EMISSION LIMITS
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	HEATERS (2008-1 - 2008-9)	PROCESS FUEL GAS			Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR PROCESS FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 10 PPMV (ANNUAL AVERAGE).	0		0			NO EMISSION LIMITS
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	MVR THERMAL OXIDIZER NO. 2 (2008-38)	REFINERY FUEL GAS	200	MMBTU/H	Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR PROCESS FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 10 PPMV (ANNUAL AVERAGE).	0.45	LB/H	0			
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	HEATERS (94-21 & 94-29)	REFINERY FUEL GAS			Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE).	0		0			NO EMISSION LIMITS AVAILABLE
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	CPF HEATER H-39-03 & H-39-02 (94-28 & 94-30)	REFINERY FUEL GAS			Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE).	0		0			NO EMISSION LIMITS
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	BOILERS (2008-10, 2008-11, 2008-40)	REFINERY FUEL GAS	715	MMBTU/H EA	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS AND/OR REFINERY FUEL GAS WITH H2S <= 100 PPMV (ANNUAL AVERAGE) OR PROCESS FUEL GAS WITH H2S <= 10 PPMV (ANNUAL AVERAGE)	0		0			NO EMISSION LIMITS AVAILABLE
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	DHT HEATERS (4-81, 5-81)	REFINERY FUEL GAS	70	MMBTU/H EA	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR REFINERY FUEL GAS WITH H2S <= 100 PPMV (ANNUAL AVERAGE)	0		0			NO EMISSION LIMITS AVAILABLE
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	HEATER F-72-703 (7-81)	REFINERY FUEL GAS	633	MMBTU/H	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR REFINERY FUEL GAS WITH H2S <= 100 PPMV (ANNUAL AVERAGE)	0		0			NO EMISSION LIMITS AVAILABLE
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	THERMAL OXIDIZERS (2008-32, 2008-33, 2008-34)	PROCESS FUEL GAS	15	MMBTU/H EA	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS AND PROCESS FUEL GAS WITH H2S <=10 PPMV (ANNUAL AVERAGE)	0		0			NO EMISSION LIMITS AVAILABLE
OK-0095	ARDMORE REFINERY	OK	09/03/2003 ACT	SULFUR RECOVERY UNIT		130	LT/D	Sulfur Dioxide (SO2)	SCOT UNIT	250	PPMDV @ 0% O2	250	PPMDV @ 0% O2		
OK-0095	ARDMORE REFINERY	OK	09/03/2003 ACT	HOT OIL HEATERS				Sulfur Dioxide (SO2)	LOW SULFUR FUEL	160	S02 PPMDV	0		see note	limit is fuel H2S content limit, no emission rate limit.
OK-0095	ARDMORE REFINERY	OK	09/03/2003 ACT	FUGITIVE EQUIPMENT LEAKS				Sulfur Dioxide (SO2)	LEAK DETECTION AND REPAIR	0		0			No emission rate limit, just leak detection and control.
PA-0231	UNITED REFINERY CO.	PA	10/09/2003 ACT	DELAYED COKER UNIT, HEATER	REFINERY GAS	116	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR REFINERY GAS	2.71	LB/H	0.023	LB/MMBTU	Calculated using heat input	Best available technology (BAT) review done.
PA-0231	UNITED REFINERY CO.	PA	10/09/2003 ACT	FCC FEED HYDROTREATER HEATER	REFINERY GAS	91	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR REFINERY GAS	2.44	LB/H	0.027	LB/MMBTU	Calculated using heat input	Best available technology (BAT) review done.
PA-0231	UNITED REFINERY CO.	PA	10/09/2003 ACT	HYDROGEN REFORMER UNIT	REFINERY GAS	344	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE	9.22	LB/H	0			Best available technology (BAT) review done.
PA-0231	UNITED REFINERY CO.	PA	10/09/2003 ACT	NORTH CRUDE HEATER	REFINERY GAS	147	MMBTU/H	Sulfur Dioxide (SO2)	USE OF DESULFURIZED REFINERY GAS	46.22	LB/H	0.3	LB/MMBTU	Calculated using heat input	Best available technology (BAT) review done.
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	FURNACE OF-01	ETHANE	300	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.27	LB/H	0.001	LB/MMBTU	CALCULATED USING THROUGHPUT	
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	DIESEL ENGINE, DIESELFW	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED	0.7	LB/H	0			
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	FLARE, FLAREX				Sulfur Dioxide (SO2)	NONE INDICATED	0.02	LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	FURNACE AF-01	ETHANE	350	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.6	LB/H	0.005	LB/MMBTU	CALCULATED USING THROUGHPUT	
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	FURNACE CF-01	ETHANE	350	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.6	LB/H	0.005	LB/MMBTU	CALCULATED USING THROUGHPUT	
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	FURNACE DF-01	ETHANE	350	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.6	LB/H	0.005	LB/MMBTU		
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	FURNACE EF-01	ETHANE	350	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.6	LB/H	0.005	LB/MMBTU	CALCULATED USING THROUGHPUT	
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	FURNACE QF-01	ETHANE	300	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.27	LB/H	0.001	LB/MMBTU	CALCULATED USING MAX THROUGHPUT	
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	FURNACE BF-01	ETHANE	339	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.6	LB/H	0.005	LB/MMBTU	CALCULATED USING THROUGHPUT	
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	SECONDARY FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.1	LB/H	0			
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	(6) FURNACES, XAF-01 THRU XFF-01	ETHANE	333	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.8	LB/H	0.005	LB/MMBTU	EACH, CALCULATED USING MAX THROUGHPUT	
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	FURNACE XGF-01	ETHANE	502	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	2.8	LB/H	0.006	LB/MMBTU	CALCULATED USING MAX THROUGHPUT	
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	EMERGENCY GENERATOR	DIESEL	156	H/YR	Sulfur Dioxide (SO2)	NONE INDICATED	1.2	LB/H	0			
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	(2) FURNACES, IF-01 & JF-01	ETHANE	341	MMBTU/H, MAXIMUM	Sulfur Dioxide (SO2)	NONE INDICATED	1.46	LB/H	0.004	LB/MMBTU	EACH, CALCULATED USING MAX THROUGHPUT	
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	DIESEL ENGINE, DIESEL1A	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED	0.8	LB/H	0			
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	DIESEL ENGINE, DIESEL4	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED	0.8	LB/H	0			
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	FURNACE FF-01	ETHANE	350	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.6	LB/H	0.005	LB/MMBTU	CALCULATED USING THROUGHPUT	
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	FURNACE GF-01	ETHANE	350	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.6	LB/H	0.005	LB/MMBTU	CALCULATED USING THROUGHPUT	
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	PRIMARY FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.1	LB/H	0			
TX-0339	BAYTOWN OLEFINS PLANT	TX	04/05/2001 ACT	FURNACE HF-01	ETHANE	238	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.1	LB/H	0.005	LB/MMBTU	CALCULATED USING MAX THROUGHPUT	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BOILER NO. 13		366 83	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	9.4	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BOILERS 14 AND 15	PETRO REFIN GAS	586	MMBTU/H EA	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	15.1	LB/H	0.025	LB/MMBTU	EACH, CALCULATED	

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel > 100 million BTU/hr & < 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BTU- NO 3 REACTOR FEED HEATER		58 95	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	1.5	LB/H	0.025	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BTU-NO.4 REACTOR FEED HEATER		49	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	1.3	LB/H	0.027	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BTU-REFORMATE STABILIZER REBOILER		54.77	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	1.4	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	ISOM II WEST REACTOR FEED HEATER		104 25	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	2.7	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	ISOM II COMBINATION SPLITTER HEATER		77.62	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	2	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	ISOM II XYLENE RERUN TOWER HEATER		83.7	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	2.2	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	ISOM II EAST REACTOR FEED HEATER		75	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	1.9	LB/H	0.025	LB/MMBTU	CALCULATED	

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel > 100 million BTU/hr & < 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	ORTHOXYLENE I HEATER		96 23	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR CONTENT FUEL: USE REFINERY FUEL GAS WITH NO MORE THAN 0.1 GR/DSCF H2S OR USE NATURAL GAS WITH NO MORE THAN 0 25 GR/100 DSCF H2S AND NO MORE THAN 5.0 GR/100 DSCF TOTAL S.	2.5	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	ORTHOXYLENE II HEATER		226.42	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR CONTENT FUEL: USE REFINERY FUEL GAS WITH NO MORE THAN 0.1 GR/DSCF H2S OR USE NATURAL GAS WITH NO MORE THAN 0 25 GR/100 DSCF H2S AND NO MORE THAN 5.0 GR/100 DSCF TOTAL S.	5.8	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BACKUP AIR COMPRESSOR ENGINES (1-5)				Sulfur Dioxide (SO2)	LOW SULFUR CONTENT FUEL: USE REFINERY FUEL GAS WITH NO MORE THAN 0.1 GR/DSCF H2S OR USE NATURAL GAS WITH NO MORE THAN 0 25 GR/100 DSCF H2S AND NO MORE THAN 5.0 GR/100 DSCF TOTAL S.	4.72	LB/H	0			
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BTU-NO. 1 REACTOR FEED HEATER		121.74	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	3.1	LB/H	0.025	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BTU-NO.2 REACTOR FEED HEATER		69.68	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	1.8	LB/H	0.025	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BENZENE STABILIZER HEATER	PETRO REFIN GAS	38 34	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	1	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BOILER NO. 12		245	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	6.3	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	TX	05/23/2000 ACT	NO. 1 HYDROTREATER REBOILER HEATER	REFINERY GAS	32.7	MMBTU/H	Sulfur Dioxide (SO2)		1.23	LB/H	0			
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	TX	05/23/2000 ACT	NO. 1 REFORMER CHARGE HEATER	REFINERY GAS	248	MMBTU/H	Sulfur Dioxide (SO2)		9.33	LB/H	0			
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	TX	05/23/2000 ACT	NO. 1 REFORMER STABILIZER REPOILER HEATER	REFINERY GAS	20	MMBTU/H	Sulfur Dioxide (SO2)		0.75	LB/H	0			
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	TX	05/23/2000 ACT	NO 1 INTERHEATER	REFINERY GAS	147.2	MMBTU/H	Sulfur Dioxide (SO2)		5.54	LB/H	0			
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	TX	05/23/2000 ACT	NO. 1 REBOILER STABILIZER REBOILER HEATER	REFINERY GAS	45.7	MMBTU/H	Sulfur Dioxide (SO2)		1.72	LB/H	0			
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	TX	05/23/2000 ACT	NO. 1 HYDROTREATER CHARGE HEATER	REFINERY GAS	63.4	MMBTU/H	Sulfur Dioxide (SO2)		2.39	LB/H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel > 100 million BTU/hr & < 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	SR- 3/4 INCINERATOR				Sulfur Dioxide (SO2)		300	PPMV	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	EAST PROPERTY FLARE				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	COKER FLARE				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	TWENTY ONE FURNACES	REFINERY FUEL GAS			Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	FOURTEEN HEATERS				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	DHT H2 HEATER	HYDROGEN			Sulfur Dioxide (SO2)		300	PPMV	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	CO BOILER	CARBON MONOXIDE			Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	CCU FLARE				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	FOUR TAIL GAS INCINERATORS				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	WEST PROPERTY FLARE				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	THREE FLARES				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	ANALYZER				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	PYROLYSIS FURNACE (1010B)	FUEL GAS	250	MMBtu/H	Sulfur Dioxide (SO2)		0.41	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	PYROLYSIS FURNACES (1001-1008, 1009 B)	FUEL GAS	250	MMBtu/h	Sulfur Dioxide (SO2)		0.38	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	REBOILER (1 AND 2)	FUEL GAS	250	MMBtu	Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	FLARE				Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	DIESEL EMERGENCY GENERATOR				Sulfur Dioxide (SO2)		2.06	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	PYROLYSIS FURNACE (1054-1056)	FUEL GAS	250	mmbtu/h	Sulfur Dioxide (SO2)		0.38	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	PYROLYSIS FURNACE (1057-1062, 1091)	FUEL GAS	250	MMBTU/h	Sulfur Dioxide (SO2)		0.38	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	PYROLYSIS FURNACE (N1011-1012)		250	MMBTU/H	Sulfur Dioxide (SO2)		0.41	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	FLARE (1067)				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	FLARE (1087)				Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	DIESEL EMERGENCY GENERATOR (N7900LJD)	DIESEL			Sulfur Dioxide (SO2)		1.85	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	REGENERATION HEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	SECOND STAGE FEED HEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	FLARE (8003B)				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	DHT STRIPPER REBOILER	REFINERY FUEL GAS			Sulfur Dioxide (SO2)		1.9	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	COKER HEATER		291	MMBUT/H	Sulfur Dioxide (SO2)		6.6	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER		62	MMBTU/H	Sulfur Dioxide (SO2)		1.4	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	ACID GAS FLARE				Sulfur Dioxide (SO2)		0.2	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	NO.3 BOILER	REFINERY FUEL GAS	99	MMBTU/H	Sulfur Dioxide (SO2)		2.2	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	TAIL GAS INCINERATOR		100	MMBTU/H	Sulfur Dioxide (SO2)		22.4	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER REBOILER HEATER	REFINERY FUEL GAS	82	MMBTU/H	Sulfur Dioxide (SO2)		5.7	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	SOUR WATER STRIPPER FLARE				Sulfur Dioxide (SO2)		0.19	LB/H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel > 100 million BTU/hr & < 250 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	FLARE-COKE DRUM BLOWDOWN				Sulfur Dioxide (SO2)		1056	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	DHT CHARGER HEATER				Sulfur Dioxide (SO2)		2.1	LB/H	0			
TX-0492	VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	TX	05/05/2005 ACT	AJAX DPC-115 COMPRESSOR ENGINE	GAS	0.75	LTPD	Sulfur Dioxide (SO2)	LOWERED THROUGHPUT	0.01	LB/H	0			
TX-0492	VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	TX	05/05/2005 ACT	3 AJAX DPC-360LE COMPRESSOR ENGINES		0.75	LTPD	Sulfur Dioxide (SO2)	LOWER THROUGHPUT	0.01	LB/H	0			
TX-0492	VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	TX	05/05/2005 ACT	1.8 MMBTU AMINE REBOILER	SWEET NATURAL GAS	1.8	MMBTU	Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0492	VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	TX	05/05/2005 ACT	1.0 MMBTU DEHY REBOILER	SWEET NATURAL GAS	1	MMBtu	Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0492	VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	TX	05/05/2005 ACT	FACILITY FLARE-AMINE UNIT STILL VENT	SWEET NATURAL GAS	0.75	LTPD	Sulfur Dioxide (SO2)		140.5	LB/H	0			
TX-0496	INEOS CHOCOLATE BAYOU FACILITY	TX	08/29/2006 ACT	FURNACE EMISSION CAPS				Sulfur Dioxide (SO2)		61.37	LB/H	0			
TX-0580	MCKEE REFINERY HYDROGEN PRODUCTION UNIT	TX	12/30/2010 ACT	Hydrogen Production Unit Furnace	Refinery gas (PSA purge gas) w/NG	355.65	MMBTU/H	Sulfur Dioxide (SO2)	Sulfur content of the fuel used in the furnace is limited to 5 grains/100dscf on an annual average basis	0		0			
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	BSI Heater	Refinery Fuel Gas	50	MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0			
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	Emergency Air Compressor	Ultra Low Sulfur Diesel	400	hp	Sulfur Dioxide (SO2)	Ultra Low Sulfur Diesel	0		0			
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	581 Crude Heater	Refinery Fuel Gas	233	MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0			
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	583 Vacuum Heater	Refinery Fuel Gas	64.2	MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0			
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	Naphtha Splitter Heater	Refinery Fuel Gas	46.3	MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0			
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	Hydrocracker H5 Heater	Refinery Fuel Gas	44.9	MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0			
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	#1 HDS Heater	Refinery Fuel Gas	33.4	MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISCELLANEOUS IC ENGINES, 940 HP	DIESEL	940	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	0			BACT: FUEL SULFUR CONTENT LIMITS STATE: EMISSION LIMIT 1 AND HYDROGEN SULFIDE CONTENT RESTRICTIONS TO THE FUEL.
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	CAMP GENERATOR, UNIT 6,7	DIESEL	2362	KW	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	0			BACT-OTHER: FUEL SULFUR CONTENT LIMIT 18 AAC 50.055: EMISSION LIMIT 1
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	RIG ENGINES, UNIT 211, 212	DIESEL	1215	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	0		0			
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	BALL MILL, UNIT NO. 213		15	T/H	Sulfur Dioxide (SO2)	USE ONLY NATURAL GAS FUEL WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 50 PPM AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%.	500	PPM	0			STATE STANDARD 18 AAC 50 055.
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISCELLANEOUS IC ENGINES, 4240 HP	DIESEL	4240	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	0			BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1 AND SULFUR CONTENT RESTRICTION TO THE FUEL.
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	HEATERS, 35 0 MMBTU/H	DIESEL	35	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	2.71	LB/MMBTU	CALCULATED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1 AND SULFUR CONTENT RESTRICTION TO THE FUEL.
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISCELLANEOUS IC ENGINES, 949 HP	DIESEL	949	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	0			BACT: FUEL SULFUR CONTENT LIMITS STATE: EMISSION LIMIT 1 AND SULFUR CONTENT RESTRICTION TO THE FUEL.
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	HEATERS, 2.0 MMBTU/H	DIESEL	2	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	2.71	LB/MMBTU	CALCULATED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMITS STATE: EMISSION LIMIT 1 AND SULFUR CONTENT RESTRICTION TO THE FUEL.
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISCELLANEOUS IC ENGINES, 1200 HP	DIESEL	1200	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	0			BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISCELLANEOUS IC ENGINES, 500 HP	DIESEL	500	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	0			BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1 AND SULFUR CONTENT RESTRICTION TO THE FUEL.
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	HEATERS, 20 0 MMBTU/H	DIESEL	20	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	2.71	LB/MMBTU	CALCULATED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1 AND SULFUR CONTENT RESTRICTION TO THE FUEL.
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISCELLANEOUS HEATERS	DIESEL	13	MMBTU/H	Sulfur Dioxide (SO2)	TO ENSURE COMPLIANCE WITH THE EMISSION LIMIT, THE SULFUR CONTENT OF THE FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	2.71	LB/MMBTU	CALCULATED FROM 500 PPM	
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	CRANE, UNIT NO. 100	DIESEL	250	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	0		0			NO EMISSION LIMITS PROVIDED.
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	LIGHT PLANT, UNIT NO. 101	DIESEL	12.1	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	0		0			NO EMISSION LIMITS PROVIDED
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	SNOWBLOWER, UNIT NO. 102, 103	DIESEL	15	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT	0		0			NO EMISSION LIMITS PROVIDED.
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	SPACE HEATER, WAREHOUSE, UNIT NO. 15, 16	NATURAL GAS	0.5	MMBTU/H	Sulfur Dioxide (SO2)	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV.	500	PPM	2 55	LB/MMBTU	CALCULATED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISCELLANEOUS IC ENGINES, 2195 HP	DIESEL	2195	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	0			BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1 AND SULFUR CONTENT RESTRICTION TO THE FUEL.
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISCELLANEOUS IC ENGINES, 961.2 MMBTU/H	DIESEL	961.2	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	0			BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1 AND SULFUR CONTENT RESTRICTIONS TO THE FUEL
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISCELLANEOUS IC ENGINES, 3632 HP	DIESEL	3632	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	0			BACT: FUEL SULFUR CONTENT LIMITS STATE: EMISSION LIMIT 1 AND SULFUR CONTENT RESTRICTION TO THE FUEL.
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	TURBINE (GENERATOR), UNIT 3-5	NATURAL GAS	11892	KW	Sulfur Dioxide (SO2)	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV	150	PPM	0			COMPLY WITH THE NSPS EMISSION LIMITS BY THE CONTROL METHOD DESCRIBED

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	HEATERS, 4.0 MMBTU/H	DIESEL	4	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	2.71	LB/MMBTU	CONVERTED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1 AND SULFUR CONTENT RESTRICTION TO THE FUEL
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISCELLANEOUS IC ENGINES, 4425 HP	DIESEL	4425	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	0			BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1 AND SULFUR CONTENT RESTRICTION TO THE FUEL
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISC. IC ENGINES 950 HP	DIESEL	950	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	0		0			
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISC. IC ENGINES > 600 HP	DIESEL	650	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	0		0			
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	HEATER (NATURAL GAS), UNIT 210	NATURAL GAS	4.2	MMBTU/H	Sulfur Dioxide (SO2)	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV.	500	PPM	2 55	LB/MMBTU	CALCULATED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1 AND SULFUR CONTENT RESTRICTION TO FUEL
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	SPACE HEATER, WAREHOUSE, UNIT NO. 17	NATURAL GAS	0.63	MMBTU/H	Sulfur Dioxide (SO2)	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV.	500	PPM	2 55	LB/MMBTU	CALCULATED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMITS STATE: EMISSION LIMIT NO. 1
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	SPACE HEATER, WAREHOUSE, UNIT NO. 18	NATURAL GAS	1 06	MMBTU/H	Sulfur Dioxide (SO2)	HYDROGEN SULFIDE CONTENT OF NATURAL GAS SHALL NOT EXCEED 50 PPMV.	500	PPM	2 55	LB/MMBTU	CALCULATED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	RIG BOILER (NATURAL GAS), UNIT 206, 207	NATURAL GAS	6.3	MMBTU/H	Sulfur Dioxide (SO2)	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV	500	PPM	2 55	LB/MMBTU	CALCULATED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1 PLUS FUEL RESTRICTIONS
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	RIG BOILER, DIESEL, UNIT 206, 207	DIESEL	6.3	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	2.71	LB/MMBTU	CALCULATED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1 AND FUEL RESTRICTION
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	HEATER (NATURAL GAS), UNIT 208, 209	NATURAL GAS	3.5	MMBTU/H	Sulfur Dioxide (SO2)	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV.	500	PPM	2 55	LB/MMBTU	CALCULATED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1 AND SULFUR RESTRICTION TO THE FUEL
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISC. TURBINES, 6200 HP	DIESEL	6200	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	0		0			
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	HEATER (DIESEL), UNIT 210	DIESEL	4.2	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	2.71	LB/MMBTU	CALCULATED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMITS STATE: EMISSION LIMIT 1 AND SULFUR CONTENT LIMIT TO FUEL
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	HEATER (DIESEL), UNIT 208, 209	DIESEL	3.5	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT	500	PPM	2.71	LB/MMBTU	CALCULATED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1 AND SULFUR RESTRICTION TO FUEL
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	INCINERATOR, UNIT 9	NATURAL GAS*	1.6	MMBTU/H**	Sulfur Dioxide (SO2)	USE DIESEL FUEL OIL WITH SULFUR CONTENT =<0.15% OR NATURAL GAS WITH HYDROGEN SULFIDE CONTENT =<50 PPM	0		0			
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	WASTE HEAT RECOVERY, UNIT 10	NATURAL GAS	52.8	MMBTU/H	Sulfur Dioxide (SO2)	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV.	500	PPM	2 55	LB/MMBTU	CONVERTED FROM 500 PPM	
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	HP FLARE, UNIT NO 11	PRODUCED GAS*	0 08	MMSCF/D**	Sulfur Dioxide (SO2)	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV.	500	PPM	0			BACT-OTHER: FUEL SULFUR CONTENT LIMITS. STATE: EMISSION LIMIT 1
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	LP FLARE (NATURAL GAS), UNIT 12	NATURAL GAS	0 02	MMSCF/D	Sulfur Dioxide (SO2)	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV.	500	PPM	0			BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	LP FLARE (PRODUCED GAS), UNIT 12	PRODUCED GAS	0.43	MMSCF/D	Sulfur Dioxide (SO2)	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV AND SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	0			BACT- FUEL SULFUR CONTENT LIMIT STATE- EMISSION LIMIT 1
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	FIRE WATER PUMP, UNIT 8	DIESEL	755	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT	500	PPM	0			ENSURE THE EMISSION LIMIT BY COMPLYING WITH THE FUEL RESTRICTION 18 AAC 50.055: EMISSION LIMIT 1
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	MISC. IC ENGINES < 200 HP	DIESEL	170	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	0		0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	PORTABLE HEATER, UNIT NO. 105-107	DIESEL	1	MMBTU/H	Sulfur Dioxide (SO2)	ENSURE THE EMISSION LIMIT IS MET BY USING FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15% BY WEIGHT.	500	PPM	2.71	LB/MMBTU	CALCULATED FROM 500 PPM	
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	GLYCOL REBOILER, UNIT 13	NATURAL GAS	5	MMBTU/H	Sulfur Dioxide (SO2)	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV.	500	PPM	2 55	LB/MMBTU	CONVERTED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMIT. STATE: EMISSION LIMIT 1
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	GLYCOL SKID HEATER (NATURAL GAS), UNIT NO. 14	NATURAL GAS	1 05	MMBTU/H	Sulfur Dioxide (SO2)	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV.	500	PPM	2 55	LB/MMBTU	CALCULATED FROM 500 PPM	BACT: FUEL SULFUR CONTENT LIMIT STATE: EMISSION LIMIT 1
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	WELDER, UNIT NO. 104	DIESEL	38.2	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	0		0			NO EMISSION LIMITS PROVIDED.
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	TURBINE (COMPRESSOR), UNIT 1, 2	NATURAL GAS	32715	HP	Sulfur Dioxide (SO2)	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV.	150	PPM	0			COMPLY WITH NSPS LIMITS LISTED AS 1 & 2 BY THE CONTROL METHOD LISTED.
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	PORTABLE HEATER (BLOWER ENGINE), UNIT NO. 105-107	DIESEL	22	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15%.	500	PPM	0			BACT: FUEL SULFUR CONTENT LIMITS. STATE: EMISSION LIMIT NO. 1
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	RIG ENGINES, CATERPILLAR G399, UNIT 200-204	NATURAL GAS	930	HP	Sulfur Dioxide (SO2)	HYDROGEN SULFIDE CONTENT OF NATURAL GAS FUEL SHALL NOT EXCEED 50 PPMV	0		0			
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	COLD START UNIT, UNIT NO. 205	DIESEL	314	HP	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	0		0			
AK-0038	NORTHSTAR DEVELOPMENT PROJECT	AK	02/05/1999 ACT	GLYCOL SKID HEATER (DIESEL), UNIT NO. 14	DIESEL	1 05	LB/MMBTU	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.15% BY WEIGHT.	500	PPM	2.71	LB/MMBTU	CALCULATED FROM 500 PPM	BACT: FUEL SULFUR LIMIT STATE: EMISSION LIMIT 1
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	DRILLING BOILER NO. 1	NATURAL GAS	100	HP	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500	PPM	0.033	LB/MMBTU	CALCULATED	BASIS OF DETERMINATION- 18 AAC 50.055(C). THE HOURLY EMISSION LIMIT WAS CONVERTED INTO STANDARDIZED UNITS BY DIVIDING IT BY THE THROUGHPUT.
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	CATERPILLAR D-398 ENGINES NO. 1 AND 2	DIESEL	500	KW EACH	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT	500	PPM	0			LIMIT SET ACCORDING TO 18 AAC 50.055(C)
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	MANITOWOC CRANE ENGINE	DIESEL	175	HP	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT AND LIMITED HOURS OF OPERATION TO 1250 H/12-MO PERIOD, TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	UNIT CRANE ENGINE	DIESEL	90	HP	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT, AND LIMITED OPERATION TO 1250 H/12-MO PERIOD, TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	FIREWATER ENGINE NOS. 1 AND 2	DIESEL	250	HP EACH	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500	PPM	0			BASIS OF DETERMINATION- 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT AND TO LIMIT OPERATION TO A COMBINED USE NOT TO EXCEED 300 H/12-MO PERIOD, TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	HP FLARE PILOT	NATURAL GAS	0.13	MMBTU/H	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	HP SAFETY FLARE	NATURAL GAS	583.3	MMBTU/H	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT. THE OWNER WILL ALSO LIMIT NATURAL GAS CONSUMPTION FOR THE HP SAFETY FLARE, LP SAFETY FLARE, AND TEMPORARY FLARE TO A COMBINED THROUGHPUT NOT TO EXCEED 252 MMSCF/12-MO PERIOD.
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	LP SAFETY FLARE	NATURAL GAS	53.3	MMBTU/H	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT. THE OWNER WILL ALSO LIMIT NATURAL GAS CONSUMPTION FOR THE HP SAFETY FLARE, LP SAFETY FLARE, AND TEMPORARY FLARE, TO A COMBINED THROUGHPUT NOT TO EXCEED 252 MMSCF/12-MO PERIOD.
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	TEMPORARY FLARE	NATURAL GAS	833.3	MMBTU/H	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT. THE OWNER WILL ALSO LIMIT NATURAL GAS CONSUMPTION FOR THE HP SAFETY FLARE, LP SAFETY FLARE, AND TEMPORARY FLARE, TO A COMBINED THROUGHPUT NOT TO EXCEED 252 MMSCF/12-MO PERIOD.
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	TURBINE COMPRESSOR NO. 2	NATURAL GAS	4700	HP	Sulfur Dioxide (SO2)	BURN GASEOUS FUEL WITH A HYDROGEN SULFIDE CONTENT < 200 PPM.	150	PPM	0			ADDITIONAL EMISSION LIMIT BASED ON SIP, 18 AAC 50 055(C); 500 PPM OVER A 3 H AV. THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT. THE OWNER WILL ALSO LIMIT NATURAL GAS CONSUMPTION FOR TURBINES NO. 1 AND 2 TO A COMBINED USE NOT TO EXCEED 805 MMSCF/12-MO PERIOD.

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AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	GLYCOL HEATER NOS. 1, 2, AND 3	NATURAL GAS	8 36	MMBTU/H	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500	PPM	0.033	LB/MMBTU	EACH, CALCULATED	BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE HOURLY EMISSION LIMIT WAS CONVERTED INTO STANDARDIZED UNITS BY DIVIDING IT BY THE THROUGHPUT. THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT. THE OWNER WILL ALSO LIMIT NATURAL GAS CONSUMPTION FOR GLYCOL HEATERS NO. 1, 2, AND 3 TO A COMBINED USE NOT TO EXCEED 63 MMSCF/12-MO PERIOD.
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	TURBINE COMPRESSOR NO. 4	NATURAL GAS	6749	HP	Sulfur Dioxide (SO2)	BURN GASEOUS FUEL WITH A HYDROGEN SULFIDE CONTENT < 200 PPM.	150	PPM	0			ADDITIONAL EMISSION LIMIT BASED ON SIP, 18 AAC 50 055(C); 500 PPM AV OVER 3 H. THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	ENGINE NO. 1	NATURAL GAS	500	KW	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500	PPM	0			BASIS OF DETERMINATION- 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	ENGINE NO. 4	NATURAL GAS	500	KW	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500	PPM	0			BASIS OF DETERMINATION- 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	TURBINE COMPRESSOR NO. 1	NATURAL GAS	4700	HP	Sulfur Dioxide (SO2)	BURN GASEOUS FUEL WITH A HYDROGEN SULFIDE CONTENT < 200 PPM.	150	PPM	0			ADDITIONAL EMISSION LIMIT BASED ON SIP, 18 AAC 50 055(C); 500 PPM OVER A 3 H AV. THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT. THE OWNER WILL ALSO LIMIT NATURAL GAS CONSUMPTION FOR TURBINES NO. 1 AND 2 TO A COMBINED USE NOT TO EXCEED 805 MMSCF/12-MO PERIOD.
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	TURBINE COMPRESSOR NO. 3	NATURAL GAS	6749	HP	Sulfur Dioxide (SO2)	BURN GASEOUS FUEL WITH A HYDROGEN SULFIDE CONTENT < 200 PPM.	150	PPM	0			ADDITIONAL EMISSION LIMIT BASED ON SIP, 18 AAC 50 055(C); 500 PPM AV OVER 3 H. THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.
AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	JOHN DEERE 4039 ENGINE	DIESEL	78	HP	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT AND TO LIMIT OPERATION TO 350 H/12-MO PERIOD, TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.

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AK-0045	NORTH COOK INLET UNIT	AK	06/06/2000 ACT	GLYCOL REGENERATOR NOS. 1, 2, AND 3	NATURAL GAS	0 28	MMBTU/H EACH	Sulfur Dioxide (SO2)	USE NATURAL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.25% BY WEIGHT.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50.055(C). THE OWNER REQUESTED TO LIMIT THE SULFUR CONTENT OF GASEOUS AND LIQUID FUELS TO 200-PPM HYDROGEN SULFIDE AND 0.25% SULFUR BY WEIGHT TO AVOID A PSD PRE-CONSTRUCTION REVIEW OF EXISTING EQUIPMENT.
AK-0047	MILNE POINT PRODUCTION FACILITY	AK	07/13/2001 ACT	ENGINES (2), PU-0110A AND PU-0110B	DIESEL	187	HP	Sulfur Dioxide (SO2)	BURN FUEL OIL WITH NO GREATER THAN 0 30 % SULFUR BY WEIGHT.	500	PPM	2 56	LB/MMBTU	CALCULATED, ASSUMING PPM @15% O2	
AK-0047	MILNE POINT PRODUCTION FACILITY	AK	07/13/2001 ACT	FLARE	NATURAL GAS	83	MMSCF/D	Sulfur Dioxide (SO2)	BURN FUEL OIL WITH NO GREATER THAN 0 3% SULFUR BY WEIGHT AND NATURAL GAS WITH NO GREATER THAN 100 PPMVD H2S.	500	PPM	0			
AK-0047	MILNE POINT PRODUCTION FACILITY	AK	07/13/2001 ACT	HEATERS (2), H-5701A AND H-5701B	NAT GAS	29	MMBTU/H EACH	Sulfur Dioxide (SO2)	BURN NATURAL GAS WITH NO GREATER THAN 100 PPM H2S. BURN FUEL OIL WITH NO GREATER THAN 0 30 % SULFUR BY WEIGHT.	500	PPM	2 55	LB/MMBTU	CALCULATED, SEE NOTES	EMISSIONS IN LB/MMBTU WERE CALCULATED USING THE ASSUMPTION THAT EMISSIONS IN PPM ARE AT 15% O2 AND THE FUEL IS NATURAL GAS.
AK-0047	MILNE POINT PRODUCTION FACILITY	AK	07/13/2001 ACT	HEATERS (2), H-4510A AND H-4510B	NAT GAS	14.4	MMBTU/H EACH	Sulfur Dioxide (SO2)	USE FUEL OIL WITH NO GREATER THAN 0 3% SULFUR BY WEIGHT AND NATURAL GAS WITH NO GREATER THAN 100 PPMVD.	500	PPM	2 55	LB/MMBTU	CALCULATED, SEE NOTES	EMISSIONS IN LB/MMBTU WERE CALCULATED USING THE ASSUMPTION THAT EMISSIONS IN PPM ARE AT 15% O2 AND THE FUEL IS NATURAL GAS.
AK-0047	MILNE POINT PRODUCTION FACILITY	AK	07/13/2001 ACT	TURBINES (2), PU-0701 AND PU-0801	NATURAL GAS	29500	HP EACH	Sulfur Dioxide (SO2)	BURN NATURAL GAS WITH NO GREATER THAN 100 PPM H2S. BURN FUEL OIL WITH NO GREATER THAN 0 30 % SULFUR BY WEIGHT.	0 015	% SO2 @ 15% O2	0			NSPS LIMIT IS EITHER 0.015% SO2 @ 15% O2 IN EXHAUST OR 0.8% SULFUR BY WT IN ANY FUEL. ALSO SUBJECT TO SIP LIMIT OF 500 PPM (3 HR AVER).
AK-0047	MILNE POINT PRODUCTION FACILITY	AK	07/13/2001 ACT	HEATERS (2), H-5302A AND H-5302B	NATURAL GAS	35	MMBTU/H EA	Sulfur Dioxide (SO2)	BURN NATURAL GAS WITH NO GREATER THAN 100 PPM H2S. BURN FUEL OIL WITH NO GREATER THAN 0 30 % SULFUR BY WEIGHT.	500	PPM	2 55	LB/MMBTU	CALCULATED, SEE NOTES	EMISSIONS IN LB/MMBTU WERE CALCULATED USING THE ASSUMPTION THAT EMISSIONS IN PPM ARE AT 15% O2 AND THE FUEL IS NATURAL GAS.
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR TURBINE, CF-G-70002	FUEL GAS	11183	KW	Sulfur Dioxide (SO2)	BURN FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NO GREATER THAN 200 PPM OR DISTILLATE FUEL OIL WITH A FUEL SULFUR CONTENT NOT TO EXCEED 0.15%.	150	PPM	0			BACT-PSD IS CONSIDERED COMPLIANCE WITH NSPS BASIS OF DETERMINATION IN 40 CFR 60.333(A) AND (B). ADDITIONAL EMISSION LIMIT ACCORDING TO 18 AAC 50.055(C)- 500 PPM OVER 3 H AV.
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	CRUDE HEATER, CF-H-31003A	FUEL GAS	65.6	MMBTU/H	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%.	0		0		NOT AVAILABLE	18 AAC 50.055(C) LIMIT IS 500 PPM, 3 H AVER
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	CRUDE HEATER, CF-H-31003B	FUEL GAS	65.6	MMBTU/H	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%.	0		0		NOT AVAILABLE	18 AAC 50.055(C) LIMIT IS 500 PPM, 3 HR AVER
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	HEATER, DR14		3.5	MMBTU/H	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	MUD PLANT HEATER, DR15		4	MMBTU/H	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)

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AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	INJECTION TURBINE CF-C33012-TB	FUEL GAS	36700	HP	Sulfur Dioxide (SO2)	BURN FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NO GREATER THAN 200 PPM OR DISTILLATE FUEL OIL WITH A FUEL SULFUR CONTENT NOT TO EXCEED 0.15%.	150	PPM	0			
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR TURBINE, CF-G-70001	FUEL GAS	25800	KW	Sulfur Dioxide (SO2)	BURN FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NO GREATER THAN 200 PPM OR DISTILLATE FUEL OIL WITH A FUEL SULFUR CONTENT NOT TO EXCEED 0.15%.	150	PPM	0			BACT PSD IS CONSIDERED COMPLIANCE WITH NSPS BASIS OF DETERMINATION IN 40 CFR 60.333 (A) AND (B).
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	UTILITY HEATER MEDIUM, CF-H-64004	FUEL GAS	20	MMBTU/H	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	0		0			BACT-PSD IS CONSIDERED COMPLIANCE WITH NSPS STANDARD.
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	UTILITY HEATER MEDIUM, CF-H-64005	FUEL GAS	20	MMBTU/H	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	0		0			
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	COIL TUBING UNIT HEATERS		13	MMBTU/H	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATORS, 10-23		210	KW	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.20%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, 2		800	KW	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.20%.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	INCINERATOR, 3		750	LB/H	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.20%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, 4		160	KW	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.20%.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR DR1		700	KW	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	HP FLARE, CF-X-35002	FUEL GAS	261	MMSCF/D	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	0		0			
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	LP FLARE, CF-X-35012	FUEL GAS	212	MMSCF/D	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	0		0			
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, D1		379	KW	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)

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AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	RIG MOVE ENGINE NO. 1		376	HP	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR DR4		976	KW	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%.	500	PPM	0			BASIS OF DETERMINATION IS 18AAC 50.055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	COIL TUBING UNIT SMALL ENGINES		170	HP	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	EMERGENCY GENERATOR, CF-G-70003	FUEL OIL	2	MW	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%.	0		0			
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, DR5		700	KW	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055 (C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, DR6		700	KW	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, 1		930	KW	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.20%.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	LISTER BOILER, DR11		100	HP	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0		NOT AVAILABLE	BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	LISTER BOILER, DR12		100	HP	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A H2S CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A S CONTENT NOT TO EXCEED 0.15%	500	PPM	0		NOT AVAILABLE	BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	WASTE INCINERATOR, CF-U-590001B	WASTE	350	LB/H	Sulfur Dioxide (SO2)	REDUCED-SULFUR FUELS	0.42	LB/H	0			
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	WELL FRACTIONATION UNIT SMALL ENGINES		650	HP	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	WASTE INCINERATOR, CF-U-59001A	WASTE	350	LB/H	Sulfur Dioxide (SO2)	REDUCED-SULFUR FUEL	0.42	LB/H	0			

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AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	CEMENT PUMP, CP2		180	KW	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION: 18 AAC 50.055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR DR2		976	KW	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR DR3		700	KW	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, 25		30	KW	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.20%.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	ELECTRIC LINE UNIT ENGINE		600	HP CUMULATIVE	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	SICK LINE UNIT ENGINES		915	HP	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASED ON 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, 24		75	KW	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.20%.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, 5		160	KW	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.20%.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, 7		25	KW	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.20%.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	HEATER, DR13		4.2	MMBTU/H	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, 8		30	KW	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.20%.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, 9		120	KW	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.20%.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	COIL TUBING UNIT LARGE ENGINES		950	HP	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)

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AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, N2		376	HP	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.20%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, D2		379	KW	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.20%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(B)(1)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, N1		376	HP	Sulfur Dioxide (SO2)	USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.20%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	HEATER, MP1		1.3	MMBTU/H	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	EMERGENCY GENERATOR, CF-G-70004	FUEL OIL	2	MW	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%.	0		0			
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, BP1		300	KW	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%.	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	GENERATOR, BP2		160	KW	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	RIG MOVE ENGINE NO. 2		105	HP	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	RIG MOVE ENGINE NO. 3		105	HP	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION IS 18 AAC 50 055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	CEMENT PUMP, CP1		180	KW	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM AND USE DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS OF DETERMINATION IS: 18 AAC 50.055(C)
AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	WELL FRACTIONATION UNIT LARGE ENGINES		650	HP	Sulfur Dioxide (SO2)	USE ONLY FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NOT TO EXCEED 200 PPM, AND USE ONLY DISTILLATE FUEL OIL WITH A SULFUR CONTENT NOT TO EXCEED 0.15%	500	PPM	0			BASIS IS 18 AAC 50.055(C)

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AK-0053	KENAI REFINERY	AK	03/21/2000 ACT	WELL FRACTIONATION UNIT TURBINES		6200	HP	Sulfur Dioxide (SO2)	BURN FUEL GAS WITH A HYDROGEN SULFIDE CONTENT NO GREATER THAN 200 PPM OR DISTILLATE FUEL OIL WITH A FUEL SULFUR CONTENT NOT TO EXCEED 0.15%.	150	PPM	0			BASIS OF DETERMINATION IS 40CFR 60.333(A) AND (B). ADDITIONAL EMISSION LIMIT BASED ON 18 AAC 50 055(C)- 500 PPM OVER 3 H AV.
AK-0062	BADAMI DEVELOPMENT FACILITY	AK	08/19/2005 ACT	NATCO MISCIBLE INJECTION HEATER	NATURAL GAS	14 87	MMBTU/H	Sulfur Dioxide (SO2)	LIMIT SULFUR CONTENT OF FUEL COMBUSTED	250	PPMV	0			* LIMIT SULFUR CONTENT OF FUEL COMBUSTED
AK-0062	BADAMI DEVELOPMENT FACILITY	AK	08/19/2005 ACT	NATCO TEG REBOILER	NATURAL GAS	1 34	MMBTU/H	Sulfur Dioxide (SO2)	LIMIT SULFUR CONTENT OF FUEL COMBUSTED	250	PPMV	1 28	LB/MMBTU		LIMIT SULFUR CONTENT OF FUEL COMBUSTED
AK-0062	BADAMI DEVELOPMENT FACILITY	AK	08/19/2005 ACT	SOLAR MARS 90 TURBINE	NATURAL GAS	11 86	MW	Sulfur Dioxide (SO2)	LIMIT SULFUR CONTENT OF FUEL COMBUSTED	250	PPMV	0		*SEE NOTES	SEE NOTES; LIMIT SULFUR CONTENT OF FUEL COMBUSTED * S02 IS NOT REQUIRED FOR STANDARD UNITS OF PROCESS CODE 16.110
AK-0062	BADAMI DEVELOPMENT FACILITY	AK	08/19/2005 ACT	CUMMINS IC ENGINE GENERATOR	DIESEL FUEL	1855	HP	Sulfur Dioxide (SO2)	LIMIT SULFUR CONTENT OF FUEL COMBUSTED	0.15	% BY WT	0		* NOT AVAILABLE SEE NOTE	SEE NOTES: LIMIT SULFUR CONTENT OF FUEL COMBUSTED NOTE. FOR APPENDIX E PROCESS CODE 17,110 THE FOLLOWING POLUTANTS; (SO2, PM, AND VOC) - DO NOT REQUIRE STANDARD NUMERIC LIMITS OR EMISSION UNITS. * NOTE. FOR APPENDIX E PROCESS CODE 17,110 THE FOLLOWING POLUTANTS; (SO2, PM, AND VOC) - DO NOT REQUIRE STANDARD NUMERIC LIMITS OR EMISSION UNITS.
AK-0062	BADAMI DEVELOPMENT FACILITY	AK	08/19/2005 ACT	NATCO PRODUCTION HEATER	NATURAL GAS	34	MMBTU/H	Sulfur Dioxide (SO2)	LIMIT SULFUR CONTENT IN FUEL COMBUSTED	250	PPMV	0			LIMIT SULFUR CONTENT IN FUEL COMBUSTED * EMISSION UNITS AND NUMERIC LIMITS ARE REQUIRED FOR SO2 USING APPENDIX E. PROCESS CODE 13.110
AL-0168	GENPOWER KELLEY LLC	AL	01/12/2001 ACT	TURBINE, COMBINED CYCLE ELECTRIC GENERATING UNITS	NATURAL GAS	173	MW	Sulfur Dioxide (SO2)		0 002	LB/MMBTU	0			
AL-0168	GENPOWER KELLEY LLC	AL	01/12/2001 ACT	BOILER	NATURAL GAS	83	MMBTU/H	Sulfur Dioxide (SO2)		0 001	LB/MMBTU	0.001	LB/MMBTU		
AL-0169	BLOUNT MEGAWATT FACILITY	AL	02/05/2001 ACT	COMBUSTION TURBINES	NATURAL GAS	161	MW	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES	0 006	LB/MMBTU	0			
AL-0169	BLOUNT MEGAWATT FACILITY	AL	02/05/2001 ACT	AUXILIARY BOILER	NATURAL GAS	40	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES	0 006	LB/MMBTU	0.006	LB/MMBTU		
AL-0180	DUKE ENERGY DALE, LLC	AL	12/11/2001 ACT	2 GE 7FA GAS FIRED COMB. CYCLE W/568 MMBTU DUCT B	NATURAL GAS	170	MW EACH	Sulfur Dioxide (SO2)	NATURAL GAS AS EXCLUSIVE FUEL.	0.0057	LB/MMBTU	0			
AL-0180	DUKE ENERGY DALE, LLC	AL	12/11/2001 ACT	35 MMBTU/HR NAT. GAS FIRED AUXILIARY BOILER	NATURAL GAS	35	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS	0.0057	LB/MMBTU	0			
AL-0181	DUKE ENERGY AUTAUGA, LLC	AL	10/23/2001 ACT	31.4 MMBTU/HR NATURAL GAS FIRED BOILER	NATURAL GAS	31.4	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS IS EXCLUSIVE FUEL.	0.0057	LB/MMBTU	0			
AL-0190	GE PLASTICS	AL	07/13/2001 ACT	FURNACE, HOT OIL, 20 MMBTU/H	NATURAL GAS	20	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES	0.01	LB/H	0.0005	LB/MMBTU		
AL-0190	GE PLASTICS	AL	07/13/2001 ACT	FURNACE, HOT OIL, 10 MMBTU/H	NATURAL GAS	10	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES	0.01	LB/H	0.001	LB/MMBTU		
AL-0190	GE PLASTICS	AL	07/13/2001 ACT	PHOSGENE PRODUCTION UNIT, SCRUBBERS	NATURAL GAS	463	MMLB/YR	Sulfur Dioxide (SO2)	SCRUBBERS 1 & 2	1.12	LB/H	0			
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	Z-HIGH MILL WITH MIST ELIMINATOR (LO42) (MULTIPLE EMISSION POINTS)				Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LO43).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS -FIRED ANNEALING FURNACE (LA43) (MULTIPLE EMISSION POINTS)	NATURAL GAS	196.4	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LA43).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	2 ACID REGENERATION LINES EACH WITH CAUSTIC SCRUBBERS & COMMON SCR (LO72) (MULTIPLE EMISSION POINTS)	NATURAL GAS	20600	T/YR	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE 2 ACID REGENERATION LINES EACH WITH CAUSTIC SCRUBBER & COMMON SCR (LO72).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	DEGREASING WITH WET SCRUBBER (LO52) (MULTIPLE EMISSION POINTS)		60	T/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LO53).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	DEGREASING WITH WET SCRUBBER (MULTIPLE EMISSION POINTS)		60	T/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE.

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AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED BATCH ANNEALING FURNACES (LA63, LA64)	NATURAL GAS	33.4	MMBTU each	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED PASSIVE ANNEALING FURNACE (LO41)	NATURAL GAS	27.2	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	4 CONTINUOUS HOT DIP GALVANIZING LINE (EACH LINE WITH SAME MULTIPLE EMISSION POINTS)				Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 EMISSIONS FOR THE ANTI-CORROSIVE COATING WITH PRE & POST DRYERS.
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	4 CONTINUOUS HOT DIP GALVANIZING LINE (EACH LINE WITH SAME MULTIPLE EMISSION POINTS)				Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 EMISSIONS FOR THE ANNEALING FURNACES.
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	MELTSHOP - LO (MULTIPLE EMISSION POINTS)		126	T/H	Sulfur Dioxide (SO2)		0.15	LB/T	0			THIS COVERS SO2 EMISSIONS FOR THE AOD CONVERTER WITH ELEPHANT HOUSE & 2 LMFS VENTED TO COMMON BAGHOUSE (LO2).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	MELTSHOP - LO (MULTIPLE EMISSION POINTS)		126	T/H	Sulfur Dioxide (SO2)		0.15	LB/T	0			THIS COVERS SO2 FOR THE TPH EAF WITH DEC & ELEPHANT HOUSE VENTED TO BAGHOUSE (LO1).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	TPH ELECTRIC ARC FURNACE WITH DEC & ELEPHANT HOUSE VENTED TO BAGHOUSE 3 (LA1) (MULTIPLE EMISSION POINTS)	NATURAL GAS	126	T/H	Sulfur Dioxide (SO2)		0.15	LB/T	0			THIS COVERS SO2 FOR THE TPH ELECTRIC ARC FURNACE WITH DEC & ELEPHANT HOUSE VENTED TO BAGHOUSE 3 (LA1).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	TPH ELECTRIC ARC FURNACE WITH DEC & ELEPHANT HOUSE VENTED TO BAGHOUSE 3 (LA1) (MULTIPLE EMISSION POINTS)	NATURAL GAS	126	T/H	Sulfur Dioxide (SO2)		0.15	LB/T	0			THIS COVERS SO2 FOR THE ARGON-OXYGEN DECARBURIZATION FURNACE WITH ELEPHANT HOUSE & 2 LADLE METALLURGY STATIONS VENTED TO COMMON BAGHOUSE.
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	169	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED REHEAT FURNACE (LA 21).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	169	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE 3 COIL DRUM FURNACES (LA24-LA26).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED REHEAT FURNACE (LA21) (MULTIPLE EMISSION POINTS)	NATURAL GAS	169	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE PLATE ANNEALING FURNACE (LA27).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	BAL STEAM SWEEP WITH MIST ELIMINATOR (LA66) (MULTIPLE EMISSION POINTS)		12.6	T/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 FOR THE NATURAL GAS-FIRED ANNEALING FURNACE (LA70).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	3 NATURAL GAS-FIRED BOILERS WITH ULNB & EGR (537-539)	NATURAL GAS	64.9	MMBTU each	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	HOT STRIP MILL (MULTIPLE EMISSION POINTS)	NATURAL GAS	690	T/H	Sulfur Dioxide (SO2)		0 006	LB/MMBTU	0			THIS COVERS SO2 EMISSIONS FROM THE 4 NATURAL GAS-FIRED WALKING BEAM REHEAT FURNACES.
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	HCL ACID REGENERATION (MULTIPLE EMISSION POINTS)	NATURAL GAS	3.77	T/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			THIS COVERS SO2 EMISSIONS FOR THE 2 REGENERATION TRAINS WITH CAUSTIC SCRUBBER (5-10).
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	AL	08/17/2007 ACT	NATURAL GAS-FIRED BATCH ANNEALING FURNACE (535)	NATURAL GAS	99	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AL-0231	NUCOR DECATUR LLC	AL	06/12/2007 ACT	TWO (2) ELECTRIC ARC FURNACES AND THREE (3) LADLE METALLURGY FURNACES WITH TWO (2) MELTSHOP BAGHOUSES	ELECTRICITY	440	T/H	Sulfur Dioxide (SO2)		0.62	LB/T	0			
AL-0231	NUCOR DECATUR LLC	AL	06/12/2007 ACT	VACUUM DEGASSER BOILER	NATURAL GAS	95	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AL-0231	NUCOR DECATUR LLC	AL	06/12/2007 ACT	GALVANIZING LINE FURNACE	NATURAL GAS	98.7	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AL-0231	NUCOR DECATUR LLC	AL	06/12/2007 ACT	VACUUM DEGASSER		440	T/H	Sulfur Dioxide (SO2)		0 005	LB/T	0			
AR-0040	DUKE ENERGY HOT SPRINGS	AR	12/29/2000 ACT	BOILERS, AUXILIARY 2	NATURAL GAS	44.1	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	2	GR/DSCF	0.006	LB/MMBTU		
AR-0040	DUKE ENERGY HOT SPRINGS	AR	12/29/2000 ACT	TURBINE, DUCT BURNER, (4), GE 7FA CT/HRSG	NATURAL GAS	580	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS. FUEL SULFUR CONTENT IS 0 05% BY WEIGHT	0 006	LB/MMBTU	0.006	LB/MMBTU		
AR-0051	DUKE ENERGY-JACKSON FACILITY	AR	04/01/2002 ACT	TURBINES, COMBINED CYCLE, NATURAL GAS, (2)	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)	CLEAN FUEL	0		0			fuel limit: < 2 gr S/100 dscf
AR-0051	DUKE ENERGY-JACKSON FACILITY	AR	04/01/2002 ACT	BOILER, AUXILIARY	NATURAL GAS	33	MMBTU/H	Sulfur Dioxide (SO2)	FUELS LIMIT: < 2 GR/100 DSCF	0		0			no emission rate limit, fuels limit.
AR-0051	DUKE ENERGY-JACKSON FACILITY	AR	04/01/2002 ACT	GENERATOR, DIESEL-FIRED	DIESEL FUEL	671	HP	Sulfur Dioxide (SO2)	FUELS LIMIT: 0 05% S BY WT	0		0			no emission rate limit, limit is fuels limit.

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	BRINE REDUCTION AREA SN-PBCDF-07	NATURAL GAS	0 01	MMDSCF/H	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS ONLY.	0.1	LB/H	0.008	LB/MMBTU	CALCULATED	
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	BOILER, HOT WATER, (2) SN-PBCDF-05, -06	NATURAL GAS	0 01	MMDSCF/H	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS ONLY.	0.1	LB/H	0.0085	LB/MMBTU	CALCULATED	
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	INCINERATOR COMMON STACK SN-PBCDF-01	NAT GAS, CHEM AGENT	40	ROCKETS/H	Sulfur Dioxide (SO2)	QUENCH TOWER WITH CAUSTIC SCRUBBING LIQUID FOLLOWED BY VENTURI SCRUBBER (COMBINED EFFICIENCY 50%), FOLLOWED BY A PACKED-BED SCRUBBER (95% EFFICIENCY). OVERALL SYSTEM IS EXPECTED TO REMOVE 97.5% OF SO2.	17.2	LB/H	0			THE MOST STRINGENT CONTROL WAS SELECTED: A PACKED BED SCRUBBER, IN CONJUNCTION WITH A QUENCH TOWER AND VENTURI SCRUBBER.
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	BOILER, PROCESS STEAM, (2) SN-PBCDF-03, -04	NATURAL GAS	0 03	MMDSCF/H	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS ONLY.	0.1	LB/H	0.0035	LB/MMBTU	CALCULATED	
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	BOILER, LABORATORY SN-PBCDF-16	NATURAL GAS	1.4	mmbtu/h	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS ONLY.	0.1	LB/H	0.071	LB/MMBTU	CALCULATED	
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	IC ENGINE, EMERGENCY GENERATOR (2)	DIESEL FUEL	2500	KW	Sulfur Dioxide (SO2)	LOW SULFUR DIESEL: LESS THAN OR EQUAL TO 0.05 WT % S. ALSO: LIMITATION OF OPERATING HOURS TO LESS THAN 1200 COMBINED HOURS/YR FOR SN-PBCDF-09 AND SN-PBCDF-10 AND LESS THAN 500 HOURS/YR FOR SN-PBCDF-12.	0.6	LB/H	0			
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	IC ENGINE, EMERGENCY GENERATOR SN-PBCDF-12	DIESEL FUEL	250	KW	Sulfur Dioxide (SO2)	LOW SULFUR DIESEL; <= 0.05 WT % S. ALSO OPERATING LIMIT: < 500 H/YR.	0.4	LB/H	0			
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	GALVANIZING LINE	NATURAL GAS	9	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY	0.0006	LB/MMBTU	0			
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	BOILERS	NATURAL GAS	22	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	DEGASSER HOTWELL FLARE	NATURAL GAS			Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY IN FLARE	0.09	LB/H	0			
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	TUNNEL FURNACE	NATURAL GAS	160	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY	0.0006	LB/MMBTU	0.0006	LB/MMBTU		ADDITIONAL LIMIT: .1 LB/H
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	ELECTRIC ARC FURNACE (EAF)	NATURAL GAS	350	t/h	Sulfur Dioxide (SO2)	LOW SULFUR COKE AND SCRAP MANAGEMENT	0.2	LB/T	0			
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	LADLE METALLURGY FURNACE		350	T/H	Sulfur Dioxide (SO2)		0.08	LB/T	0			
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	FURNACES, HEATERS, & DRYERS	NATURAL GAS	11	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
AR-0086	NUCOR-YAMATO STEEL COMPANY, BLYTHEVILLE MILL	AR	06/11/2004 ACT	EAF #1 BAGHOUSE, SN-01	NATURAL GAS	450	T/H STEEL	Sulfur Dioxide (SO2)	LOW SULFUR COKE USAGE	90	LB/H	0.2	LB/T STEEL		
AR-0086	NUCOR-YAMATO STEEL COMPANY, BLYTHEVILLE MILL	AR	06/11/2004 ACT	LMF #1 BAGHOUSE, SN-35		250	T/YR STEEL	Sulfur Dioxide (SO2)	LOW SULFUR COKE USAGE	90	LB/H	0 36	LB/T STEEL		
AR-0086	NUCOR-YAMATO STEEL COMPANY, BLYTHEVILLE MILL	AR	06/11/2004 ACT	VTD BOILER	NATURAL GAS	50	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE, NATURAL GAS COMBUSTION	0.1	LB/H	0.0006	LB/MMBTU		
AR-0090	NUCOR STEEL, ARKANSAS	AR	04/03/2006 ACT	LADLE DRYER	NATURAL GAS			Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AR-0090	NUCOR STEEL, ARKANSAS	AR	04/03/2006 ACT	EAF'S LMF'S	NATURAL GAS	585	TONS STEEL	Sulfur Dioxide (SO2)		176.8	LB/H	0.2	LB/T STEEL		
AR-0090	NUCOR STEEL, ARKANSAS	AR	04/03/2006 ACT	PICKLE LINE BOILERS, SN-52	NATURAL GAS	12.6	MMBTU EACH	Sulfur Dioxide (SO2)		0.1	LB/H	0.0006	LB/MMBTU		
AR-0090	NUCOR STEEL, ARKANSAS	AR	04/03/2006 ACT	ANNEALING FURNACES SN-61	NATURAL GAS	4.8	LB/MMBTU	Sulfur Dioxide (SO2)		0.1	LB/H	0.0006	LB/MMBTU		
AR-0090	NUCOR STEEL, ARKANSAS	AR	04/03/2006 ACT	GALVANIZING LINE, SN-54	NATURAL GAS			Sulfur Dioxide (SO2)		0.1	LB/H	0.0006	LB/MMBTU		
AR-0090	NUCOR STEEL, ARKANSAS	AR	04/03/2006 ACT	MISCELLANEOUS NATURAL GAS FIRED BURNERS AND DRYERS				Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
AZ-0047	WELLTON MOHAWK GENERATING STATION	AZ	12/01/2004 ACT	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - SW501F TURBINES OPTION	NATURAL GAS	180	MW	Sulfur Dioxide (SO2)		0.0023	LB/MMBTU	0			
AZ-0047	WELLTON MOHAWK GENERATING STATION	AZ	12/01/2004 ACT	AUXILIARY BOILER	NATURAL GAS	38	MMBTU/H	Sulfur Dioxide (SO2)		0.0023	LB/MMBTU	0.0023	LB/MMBTU		
AZ-0047	WELLTON MOHAWK GENERATING STATION	AZ	12/01/2004 ACT	COMBUSTION TURBINE GENERATORS AND HEAT RECOVERY STEAM GENERATORS - GE7FA TURBINES OPTION	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)		0.0023	LB/MMBTU	0			

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AZ-0049	LA PAZ GENERATING FACILITY	AZ	09/04/2003 ACT	SIEMENS WESTINGHOUSE COMBUSTION TURBINES AND HEAT RECOVERY STEAM GENERATORS	NATURAL GAS	1080	MW	Sulfur Dioxide (SO2)		0.0021	LB/MMBTU	0			
AZ-0049	LA PAZ GENERATING FACILITY	AZ	09/04/2003 ACT	GE COMBUSTION TURBINES AND HEAT RECOVERY STEAM GENERATORS	NATURAL GAS	1040	MW	Sulfur Dioxide (SO2)		0.0021	LB/MMBTU	0			
AZ-0049	LA PAZ GENERATING FACILITY	AZ	09/04/2003 ACT	AUXILIARY BOILER FOR GE TURBINE	NATURAL GAS	41	MMBTU/H	Sulfur Dioxide (SO2)		0.0025	LB/MMBTU	0.0025	LB/MMBTU		
AZ-0049	LA PAZ GENERATING FACILITY	AZ	09/04/2003 ACT	AUXILIARY BOILER FOR SIEMENS TURBINES	NATURAL GAS	55 34	MMBTU/H	Sulfur Dioxide (SO2)		0.0025	LB/MMBTU	0.0025	LB/MMBTU		
FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	01/10/2007 ACT	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	NATURAL GAS	2333	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	2	GS/100 SCF GAS	0			SULFUR FUEL SPECIFICATIONS COMBINED WITH THE EFFICIENT COMBUSTION DESIGN AND OPERATION OF EACH GAS TURBINE REPRESENTS (BACT) FOR PM/PM10 EMISSIONS.
FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	01/10/2007 ACT	TWO 99.8 MMBTU/H GAS-FUELED AUXILIARY BOILERS	NATURAL GAS	99.8	MMBTU/H	Sulfur Dioxide (SO2)		2	GS/100 SCF GAS	0			
FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	01/10/2007 ACT	TWO GAS-FUELED 10 MMBTU/H PROCESS HEATERS	NATURAL GAS	10	MMBTU/H	Sulfur Dioxide (SO2)		2	GS/100 SCF GAS	0			
FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	01/10/2007 ACT	FOUR 2250 KW LIQUID FUEL EMERGENCY GENERATORS	FUEL OIL			Sulfur Dioxide (SO2)		0.0015	% S FUEL OIL	0			
FL-0335	SUWANNEE MILL	FL	09/05/2012 ACT	Four(4) Natural Gas Boilers - 46 MMBtu/hour	Natural Gas	46	MMBTU/H	Sulfur Dioxide (SO2)	Good Combustion Practice	2	GR OF S/100 SCF	0			Basis for standard is Reasonable Assurance. ?FM? means fuel monitoring to demonstrate that the sulfur content of the natural gas is 2 grains per hundred standard cubic foot (gr/100 scf) or less. Vendor certification can be used in lieu of FM
FL-0335	SUWANNEE MILL	FL	09/05/2012 ACT	Two(2) Biomass-Fuel Boilers - 120 MMBtu/hr each	wood products	120	MMBTU/H	Sulfur Dioxide (SO2)	Sulfur dioxide (SO2) will be minimized by the use of low sulfur fuels.	0.0336	LB/MMBTU	0			The SO2 limit in terms of ?lb/MMBtu? will ensure that the biomass boilers meet the SO2 emission limit exemption in §60.42b(k)(2) of NSPS Subpart Db. A ?state? BACT is required for SO2 in accordance with Rule 62-296.406(3), F A.C for Fossil Fuel Steam Generators with Less than 250 MMBtu/hr Heat Input. This requirement is met by firing only low sulfur biomass fuels in the boilers.
IA-0062	EMERY GENERATING STATION	IA	12/20/2002 ACT	IC ENGINE, EMERGENCY FIRE PUMP	#2 FUEL OIL	2 59	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.51	LB/MMBTU	0			
IA-0062	EMERY GENERATING STATION	IA	12/20/2002 ACT	IC ENGINE, BLACK-START GENERATOR (6)	#2 FUEL OIL	25	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL.	0.51	LB/MMBTU	0			
IA-0062	EMERY GENERATING STATION	IA	12/20/2002 ACT	TURBINE, SIMPLE CYCLE, (2)	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)	LOW SULFUR NG. < 0.8 GR/100 SCF OR < 0 05% S BY WT FUEL OIL.	0.0022	LB/MMBTU	0			
IA-0062	EMERY GENERATING STATION	IA	12/20/2002 ACT	TURBINE, COMBINED CYCLE (2)	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, NG. NATURAL GAS < 0 8 GR/100SCF; FUEL OIL < 0.05% S BY WT	0.0022	LB/MMBTU	0			
IA-0062	EMERY GENERATING STATION	IA	12/20/2002 ACT	GAS HEATER, (2)	NATURAL GAS	16.4	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, NG	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
IA-0062	EMERY GENERATING STATION	IA	12/20/2002 ACT	AUXILIARY BOILER	NATURAL GAS	68	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, NG	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
IA-0068	EMERY GENERATING STATION	IA	06/26/2003 ACT	GAS HEATER	NATURAL GAS	9	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, NATURAL GAS	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	DDGS COOLER		140	T/H OF DRY FEED	Sulfur Dioxide (SO2)		10	PPMVD	0			SO2 OCCURS FROM THE USE OF WET MILL PROCESS WATER THAT IS LADEN WITH SO2.
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	INDIRECT-FIRED DDGS DRYER	NATURAL GAS	93.7	MMBTU/H	Sulfur Dioxide (SO2)		6	PPMVD	0			
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	GERM DRYERS AND COOLERS		15	T/H	Sulfur Dioxide (SO2)	WET SCRUBBER	10	PPMVD	0			SO2 OCCURS FROM THE USE OF WET MILL PROCESS WATER THAT IS LADEN WITH SO2.
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	FIRE PUMP	DIESEL #2	540	HP	Sulfur Dioxide (SO2)	BURN LOW-SULFUR DIESEL FUEL. 0.05% BY WEIGHT OR LESS NOT TO EXCEED THE NSPS REQUIREMENT.	0.17	G/B-HP-H	0			
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	WASTEWATER TREATMENT PLANT (WWTP) ANAEROBIC DIGESTER		1500	SCFM OF BIOGAS	Sulfur Dioxide (SO2)	LIMITED THE HYDROGEN SULFIDE CONCENTRATION OF THE BOIGAS PRODUCED TO 200 PPMV (24-HOUR ROLLING AVERAGE).	0 023	LB/MMBTU	0			
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	FERMENTATION, DISTILLATION AND DEHYDRATION		840000	GAL/H	Sulfur Dioxide (SO2)	CO2 SCRUBBER AND DISTILLATION NCG SCRUBBER	90	% REDUCTION	0			SO2 OCCURS FROM THE USE OF WET MILL PROCESS WATER THAT IS LADEN WITH SO2. THE CO2 SCRUBBER CONTROLS THE FERMENTATION TANKS, YEAST PROPAGATORS AND BEERWELLS. THE NCG SCRUBBER CONTROLS THE NITROGEN STRIPPER AND DISTILLATION COLUMN. THE PERCENT REDUCTION LIMIT APPLIES ACROSS BOTH OF THE SCRUBBER INDIVIDUALLY. THE CONCENTRATION LIMIT APPLIES TO THE OUTLET OF THE RTO, WHICH IS AFTER THE SCRUBBERS. THE LIMITS ARE WRITTEN AS 90 % REDUCTION OR 10 PPMV.

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IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	NATURAL GAS BOILER (292.5 MMBTU/H)	NATURAL GAS	292.5	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL ONLY	0.0006	LB/MMBTU	0			
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	EMERGENCY GENERATOR	DIESEL	1500	KW	Sulfur Dioxide (SO2)	BURN LOW-SULFUR DIESEL FUEL. 0.05% BY WEIGHT OR LESS NOT TO EXCEED THE NSPS REQUIREMENT.	0.17	G/B-HP-H	0			
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	IA	06/29/2007 ACT	ALCOHOL RAIL LOADOUT		12000	GAL/MIN	Sulfur Dioxide (SO2)	FUEL FIRED IN THE FLARE IS LIMITED TO NATURAL GAS AND BIOGAS	0.0025	LB/MMBTU	0			TON PER YEAR LIMIT IS THE SUM OF EMISSIONS FROM BOTH ALCOHOL LOADOUT FLARES AND CORRESPONDS TO A PLANTWIDE LOADOUT LIMIT OF 752,325,000 GALLONS OF ETHANOL PER 12-MONTH ROLLING PERIOD.
IN-0086	MIRANT SUGAR CREEK, LLC	IN	05/09/2001 ACT	AUXILARY BOILER, NATURAL GAS (2)	NATURAL GAS	35	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR NATURAL GAS ONLY (LESS THAN 0 8% BY WEIGHT). LB/H LIMIT IS FOR EACH BOILER.	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
IN-0086	MIRANT SUGAR CREEK, LLC	IN	05/09/2001 ACT	TURBINE, NATURAL GAS, SIMPLE CYCLE, FOUR	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)	GOOD COMBUSTION. LOW SULFUR NATURAL GAS (LESS THAN 0.8% BY WEIGHT). LB/H LIMIT IS FOR EACH CT.	0.0028	LB/MMBTU	0			
IN-0086	MIRANT SUGAR CREEK, LLC	IN	05/09/2001 ACT	TURBINE, NATURAL GAS, COMBINED CYCLE	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)	LOW SULFUR NATURAL GAS ONLY (LESS THAN 0 8% BY WEIGHT). EMISSION LIMIT IS FOR EACH CT.	4.2	LB/H	0			
IN-0087	DUKE ENERGY, VIGO LLC	IN	06/06/2001 ACT	TURBINE, NATURAL GAS, COMBINED CYCLE (2)	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)	GOOD COMBUSTION. NATURAL GAS ONLY. UNFIRED EMISSIONS = 11.35 LB/H. LB/H LIMIT IS FOR EACH CT.	0.0057	LB/MMBTU	0			
IN-0087	DUKE ENERGY, VIGO LLC	IN	06/06/2001 ACT	AUXILARY BOILER, NATURAL GAS (2)	NATURAL GAS	46	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS AS FUEL. LIMIT IS FOR EACH BOILER.	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
IN-0090	NUCOR STEEL	IN	01/19/2001 ACT	BATCH ANNEALING FURNACE, 18	NATURAL GAS	4.8	MMBTU/H EACH	Sulfur Dioxide (SO2)	PERMIT LIMITATION IS USAGE OF NATURAL GAS OR PROPANE ONLY	0		0			
IN-0090	NUCOR STEEL	IN	01/19/2001 ACT	TUNDISH PREHEATERS (2)		6	MMBTU/H	Sulfur Oxides (SOx)	PERMIT LIMITATION IS USE OF NATURAL GAS.	0		0			
IN-0090	NUCOR STEEL	IN	01/19/2001 ACT	STRIP CASTER LINE		135	T/H	Sulfur Dioxide (SO2)		0.185	LB/T	0			
IN-0090	NUCOR STEEL	IN	01/19/2001 ACT	LADLE PREHEATERS	NATURAL GAS	15	MMBTU/HR EACH	Sulfur Dioxide (SO2)	PERMIT LIMITATION IS NATURAL GAS OR PROPANE USAGE	0		0			
IN-0095	ALLEGHENY ENERGY SUPPLY CO. LLC	IN	12/07/2001 ACT	AUXILLIARY BOILER	NATURAL GAS	21	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR CONTENT NATURAL GAS	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
IN-0095	ALLEGHENY ENERGY SUPPLY CO. LLC	IN	12/07/2001 ACT	TWO SIMPLE CYCLE COMBUSTION TURBINES GELM6000	NATURAL GAS	469	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR NATURAL GAS	0.0035	LB/MMBTU	0.7	PPM@ 15% O2 (EST.)		
IN-0095	ALLEGHENY ENERGY SUPPLY CO. LLC	IN	12/07/2001 ACT	2 CMBND CYCLE COMBUST. TURBINE WESTINGHOUSE 501F	NATURAL GAS	2071	MMBTU/H (HHV)	Sulfur Dioxide (SO2)	USE OF LOW SULFUR NATURAL GAS AS SOLE FUEL	0.0034	LB/MMBTU	0.7	PPM @15% O2 (EST.)		
IN-0108	NUCOR STEEL	IN	11/21/2003 ACT	EAF, AOD VESSELS, DESULFURIZATION, & OTHER PROCESS	NATURAL GAS	502	T/H	Sulfur Dioxide (SO2)	SCRAP MANAGEMENT PLAN. COMPLIANCE METHOD: SO2 CEM.	0.25	LB/T	0			These SO2 limits cover emissions from the EAFs, AOD, desulfurization and continuous casters in the meltshop area. The limits supersede limits in PSD permit 107-2764, issued 11/30/93 and PSD permit 107-5235, issued on 6/30/96
IN-0108	NUCOR STEEL	IN	11/21/2003 ACT	LADLE METALLURGY FURNACES (2)		502	T/H	Sulfur Dioxide (SO2)		0.185	LB/T	0			Compliance testing. Sulfur content of the charge carbon and injection carbon added to the LMFs is monitored.
IN-0108	NUCOR STEEL	IN	11/21/2003 ACT	BOILER, NATURAL GAS, (2)	NATURAL GAS	34	MMBTU/H	Sulfur Dioxide (SO2)	COMPLIANCE BY USING NATURAL GAS	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
IN-0110	COGENTRIX LAWRENCE CO., LLC	IN	10/05/2001 ACT	TURBINES, COMBINED CYCLE, (3)	NATURAL GAS	1944.1	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE	0 006	LB/MMBTU	0			
IN-0110	COGENTRIX LAWRENCE CO., LLC	IN	10/05/2001 ACT	TURBINES, COMBINED CYCLE, & DUCT BURNERS, (3)	NATURAL GAS	1944.1	MMBTU/H	Sulfur Oxides (SOx)	GOOD COMBUSTION PRACTICE	0 006	LB/MMBTU	0			
IN-0110	COGENTRIX LAWRENCE CO., LLC	IN	10/05/2001 ACT	BOILER, AUXILIARY, NATURAL GAS	NATURAL GAS	35	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE	0 006	LB/MMBTU	0.006	LB/MMBTU		
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/03/2012 ACT	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION TURBINES	NATURAL GAS	2300	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SPECIFICATION	0.75	GR S/100 SCF FUEL	0			
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/03/2012 ACT	TWO (2) NATURAL GAS AUXILIARY BOILERS	NATURAL GAS	80	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SPECIFICATIONS	0.0022	LB/MMBTU	0			LIMIT ONE AND TWO ARE FOR EACH BOILER
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/03/2012 ACT	TWO (2) FIREWATER PUMP DIESEL ENGINES	DIESEL	371	BHP, EACH	Sulfur Dioxide (SO2)	ULTRA LOW SULFUR DISTILLATE AND USAGE LIMITS	0.0015	% SUFLUR DIESEL FUEL	0			LIMIT ONE AND TWO ARE FOR EACH FIREWATER PUMP ENGINE. LIMIT THREE: EACH FIRE PUMP SHALL NOT EXCEED 500 HOURS OF OPERATION PER YEAR.
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/03/2012 ACT	TWO (2) EMERGENCY DIESEL GENERATORS	DIESEL	1006	HP EACH	Sulfur Dioxide (SO2)	ULTRA LOW SULFUR DISTILLATE AND USAGE LIMITS	0 012	LB/H	0			LIMIT ONE AND TWO ARE FOR EACH GENERATOR
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	IN	12/03/2012 ACT	EMERGENCY DIESEL GENERATOR	DIESEL	2012	HP	Sulfur Dioxide (SO2)	ULTRA LOW SULFUR DISTILLATE AND UASGE LIMITS	0 024	LB/H	0			LIMIT ONE AND TWO ARE FOR EACH GENERATOR

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
KY-0087	QUEBECOR WORLD FRANKLIN	KY	07/12/2002 ACT	BOILER, NATURAL GAS, #4	NATURAL GAS	33.5	MMBTU/H	Sulfur Dioxide (SO2)	CLEAN FUEL: FUEL OIL LIMITED TO < 0.5% S BY WT	1 057	LB/MMBTU	1.057	LB/MMBTU		
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	BLEACH PLANT NO. 2		668	T/D	Sulfur, Total Reduced (TRS)		0.12	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	TOWEL MACHINE NO. 6 TAD EXHAUST 2	NATURAL GAS	306	T/D	Sulfur Dioxide (SO2)	NATURAL GAS AS FUEL	0.04	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	TOWEL MACHINE NO. 6 YANKEE AIRCAP EXHAUST		306	T/D	Sulfur Dioxide (SO2)	NATURAL GAS AS FUEL	0.02	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 1		2 81	MM LB/D	Sulfur Dioxide (SO2)		105.91	LB/H	0			ADDITIONAL EMISSION LIMIT: 120 PPMV @ 8% O2.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 1		2 81	MM LB/D	Sulfur, Total Reduced (TRS)	UPGRADE BLOX SYSTEM	4.53	LB/H	0			ADDITIONAL EMISSION LIMIT: 5 PPMV AT 8% O2
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	TOWEL MACHINE NO. 6 TAD EXHAUST 1	NATURAL GAS	306	T/D	Sulfur Dioxide (SO2)	NATURAL GAS AS FUEL	0.07	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 2		3 96	MM LB/D	Sulfur Dioxide (SO2)		143.23	LB/H	0			ADDITIONAL EMISSION LIMIT: 120 PPMV AT 8% O2.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	RECOVERY FURNACE NO. 2		3 96	MM LB/D	Sulfur, Total Reduced (TRS)	UPGRADE BLOX SYSTEM	6.13	LB/H	0			ADDITIONAL EMISSION LIMIT: 5 PPMV AT 8% O2
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	BLEACH PLANT NO. 1		1024	T/D	Sulfur, Total Reduced (TRS)		0.19	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	SMELT TANK NO. 1		3 32	MM LB BLS/D	Sulfur, Total Reduced (TRS)		0.84	LB/H	0.032	LB/T BLS	CALCULATED	ADDITIONAL EMISSION LIMIT USED TO CALCULATE STANDARDIZED EMISSIONS: 0.016 G/KG BLS FIRED.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	SMELT TANK NO. 1		3 32	MM LB BLS/D	Sulfur Dioxide (SO2)	WET SCRUBBER	9.22	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	SMELT TANK NO. 2		2 25	MM LB BLS/D	Sulfur Dioxide (SO2)	WET SCRUBBERS	6.24	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	SMELT TANK NO. 2		2 25	MM LB BLS/D	Sulfur, Total Reduced (TRS)	WET SCRUBBER	0.63	LB/H	0.032	LB/T BLS	CALCULATED	ADDITIONAL EMISSION LIMIT USED TO CALCULATE STANDARDIZED EMISSIONS: 0.016 G/KG BLS FIRED.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	LIME KILN NO. 1		340	T/D	Sulfur Dioxide (SO2)	WET SCRUBBERS AND OPTIMAL MUD WASHING	3.26	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	LIME KILN NO. 1		340	T/D	Sulfur, Total Reduced (TRS)		3.5	LB/H	8	PPMV @ 10% O2		
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	LIME KILN NO. 2		270	T/D	Sulfur Dioxide (SO2)	WET SCRUBBERS AND OPTIMAL MUD WASHING	2.59	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	LIME KILN NO. 2		270	T/D	Sulfur, Total Reduced (TRS)		2.81	LB/H	8	PPMV @ 10% O2		
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	POWER BOILER NO. 5	NATURAL GAS	987	MMBTU/H	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS	5126	LB/H	5.19	LB/MMBTU		
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	POWER BOILER NO. 5	NATURAL GAS	987	MMBTU/H	Sulfur, Total Reduced (TRS)		0.48	LB/H	0			
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	BLEACH PLANT NO. 3		623	T/D	Sulfur, Total Reduced (TRS)		0.11	LB/H	0			.
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	POWER BOILER NO. 2	NAT GAS	65.5	MMBTU/H	Sulfur Dioxide (SO2)	FIRING NATURAL GAS	0.26	LB/H	0.004	LB/MMBTU		
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	COMBINATION BOILER NO. 1	WOOD WASTE / NAT GAS	459.5	MMBTU/H	Sulfur Dioxide (SO2)	ADD-ON: WET SCRUBBER. P2: FUEL CAN BE EITHER WOOD WASTE OR NATURAL GAS.	37.37	LB/H	0.73	LB/MMBTU		
LA-0174	PORT HUDSON OPERATIONS	LA	01/25/2002 ACT	COMBINATION BOILER NO. 1	WOOD WASTE / NAT GAS	459.5	MMBTU/H	Sulfur, Total Reduced (TRS)		0.46	LB/H	0			
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	GAS TURBINES - 187 MW (2)		2006	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR NATURAL GAS, 1.8 GRAINS PER 100 SCF	10.1	LB/H	0			
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	FUEL GAS HEATERS (3)		19	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR PIPELINE NATURAL GAS AND GOOD COMBUSTION PRACTICES	0 008	LB/H	0.0004	LB/MMBTU	ANNUAL AVERAGE	*TPY LIMIT FOR ALL 3 HEATERS. AGGREGATE HEAT INPUT IS LIMITED TO 14,250 MM BTU/YR. ONLY 2 OF THE 3 HEATERS ARE ALLOWED TO OPERATE AT ANY GIVEN TIME.
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	DIESEL FIRED WATER PUMP				Sulfur Dioxide (SO2)	GOOD ENGINE DESIGN AND PROPER OPERATING PRACTICES	0.61	LB/H	0.65	G/B-HP-H	ANNUAL AVERAGE	OPERATING TIME = 52 HR/YR
LA-0192	CRESCENT CITY POWER	LA	06/06/2005 ACT	DUCT BURNERS (2)		759	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR NATURAL GAS, 1.8 GRAINS PER 100 SCF	3.8	LB/H	0.005	LB/MMBTU	ANNUAL AVERAGE	
LA-0203	OAKDALE OSB PLANT	LA	06/13/2005 ACT	ROTARY DRYER NOS. 1-3	WOOD	300000	MSF/YR 3/8 inch basi	Sulfur Dioxide (SO2)		4.18	LB/H	0			
LA-0203	OAKDALE OSB PLANT	LA	06/13/2005 ACT	AUXILIARY THERMAL OIL HEATER	NATURAL GAS	66.5	MMBTU/H	Sulfur Dioxide (SO2)	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES	0.05	LB/H	0.001	LB/MMBTU	CALCULATED BY CATC	
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	SHIFT REACTOR STARTUP HEATER	NATURAL GAS	34.2	MMBTU/H	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR SUBSTITUTE NATURAL GAS (SNG)	0.02	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	GASIFIER STARTUP PREHEATER BURNERS (5)	NATURAL GAS	35	MMBTU/H	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR SUBSTITUTE NATURAL GAS (SNG)	0.02	LB/H	0			

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LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	ACID GAS FLARE	NATURAL GAS	0 27	MMBTU/H	Sulfur Dioxide (SO2)	NO ADDITIONAL CONTROL	0.01	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	FIRE WATER DIESEL PUMPS (3)	DIESEL	575	HP EACH	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART IIII	0.01	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	HYDROCARBON/GASIFIERS STARTUP FLARE	NATURAL GAS	487 55	MMBTU/H	Sulfur Dioxide (SO2)	NO ADDITIONAL CONTROL	1303.99	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	METHANATION STARTUP HEATERS	NATURAL GAS	56.9	MMBTU/H	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR SUBSTITUTE NATURAL GAS (SNG)	0.03	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	AUXILIARY BOILER	NATURAL GAS	938.3	MMBTU/H	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR SUBSTITUTE NATURAL GAS (SNG)	0.28	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	THERMAL OXIDIZERS (2)	NATURAL GAS	40.9	MMBTU/H	Sulfur Dioxide (SO2)	NO ADDITIONAL CONTROL	22.92	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	EMERGENCY DIESEL POWER GENERATOR ENGINES (2)	DIESEL	1341	HP EACH	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60 SUBPART IIII	0.01	LB/H	0			
LA-0231	LAKE CHARLES GASIFICATION FACILITY	LA	06/22/2009 ACT	WET SULFURIC ACID PLANTS (2)		2000	T/D	Sulfur Dioxide (SO2)	HYDROGEN PEROXIDE SCRUBBERS	13.8	LB/H	0			
LA-0246	ST. CHARLES REFINERY	LA	12/31/2010 ACT	EQT0323 - Boiler 401F	refinery fuel	99	MMBTU/H	Sulfur Dioxide (SO2)	Natural gas or Refinery Fuel Gas with H2S <=100 ppv (annual average)	2.54	LB/H	0			
LA-0246	ST. CHARLES REFINERY	LA	12/31/2010 ACT	MVR Thermal Oxidizers (EQT0350 and EQT0351)		240	MMBTU/H	Sulfur Dioxide (SO2)	Natural gas, Refinery Fuel Gas, or process fuel gas with H2S <=100 ppv (annual average)	15.1	LB/H	0			
MA-0027	CABOT POWER CORPORATION	MA	05/07/2000 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS	NATURAL GAS	2493	MMBTU/H	Sulfur Dioxide (SO2)	CLEAN FUEL - NATURAL GAS WITH 8 GRAINS SULFUR PER 100 SCF.	5.9	LB/H	0			
MA-0027	CABOT POWER CORPORATION	MA	05/07/2000 ACT	AUXILIARY BOILER	NATURAL GAS	26.6	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL OF < .8 GRAINS PER 100 SCF.	0.06	LB/H	0.0022	LB/MMBTU		
MA-0029	SITHE MYSTIC DEVELOPMENT LLC	MA	09/29/1999 EST	IC ENGINE, EMERGENCY DIESEL GENERATOR	DIESEL	1500	KW	Sulfur Dioxide (SO2)	SULFUR CONTENT THAT DOES NOT EXCEED .05% BY WEIGHT, LIMITED TO CONSUMPTION OF 8 250 GALLONS BASED ON 75 HOURS OF OPERATION PER 12 MONTH ROLLING PERIOD.	0.95	LB/H	0.17	G/BHP-H		
MA-0029	SITHE MYSTIC DEVELOPMENT LLC	MA	09/29/1999 EST	BOILER, AUXILIARY	NATURAL GAS	96	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL WITH NO MORE THAN .8 GRAINS OF SULFUR PER 100 CU FT.	0.3	LB/H	0.0029	LB/MMBTU		
MA-0029	SITHE MYSTIC DEVELOPMENT LLC	MA	09/29/1999 EST	TURBINE, COMBINED CYCLE, NATURAL GAS (2)	NATURAL GAS	2699	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR CONTENT IN FUEL - NO MORE THAN 8 GRAINS PER 100 CU FT.	8.6	LB/H	150	PPM @ 15% O2		listed standardized limit is nsps limit.
MD-0040	CPV ST CHARLES	MD	11/12/2008 ACT	INTERNAL COMBUSTION ENGINE - EMERGENCY FIRE WATER PUMP	DIESEL	300	HP	Sulfur Dioxide (SO2)		0		0			EXCLUSIVE USE OF ULTRA LOW SULFUR DIESEL FUEL WITH A SULFUR CONTENT NOT TO EXCEED 15 PARTS PER MILLION BY WEIGHT
MD-0040	CPV ST CHARLES	MD	11/12/2008 ACT	HEATER	NATURAL GAS	1.7	MMBTU/H	Sulfur Dioxide (SO2)		0		0			EXCLUSIVE USE OF NATURAL GAS WITH SULFUR CONTENT NOT TO EXCEED 2.0 GR/100 SCF
MI-0301	ALCHEM ALUMINUM	MI	05/02/2000 ACT	SIDE-WELLS	NATURAL GAS	42000	LB/H	Sulfur Dioxide (SO2)	SIDE WELL EMISSIONS PASS THROUGH LIME-INJECTED BAGHOUSES. NO CONTROL CLAIMED, %.	0.52	LB/H	0	LB/MMBTU		
MI-0301	ALCHEM ALUMINUM	MI	05/02/2000 ACT	CRUSHER	NA	20000	LB/H	Sulfur Dioxide (SO2)	N/A	1.47	LB/H	0	LB/MMBTU		
MI-0301	ALCHEM ALUMINUM	MI	05/02/2000 ACT	CRUCIBLE HEATERS/STATIONS	NATURAL GAS	2	MMBTU/H EACH	Sulfur Dioxide (SO2)	N/A	0.01	LB/H	0		NOT AVAILABLE	
MI-0301	ALCHEM ALUMINUM	MI	05/02/2000 ACT	FLUES	NATURAL GAS	42000	LB/H	Sulfur Dioxide (SO2)	COMBUSTION FLUES ARE WITHOUT ADD-ON CONTROLS. ONLY PIPELINE QUALITY NATURAL GAS FOR FUEL.	0.12	LB/H	0	LB/MMBTU		
MN-0053	FAIRBAULT ENERGY PARK	MN	07/15/2004 ACT	IC ENGINE, SMALL, FUEL OIL (1)	DIESEL	250	HP	Sulfur Dioxide (SO2)	LOW SULFUR FUEL.	0 051	LB/MMBTU	0			
MN-0053	FAIRBAULT ENERGY PARK	MN	07/15/2004 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS (1)	NATURAL GAS	1876	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL.	0.8	GR/SCF	0			
MN-0053	FAIRBAULT ENERGY PARK	MN	07/15/2004 ACT	TURBINE, COMBINED CYCLE, DISTILLATE OIL (1)	#2 DISTILLATE OIL	1801	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL.	0 051	LB/MMBTU	0			EMISSION LIMIT 1 IS EQUAL TO 0 05% S BY WEIGHT.
MN-0053	FAIRBAULT ENERGY PARK	MN	07/15/2004 ACT	BOILER, NATURAL GAS (1)	NATURAL GAS	40	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL 0.8 GR/SCF, CALENDAR YEAR AVERAGE	0		0			BACT is fuel sulfur limit.
MN-0053	FAIRBAULT ENERGY PARK	MN	07/15/2004 ACT	BOILER, DISTILLATE OIL (1)	#2 FUEL OIL	40	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL.	0 051	LB/MMBTU	0.051	LB/MMBTU		EMISSION LIMIT 1 EQUALS TO 0 05% S BY WEIGHT.
MN-0053	FAIRBAULT ENERGY PARK	MN	07/15/2004 ACT	IC ENGINE, LARGE, FUEL OIL (1)	DIESEL	670	HP	Sulfur Dioxide (SO2)	LOW SULFUR FUEL.	0 051	LB/MMBTU	0			
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	INTERNAL COMBUSTION ENGINE, LARGE	DIESEL FUEL	1850	HP	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.59	G/B-HP-H	0			
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	INTERNAL COMBUSTION ENGINE, SMALL	DIESEL FUEL	290	HP	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.14	G/B-HP-H	0			

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MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	COMBUSTION TURBINE, LARGE 2 EACH	NATURAL GAS	1827	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFLUR FUEL	0.05	% S BY WT	0			LIMIT APPLIES TO OIL SULFUR CONENT
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	DUCT BURNER, 2 EACH	NATURAL GAS	800	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.8	GR/100SCF	0		NOT AVAILABLE	LIMIT IS FOR SULFUR CONTENT OF NG
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	COMBUSTION TURBINE, LARGE, 2 EACH	NATURAL GAS	1916	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.8	GR/100SCF	0			LIMIT IS FOR SULFUR CONENT OF NG
MN-0054	MANKATO ENERGY CENTER	MN	12/04/2003 ACT	BOILER, COMMERCIAL	NATURAL GAS	70	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0 001	LB/MMBTU	0.001	LB/MMBTU		
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	LADLE PREHEATER	NATURAL GAS	48	MMBTU/H	Sulfur Dioxide (SO2)		346.59	LB/T	0			
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	NNI REHEAT FURNACE	NATURAL GAS	133	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	NNII REHEAT FURNACE	NATURAL GAS	143	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	NNII BILET POST-HEATER	NATURAL GAS	6.8	MMBTU/H	Sulfur Dioxide (SO2)		0.0006	LB/MMBTU	0			
NE-0026	NUCOR STEEL DIVISION	NE	06/22/2004 EST	CUT-OFF TORCHES	NATURAL GAS			Sulfur Dioxide (SO2)		2.25	LB/T	0			
NJ-0036	AES RED OAK LLC	NJ	10/24/2001 ACT	AUXILIARY BOILER- DISTILLATE OIL	DISTILLATE FUEL OIL	99	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR OIL (NO PERCENTAGES GIVEN)	5 021	LB/H	0.0507	LB/MMBTU		
NJ-0036	AES RED OAK LLC	NJ	10/24/2001 ACT	FUEL GAS HEATER	NATURAL GAS	16	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL	0 069	LB/H	0.0043	LB/MMBTU		
NJ-0036	AES RED OAK LLC	NJ	10/24/2001 ACT	AUXILIARY BOILER	NATURAL GAS	120	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL	0 514	LB/H	0.0043	LB/MMBTU		
NJ-0036	AES RED OAK LLC	NJ	10/24/2001 ACT	EMERGENCY GENERATOR	DIESEL FUEL	49	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	2.45	LB/H	0			
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 4 (NAT GAS)	NATURAL GAS	118	MMBTU/H	Sulfur Dioxide (SO2)	NONE LISTED	0.1	LB/H	0.0008	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 1 (NO. 2 OIL)	NATURAL GAS	84.4	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL- 0.05% BY WEIGHT	4.3	LB/H	0.051	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 2 (NAT GAS)	NATURAL GAS	134	MMBTU/H	Sulfur Dioxide (SO2)	NONE LISTED	0.1	LB/H	0.0007	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 3 (NAT GAS)	NATURAL GAS	152	MMBTU/H	Sulfur Dioxide (SO2)	NONE LISTED	0.1	LB/H	0.0007	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 3 (NO. 2 OIL)	NAT GAS	241.6	MMBTU/H	Sulfur Dioxide (SO2)	LIMITED OPERATING HOURS FOR NO. 2 OIL; FUEL SULFUR LIMIT OF 0 05% BY WEIGHT.	12.4	LB/H	0.0513	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 2 (NO. 2 OIL)	NAT GAS	230.8	MMBTU/H	Sulfur Dioxide (SO2)	LIMITED OPERATING HOURS FOR NO. 2 OIL, FUEL SULFUR LIMIT OF 0 05% BY WEIGHT.	11.9	LB/H	0.0516	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 4 (NO. 2 OIL)	NAT GAS	204.2	MMBTU/H	Sulfur Dioxide (SO2)	LIMITED OPERATING HOURS FOR NO. 2 OIL; FUEL SULFUR LIMIT OF 0 05% BY WEIGHT.	10.5	LB/H	0.0514	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 1 (NATURAL GAS)	NATURAL GAS	84.4	MMBTU/H	Sulfur Dioxide (SO2)	NONE LISTED	0.1	LB/H	0.001	LB/MMBTU		
NJ-0042	ROCHE VITAMINS	NJ	02/05/1999 ACT	BOILER 1 (LASALOCID OIL & NO. 2 OIL COMBINED)	NATURAL GAS	35.5	MMBTU/H	Sulfur Dioxide (SO2)	LIMITED OPERATING HOURS FOR NO. 2 OIL; NO. 2 OIL LIMITED TO 0.05% SULFUR BY WEIGHT.	2.8	LB/H	0.079	LB/MMBTU		
NJ-0062	CONSOLIDATE EDISON DEVELOPMENT (CED)	NJ	10/22/2002 ACT	FUEL GAS HEATERS (3 UNITS)	NATURAL GAS	4.62	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL.	0 014	LB/H	0			
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	07/25/2012 ACT	Commercial/Institutional size boilers less than 100 MMBtu/hr	natural gas	2000	hours/year	Sulfur Dioxide (SO2)	Use of natural gas	0.162	LB/H	0			
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	07/25/2012 ACT	Combined Cycle Combustion Turbine with Duct Burner	Natural gas	40297.6	mmcubic ft/year	Sulfur Dioxide (SO2)	Good Combustion Practices and use of Natural gas,a clean burning fuel.	4.9	LB/H	0			
NJ-0079	WOODBRIDGE ENERGY CENTER	NJ	07/25/2012 ACT	Combined Cycle Combustion Turbine w/o duct burner	natural gas	40297.6	mmcubic ft/year	Sulfur Dioxide (SO2)	Use of only natural gas a clean burning fuel	4.1	LB/H	0			
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/01/2012 ACT	Combined cylce turbine with duct burner	natural gas	39463	mmcubic ft/year*	Sulfur Dioxide (SO2)	Use of natural gas, a clean low sulfur fuel	2.5	LB/H	0			
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/01/2012 ACT	Boiler less than 100 MMBtu/hr	Natural Gas	51.9	mmcubic ft/year	Sulfur Dioxide (SO2)	use of natural gas a clean fuel and a low sulfur fuel	0.08	LB/H	0			Stack testing for SO2 not required due to extremely low emissions
NJ-0080	HESS NEWARK ENERGY CENTER	NJ	11/01/2012 ACT	Combined Cycle Combustion Turbine	natural gas	39463	MMCubic ft/yr	Sulfur Dioxide (SO2)	Use of natural gas a clean low sulfur fuel	2.8	LB/H	0			
NM-0044	CLOVIS ENERGY FACILITY	NM	06/27/2002 ACT	AUXILIARY BOILERS (AUX-1 AND AUX-2)	NATURAL GAS	33	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS, GOOD COMBUSTION PRACTICE	0.1	LB/H	0.003	LB/MMBTU	calculated	
NM-0044	CLOVIS ENERGY FACILITY	NM	06/27/2002 ACT	TURBINES, COMBINED CYCLE, NATURAL GAS (4)	NATURAL GAS	1515	MMBTU/H	Sulfur Dioxide (SO2)	PIPELINE QUALITY NATURAL GAS, GOOD ENGINEERING PRACTICE	4.3	LB/H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
NM-0044	CLOVIS ENERGY FACILITY	NM	06/27/2002 ACT	DUCT BURNERS (DB-1 AND DB-2)	NATURAL GAS	643	MMBTU/H	Sulfur Dioxide (SO2)	PIPELINE QUALITY NATURAL GAS, GOOD COMBUSTION PRACTICE.	1.5	LB/H	0.002	LB/MMBTU	calculated	
NV-0037	COPPER MOUNTAIN POWER	NV	05/14/2004 ACT	LARGE COMBUSTION TURBINES, COMBINED CYCLE & COGENERATION	NATURAL GAS	600	MW	Sulfur Dioxide (SO2)	USE OF CLEAN-BURNING, LOW-SULFUR, PIPELINE-QUALITY NATURAL GAS	5.1	LB/H	0			EMISSION LIMIT 1 IS FOR EACH TURBINE/DUCT BURNER PAIR.
NV-0037	COPPER MOUNTAIN POWER	NV	05/14/2004 ACT	AUXILIARY BOILER	NATURAL GAS	60	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW-SULFUR NATURAL GAS	0.04	LB/H	0			
NV-0039	CHUCK LENZIE GENERATING STATION	NV	06/01/2001 ACT	LARGE COMBUSTION TURBINE - COMBINED CYCLE	NATURAL GAS	1170	MW	Sulfur Dioxide (SO2)	USE OF PIPE-LINE QUALITY NATURAL GAS	4.78	LB/H	0			EMISSION LIMIT 1 APPLIES TO EACH COMBUSTION TURBINE GENERATOR WITH DUCT-FIRING.
NV-0039	CHUCK LENZIE GENERATING STATION	NV	06/01/2001 ACT	AUXILIARY BOILERS	NATURAL GAS	44.1	MMBTU/H	Sulfur Dioxide (SO2)	USE OF PIPELINE-QUALITY NATURAL GAS	0.4	LB/H	0.009	LB/MMBTU		EMISSION LIMIT 1 APPLIES TO EACH AUXILIARY BOILER.
NV-0046	GOODSPRINGS COMPRESSOR STATION	NV	05/16/2006 ACT	LARGE COMBUSTION TURBINE - SIMPLE CYCLE	NATURAL GAS	97 81	MMBTU/H	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS IS THE ONLY FUEL FOR THE PROCESS.	0.0034	LB/MMBTU	0.0034	LB/MMBTU	15% OXYGEN	THE EMISSION LIMITS APPLY TO EACH OF THE THREE TURBINES.
NV-0046	GOODSPRINGS COMPRESSOR STATION	NV	05/16/2006 ACT	COMMERCIAL/INSTITUTIONAL BOILER	NATURAL GAS	3 85	MMBTU/H	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS IS THE ONLY FUEL FOR THE PROCESS.	0.0026	LB/MMBTU	0.0026	LB/MMBTU		
NV-0047	NELLIS AIR FORCE BASE	NV	02/26/2008 ACT	BOILERS/HEATERS - NATURAL GAS-FIRED	NATURAL GAS			Sulfur Dioxide (SO2)	USE OF PIPELINE-QUALITY NATURAL GAS	0.0015	LB/MMBTU	0.0015	LB/MMBTU		
NV-0047	NELLIS AIR FORCE BASE	NV	02/26/2008 ACT	BOILERS/HEATERS - DIESEL OIL-FIRED	DIESEL OIL			Sulfur Dioxide (SO2)	LIMITING SULFUR CONTENT IN THE DIESEL OIL TO 0.05% BY WEIGHT	0.0094	LB/MMBTU	0.0094	LB/MMBTU		
NV-0047	NELLIS AIR FORCE BASE	NV	02/26/2008 ACT	AIRCRAFT ENGINE TESTING	JP-8	11490	LB/H	Sulfur Dioxide (SO2)	SULFUR CONTENT IN THE LIQUID FUEL (JP-8) IS LIMITED TO 0.05%.	0.5	LB/1000 LB FUEL	0			
NV-0047	NELLIS AIR FORCE BASE	NV	02/26/2008 ACT	LARGE INTERNAL COMBUSTION ENGINES (>500 HP)	DIESEL OIL			Sulfur Dioxide (SO2)	LIMITING SULFUR CONTENT IN THE DIESEL OIL TO 0.05%	0.02	G/B-HP-H	0			
NV-0047	NELLIS AIR FORCE BASE	NV	02/26/2008 ACT	SMALL INTERNAL COMBUSTION ENGINES (<= 500 HP)	DIESEL OIL			Sulfur Dioxide (SO2)	LIMITING SULFUR CONTENT IN THE DIESEL OIL TO 0.05%	0.99	G/B-HP-H	0 99	G/B-HP-H		
NV-0047	NELLIS AIR FORCE BASE	NV	02/26/2008 ACT	AIRCRAFT ARRESTORS	GASOLINE			Sulfur Dioxide (SO2)	USE OF LOW-SULFUR GASOLINE	0.28	G/B-HP-H	0 28	G/B-HP-H		
NV-0047	NELLIS AIR FORCE BASE	NV	02/26/2008 ACT	MEDICAL WASTE INCINERATOR	NATURAL GAS			Sulfur Oxides (SOx)	USE OF NATURAL GAS AS THE FUEL	0.05	LB/H	0			
NV-0047	NELLIS AIR FORCE BASE	NV	02/26/2008 ACT	ASPHALT CONCRETE MANUFACTURING	N/A			Sulfur Dioxide (SO2)	GOOD OPERATING PRACTICE	1.38	LB/H	0			
NV-0048	GOODSPRINGS COMPRESSOR STATION	NV	05/16/2006 ACT	SIMPLE-CYCLE SMALL COMBUSTION TURBINES (<25 MW)	NATURAL GAS	11.5	MW	Sulfur Dioxide (SO2)	USING LOW-SULFUR NATURAL GAS ONLY	0.0034	LB/MMBTU	0.0034	LB/MMBTU		THE EMISSION LIMITS APPLY TO EACH TURBINE.
NV-0048	GOODSPRINGS COMPRESSOR STATION	NV	05/16/2006 ACT	COMMERCIAL/INSTITUTIONAL-SIZE BOILER (<100 MMBTU/H)	NATURAL GAS	3 85	MMBTU/H	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS IS THE ONLY FUEL USED BY THE UNIT.	0.0015	LB/MMBTU	0.0015	LB/MMBTU		THE EMISSION LIMITS ARE BASED ON THE EMISSION FACTOR LISTED IN AP-42.
NV-0048	GOODSPRINGS COMPRESSOR STATION	NV	05/16/2006 ACT	LARGE INTERNAL COMBUSTION ENGINE (>500 HP)	NATURAL GAS	5 91	MMBTU/H	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS IS THE ONLY FUEL USED BY THE UNIT.	0.0052	G/B-HP-H	0.0052	G/B-HP-H		THE EMISSION LIMITS ARE BASED ON THE EMISSION FACTOR LISTED IN AP-42.
NY-0095	CAITHNES BELLPORT ENERGY CENTER	NY	05/10/2006 ACT	AUXILIARY BOILER	DISTILLATE OIL	28	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL (0.04%).	0 041	LB/MMBTU	0			
NY-0095	CAITHNES BELLPORT ENERGY CENTER	NY	05/10/2006 ACT	COMBUSTION TURBINE	NATURAL GAS	2221	MMBUT/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.0011	LB/MMBTU	0			
NY-0095	CAITHNES BELLPORT ENERGY CENTER	NY	05/10/2006 ACT	COMBUSTION TURBINE	#2 DISTILLATE OIL	2125	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0 042	LB/MMBTU	0			
NY-0095	CAITHNES BELLPORT ENERGY CENTER	NY	05/10/2006 ACT	AUXILIARY BOILER	NATURAL GAS	29.4	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.0005	LB/MMBTU	0			
OH-0248	LAWRENCE ENERGY	OH	09/24/2002 ACT	TURBINES (3), COMBINED CYCLE, DUCT BURNERS OFF	NATURAL GAS	180	MW	Sulfur Oxides (SOx)	BURNING NATURAL GAS	11.9	LB/H	0			Limits for each turbine.
OH-0248	LAWRENCE ENERGY	OH	09/24/2002 ACT	TURBINES (3), COMBINED CYCLE, DUCT BURNERS ON	NATURAL GAS	180	MW	Sulfur Oxides (SOx)	BURNING NATURAL GAS	16.1	LB/H	0			Limits are for one turbine. Additional limit: 11 9 lbs/hr without duct burner
OH-0248	LAWRENCE ENERGY	OH	09/24/2002 ACT	BOILER	NATURAL GAS	99	MMBTU/H	Sulfur Dioxide (SO2)		0.56	LB/H	0.0057	LB/MMBTU		Limits are for each boiler.
OH-0251	CENTRAL SOYA COMPANY INC.	OH	11/29/2001 ACT	DRYER, SOY PROTEIN CONCENTRATE - COMBUSTION	NATURAL GAS	37	MMBTU/H	Sulfur Dioxide (SO2)		0 021	LB/H	0.0006	LB/MMBTU		Emissions from natural gas combustion, using 0.0006 lb SO2/mmBtu
OH-0251	CENTRAL SOYA COMPANY INC.	OH	11/29/2001 ACT	BOILER, NO 2 FUEL OIL	NO 2 FUEL OIL	91.2	MMBTU/H	Sulfur Dioxide (SO2)		18.2	LB/H	0 21	LB/MMBTU	calculated	Using AP-42 emission factor of 0.6 lb/million cubic feet and manufacturer's data 0.21 lb SO2/mmBtu on #2 fuel oil or may opt for burning oil with no greater than 0.5 weight % sulfur. For each shipment of oil, the supplier shall provide the sulfur content and heat content from analytical results from testing. Additional limit: 26.2 tons/rolling 12 months when using No 2 fuel oil.
OH-0251	CENTRAL SOYA COMPANY INC.	OH	11/29/2001 ACT	BOILER, NATURAL GAS	NATURAL GAS	91.2	MMBTU/H	Sulfur Dioxide (SO2)		0 055	LB/H	0.0006	LB/MMBTU		Using AP-42 emission factor of 0.6 lb/million cubic feet
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	OH	12/28/2004 ACT	TURBINES (4) (MODEL GE 7FA), DUCT BURNERS ON	NATURAL GAS	172	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL: MAXIMUM S CONTENT OF NATURAL GAS SHALL NOT EXCEED 2 GRAINS/100 SCF	14.4	LB/H	0			LIMIT IS FOR EACH TURBINE. EACH TURBINE HAS A LIMIT OF 52 82 TONS OF SO2/ROLLING 12-MONTHS; SEE PROCESS NOTES FOR RESTRICTIONS ON DUCT BURNERS AND STARTUPS.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	OH	12/28/2004 ACT	TURBINES (4) (MODEL GE 7FA), DUCT BURNERS OFF	NATURAL GAS	172	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL: MAXIMUM S CONTENT OF NATURAL GAS SHALL NOT EXCEED 2 GRAINS/100 SCF	11	LB/H	0			LIMIT IS FOR EACH TURBINE. EACH TURBINE HAS A LIMIT OF 52 82 TONS OF SO2/ROLLING 12-MONTHS; SEE PROCESS NOTES FOR RESTRICTIONS ON DUCT BURNERS AND STARTUPS.
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	OH	12/28/2004 ACT	BACKUP GENERATORS (2)	DIESEL	500	KW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.27	LB/H	0.18	G/B-HP-H		
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	OH	12/28/2004 ACT	FIRE WATER PUMP (1)	DIESEL	265	HP	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.1	LB/H	0.16	G/B-HP-H		
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	OH	12/28/2004 ACT	BOILERS (2)	NATURAL GAS	30.6	MMBTU/H	Sulfur Dioxide (SO2)	THE MAXIMUM S CONTENT OF THE NATURAL GAS SHALL NOT EXCEED 2 GRAINS PER 100 CUBIC FEET.	0 031	LB/H	0.001	LB/MMBTU		LIMITS ARE FOR EACH BOILER.
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	OH	08/14/2003 ACT	BOILER	NATURAL GAS	30.6	MMBTU/H	Sulfur Dioxide (SO2)		0 031	LB/H	0.001	LB/MMBTU		
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	OH	08/14/2003 ACT	EMERGENCY DIESEL-FIRED GENERATOR	DIESEL	600	KW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, COMBUSTION CONTROL	0.4	LB/H	0 23	G/B-HP-H		
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	OH	08/14/2003 ACT	EMERGENCY DIESEL FIRE PUMP ENGINE	DIESEL	400	HP	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, COMBUSTION CONTROL	0.84	LB/H	0 95	G/B-HP-H		
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	OH	08/14/2003 ACT	TURBINES (2) (MODEL GE 7FA), DUCT BURNERS ON	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL - LOW S NATURAL GAS 2 GR/100 SCF	14.5	LB/H	0			LIMIT IS FOR EACH TURBINE. EACH TURBINE HAS A LIMIT OF 56 5 TONS OF SO2/ROLLING 12-MONTHS; SEE PROCESS NOTES FOR RESTRICTIONS ON DUCT BURNERS AND STARTUPS.
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	OH	08/14/2003 ACT	TURBINES (2) (MODEL GE 7FA), DUCT BURNERS OFF	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)	LOW S NATURAL GAS 2 GR/100 SCF	11.2	LB/H	0			LIMIT IS FOR EACH TURBINE. EACH TURBINE HAS A LIMIT OF 56 5 TONS OF SO2/ROLLING 12-MONTHS; SEE PROCESS NOTES FOR RESTRICTIONS ON DUCT BURNERS AND STARTUPS.
OH-0255	AEP WATERFORD ENERGY LLC	OH	03/29/2001 ACT	TURBINES (3), COMBINED CYCLE, W/ DUCT FIRING	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)		14	LB/H	0			LIMITS FOR EACH TURBINE.
OH-0255	AEP WATERFORD ENERGY LLC	OH	03/29/2001 ACT	COMBUSTION TURBINES (3), SIMPLE CYCLE	NATURAL GAS	170	MW	Sulfur Dioxide (SO2)		12	LB/H	0			Limits are for each turbine.
OH-0255	AEP WATERFORD ENERGY LLC	OH	03/29/2001 ACT	EMERGENCY GENERATOR	DIESEL	1000	KW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.01	T/YR	0			Unit limited to 500 hours per 12 month period.
OH-0255	AEP WATERFORD ENERGY LLC	OH	03/29/2001 ACT	FIRE WATER PUMP	DIESEL	290	KW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0 003	T/YR	0			Unit limited to 500 hours per 12 month period.
OH-0255	AEP WATERFORD ENERGY LLC	OH	03/29/2001 ACT	BOILER, NATURAL GAS	NATURAL GAS	85.2	MMBTU/H	Sulfur Dioxide (SO2)	LOW S NATURAL GAS, 2 GR/100 SCF	0.05	LB/H	0.0006	LB/MMBTU		
OH-0257	JACKSON COUNTY POWER, LLC	OH	12/27/2001 ACT	COMBUSTION TURBINES, COMBINED CYCLE, (4)	NATURAL GAS	305	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL - 2 GR/100 SCF	15.3	LB/H	0			Limits are for each turbine.
OH-0257	JACKSON COUNTY POWER, LLC	OH	12/27/2001 ACT	AUXILIARY BOILER	NATURAL GAS	76	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, NATURAL GAS SULFUR LIMIT - 2 GR/100 SCF	0.5	LB/H	0.006	LB/MMBTU		Additional limit: 2 grains/100 scf natural gas
OH-0263	FREMONT ENERGY CENTER, LLC	OH	08/09/2001 ACT	COMBUSTION TURBINES(2), COMB CYCLE W/O DUCT BURNER	NATURAL GAS	180	MW	Sulfur Dioxide (SO2)		11.9	LB/H	0			Limit is for each turbine. Additional limits: 65 8 T/YR
OH-0263	FREMONT ENERGY CENTER, LLC	OH	08/09/2001 ACT	COMBUSTION TURBINES (2), COMB CYCLE W DUCT BURNER	NATURAL GAS	180	MW	Sulfur Dioxide (SO2)		16.1	LB/H	0			Limit is for each turbine. Additional limit: 65 8 T/YR
OH-0263	FREMONT ENERGY CENTER, LLC	OH	08/09/2001 ACT	AUXILIARY BOILER	NATURAL GAS	80	MMBTU/H	Sulfur Dioxide (SO2)		0.48	LB/H	0.006	LB/MMBTU		
OH-0264	NORTON ENERGY STORAGE, LLC	OH	05/23/2002 ACT	COMBUSTION TURBINE (9), COMB CYCLE W/O DUCT BURNER	NATURAL GAS	300	MW	Sulfur Dioxide (SO2)		1.98	LB/H	0			Limits are for each turbine. Limited to 4,160 hours per year.
OH-0264	NORTON ENERGY STORAGE, LLC	OH	05/23/2002 ACT	COMBUSTION TURBINES (9), COMB CYCLE W DUCT BURNER	NATURAL GAS	300	MW	Sulfur Dioxide (SO2)		2.55	LB/H	0			Limits are for each turbine. Limited to 4,160 hours per year.
OH-0264	NORTON ENERGY STORAGE, LLC	OH	05/23/2002 ACT	RECUPERATOR PRE-HEATERS (9)	NATURAL GAS	12 84	MMBTU/H	Sulfur Dioxide (SO2)	THE MAXIMUM SULFUR CONTENT OF THE NATURAL GAS SHALL NOT EXCEED 0.6 GRAINS PER 100 STANDARD CUBIC FEET.	0 023	LB/H	0.002	LB/MMBTU		Limits are for each boiler. Each boiler is retricted to 100 hours of operation.
OH-0264	NORTON ENERGY STORAGE, LLC	OH	05/23/2002 ACT	FUEL SUPPLY HEATERS (9)	NATURAL GAS	11.45	MMBTU/H	Sulfur Dioxide (SO2)	THE MAXIMUM SULFUR CONTENT OF THE NATURAL GAS SHALL NOT EXCEED 0.6 GRAINS PER 100 STANDARD CUBIC FEET.	0 021	LB/H	0.002	LB/MMBTU		Limits are for each heater.
OH-0265	DRESDEN ENERGY LLC	OH	10/16/2001 ACT	COMBUSTION TURBINE (2), COMB. CYCLE W/O DUCT BURN	#2 DIS. FUEL OIL	171.7	MW	Sulfur Dioxide (SO2)	THE MAXIMUM SULFUR CONTENT OF FUEL OIL SHALL NOT EXCEED 0.05% SULFUR BY WEIGHT.	101	LB/H	0			Limits are for each turbine. Additional limit: Turbines are restricted to 500 hrs/yr on fuel oil.
OH-0265	DRESDEN ENERGY LLC	OH	10/16/2001 ACT	COMBUSTION TURBINE (2), COMB. CYCLE W DUCT BURN	NATURAL GAS	171.7	MW	Sulfur Dioxide (SO2)	THE MAXIMUM SULFUR CONTENT OF NG SHALL NOT EXCEED 3 GRAINS/100SCF	1.8	LB/H	0			Limits are for each turbine. Additional limit: Turbines are limited to 2000 hrs/yr w/ duct burners.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
OH-0265	DRESDEN ENERGY LLC	OH	10/16/2001 ACT	COMBUSTION TURBINE (2), COMB. CYCLE W/O DUCT BURN	NATURAL GAS	171.7	MW	Sulfur Dioxide (SO2)	THE MAXIMUM SULFUR CONTENT OF NG SHALL NOT EXCEED 0 3 GRAINS/100 SCF.	1.6	LB/H	0			Limits are for each turbine. Additional limit: Turbines are limited to 6260 hrs/yr w/o duct burners on NG.
OH-0265	DRESDEN ENERGY LLC	OH	10/16/2001 ACT	BOILER, NATURAL GAS	NATURAL GAS	49	MMBTU/H	Sulfur Dioxide (SO2)	THE MAXIMUM SULFUR CONTENT OF THE NATURAL GAS SHALL NOT EXCEED 0.3 GRAINS PER 100 STANDARD CUBIC FEET.	0.05	LB/H	0.001	LB/MMBTU		Boiler is restricted to 800 hours or operation per a rolling 12 months.
OH-0276	CHARTER STEEL	OH	06/10/2004 ACT	ELECTRIC ARC FURNACE	ELECTRIC	110	T/H MELT	Sulfur Dioxide (SO2)	PRODUCTION LIMITS. SEE NOTE	22	LB/H	0.2	LB/T		CUYAHOGA COUNTY WAS NON-ATTAINMENT FOR SO2 AT THE TIME THE PERMIT WAS ISSUED; THIS PERMIT WAS A SYNTHETIC MINOR FOR SO2 AT 99 53 TONS; WITH RESTRICTIONS ON PRODUCTION: 710,600 TONS OF STEEL AND 28,000 TONS OF RESULFURIZATION GRADE STEEL. ADDITIONAL LIMITS: FROM ELECTRIC ARC FURNACE AND LADLE METALLURGY FURNACE TOGETHER: 71.06 T/ROLLING 12-MO FROM ALL GRADES OF STEEL EXCEPT RESULFURIZED GRADES. 0 2 LB SO2 EMISSION FACTOR PER TON OF STEEL
OH-0276	CHARTER STEEL	OH	06/10/2004 ACT	LADLE METALLURGY FURNACE	ELECTRIC	110	T/H	Sulfur Dioxide (SO2)		220	LB/H	0			CUYAHOGA COUNTY WAS NON-ATTAINMENT FOR SO2 AT THE TIME THE PERMIT WAS ISSUED; THIS PERMIT WAS A SYNTHETIC MINOR FOR SO2 AT 99 53 TONS; WITH RESTRICTIONS ON PRODUCTION: 710,600 TONS OF STEEL AND 28,000 TONS OF RESULFURIZATION GRADE STEEL. ADDITIONAL LIMITS: 28.0 T/ROLLING 12-MO FROM RESULFURIZED GRADE STEEL; AND FROM ELECTRIC ARC FURNACE AND LADLE METALLURGY FURNACE TOGETHER: 71.06 T/ROLLING 12-MO FROM ALL GRADES OF STEEL EXCEPT RESULFURIZED GRADES.
OH-0276	CHARTER STEEL	OH	06/10/2004 ACT	TUNDISH PREHEATER, 3 UNITS	NATURAL GAS	12	MMBTU/H	Sulfur Dioxide (SO2)		0 007	LB/H	0			LIMIT IS FOR EACH UNIT; LIMIT TIMES 3 EQUALS TOTAL EMISSIONS FROM ALL TUNDISH PREHEATERS
OH-0276	CHARTER STEEL	OH	06/10/2004 ACT	VACUUM OXYGEN DEGASSER VESSEL W/ FLARE	STEAM	150	T/H STEEL	Sulfur Dioxide (SO2)		0 009	LB/H	0			EMISSIONS FROM NATURAL GAS COMBUSTION FROM FLARE; ONLY DURING OXYGEN LANCING DEGASSING PROCESS FOR LOW CARBON AND STAINLESS STEEL PRODUCTION.
OH-0276	CHARTER STEEL	OH	06/10/2004 ACT	BOILER FOR VACUUM OXYGEN DEGASSER VESSEL	NATURAL GAS	28.6	MMBTU/H	Sulfur Dioxide (SO2)		0.02	LB/H	0		NOT AVAILABLE	
OH-0276	CHARTER STEEL	OH	06/10/2004 ACT	LADLE PREHEATER AND DRYER, 4 UNITS	NATURAL GAS	10	MMBTU/H	Sulfur Dioxide (SO2)		0 006	LB/H	0			LIMITS ARE FOR EACH PREHEATER; LIMIT TIMES 4 EQUALS TOTAL EMISSIONS FROM ALL PREHEATERS
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	OH	05/03/2007 ACT	BOILER (2), NATURAL GAS	NATURAL GAS	20.4	MMBTU/H	Sulfur Dioxide (SO2)		0.01	LB/H	0.0006	LB/MMBTU		LIMITS ARE FOR EACH BOILER.
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	OH	05/03/2007 ACT	BOILER (2), NO. 2 FUEL OIL	FUEL OIL #2	20.4	MMBTU/H	Sulfur Dioxide (SO2)		10.4	LB/H	0 51	LB/MMBTU		LIMITS ARE FOR EACH BOILER.
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	OH	05/03/2007 ACT	AIR SUPPLY MAKE UP UNITS (24)	NATURAL GAS	20	MMBTU/H	Sulfur Dioxide (SO2)		0.02	LB/H	0.0006	LB/MMBTU		LIMITS ARE FOR EACH UNIT. 24 AIR SUPPLY MAKE UP UNITS.
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	OH	05/03/2007 ACT	AIR SUPPLY MAKE UP UNITS	NATURAL GAS	28 95	MMBTU/H	Sulfur Dioxide (SO2)		0.02	LB/H	0.0006	LB/MMBTU		
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	OH	05/03/2007 ACT	AIR SUPPLY MAKE UP UNITS (6)	NATURAL GAS	14	MMBTU/H	Sulfur Dioxide (SO2)		0.01	LB/H	0.0006	LB/MMBTU		LIMITS ARE FOR EACH UNIT. 6 AIR SUPPLY UNITS.
*OH-0355	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	OH	05/07/2013 ACT	Test Cell 1 for Aircraft Engines and Turbines	JET FUEL	0		Sulfur Dioxide (SO2)		0.11	LB/MMBTU	0			T/YR limit is in rolling 12-months and is total for both test cells and their 4 preheaters. Must develop an Emissions Protocol Document on the potential to emit.
*OH-0355	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	OH	05/07/2013 ACT	Test Cell 2 for Aircraft Engines and Turbines	JET FUEL	0		Sulfur Dioxide (SO2)		0.11	LB/MMBTU	0			T/YR limit is in rolling 12-months and is total for both test cells and their 4 preheaters. Must develop an Emissions Protocol Document on the potential to emit.
*OH-0355	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	OH	05/07/2013 ACT	4 Indirect-Fired Air Preheaters	Natural gas	0		Sulfur Dioxide (SO2)		0 001	LB/MMBTU	0			T/YR limit is in rolling 12-months and is total for both test cells and their 4 preheaters. Must develop an Emissions Protocol Document on the potential to emit.
OK-0043	WEBERS FALLS ENERGY FACILITY	OK	10/22/2001 ACT	AUXILIARY BOILER	NATURAL GAS	30	MMBTU/H	Sulfur Dioxide (SO2)	USE OF NATURAL GAS	150	PPM	0		NOT AVAILABLE	
OK-0043	WEBERS FALLS ENERGY FACILITY	OK	10/22/2001 ACT	COMBUSTION TURBINES	NATURAL GAS			Sulfur Dioxide (SO2)	USE OF NATURAL GAS	0 006	LB/MMBTU	0			
OK-0044	SMITH POCOLA ENERGY PROJECT	OK	08/16/2001 ACT	AUXILIARY BOILERS, (2)	NATURAL GAS	48	MMBTU/H	Sulfur Dioxide (SO2)	USE OF PIPELINE NATURAL GAS W/SULFUR CONTENT 2 GRAINS SULFUR/100 SCF	0.57	LB/H	0.2	LB/MMBTU		
OK-0044	SMITH POCOLA ENERGY PROJECT	OK	08/16/2001 ACT	TURBINES, COMBINED CYCLE, NATURAL GAS, (4)	NATURAL GAS	171.5	MW	Sulfur Dioxide (SO2)	USE OF PIPELINE NATURAL GAS, SULFUR CONTENT LESS THAN 2 GR/100 SCF OR 65 PPMW	13.84	LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
OK-0044	SMITH POCOLA ENERGY PROJECT	OK	08/16/2001 ACT	TURBINES, NATURAL GAS, (4)	NATURAL GAS	171.5	MW	Sulfur Dioxide (SO2)	USE OF PIPELINE NATURAL GAS, SULFUR CONTENT LESS THAN 2 GR/100SCF OR 65 PPMW	10.59	LB/H	0			
OK-0050	ONETA GENERATING STA	OK	01/21/2000 ACT	DUCT BURNERS (4)	NATURAL GAS	328	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL - NATURAL GAS	0.0013	LB/MMBTU	0.0013	LB/MMBTU		
OK-0050	ONETA GENERATING STA	OK	01/21/2000 ACT	COMBUSTION TURBINES, COMBINED CYCLE (4)	NATURAL GAS	170	MW	Sulfur Oxides (SOx)	USE OF LOW SULFUR NATURAL GAS	2.5	LB/H	0			
OK-0051	GREEN COUNTRY ENERGY PROJECT	OK	10/01/1999 ACT	TURBINES WITH DUCT BURNERS, COMBINED CYCLE, (3)	NATURAL GAS			Sulfur Dioxide (SO2)	USE OF NATURAL GAS	0 006	LB/MMBTU	0			
OK-0051	GREEN COUNTRY ENERGY PROJECT	OK	10/01/1999 ACT	AUXILIARY BOILER	NATURAL GAS			Sulfur Dioxide (SO2)	USE OF NATURAL GAS	0 006	LB/MMBTU	0.006	LB/MMBTU		
OK-0071	MCCLAIN ENERGY FACILITY	OK	10/25/2001 ACT	AUXILIARY BOILER	NATURAL GAS	22	MMBTU/H	Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS	0 001	LB/MMBTU	0.001	LB/MMBTU		
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	OK	03/21/2003 ACT	TURBINES, COMBINED CYCLE (2)	NATURAL GAS	1701	MMBTU/H	Sulfur Dioxide (SO2)	USE OF PIPELINE-QUALITY NATURAL GAS (VERY LOW SULFUR FUEL) MAXIMUM 0.8 % S BY WT.	0 006	LB/MMBTU	0			
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	OK	03/21/2003 ACT	BOILER, AUXILIARY	NATURAL GAS	33	MMBTU/H	Sulfur Dioxide (SO2)	BACT IS USE OF PIPE-LINE QUALITY NATURAL GAS	0.2	LB/H	0.006	LB/MMBTU	calculated	
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	OK	03/21/2003 ACT	IC ENGINE, BACKUP GENERATOR, DIESEL	DIESEL	749	BHP	Sulfur Dioxide (SO2)	USE OF LOW SULFUR DIESEL FUEL (< 0 05% S BY WT)	0.3	LB/H	0			
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	OK	03/21/2003 ACT	IC ENGINE, FIRE WATER PUMP	DIESEL	265	BHP	Sulfur Dioxide (SO2)	USE OF VERY LOW SULFUR DIESEL FUEL (<0.05% S BY WT)	0.5	LB/H	0			
OK-0128	MID AMERICAN STEEL ROLLING MILL	OK	09/08/2008 ACT	Continuous Caster	natural gas	0		Sulfur Dioxide (SO2)	natural gas fuel	0.01	LB/H	0			
OK-0128	MID AMERICAN STEEL ROLLING MILL	OK	09/08/2008 ACT	Emergency Generator	No. 2 diesel	1200	HP	Sulfur Dioxide (SO2)	500 hours per year, 0.05% sulfur diesel fuel	0.49	LB/H	0			
OK-0128	MID AMERICAN STEEL ROLLING MILL	OK	09/08/2008 ACT	Ladle pre-heater and refractory drying	natural gas	0		Sulfur Dioxide (SO2)	natural gas fuel	0.0006	LB/MMBTU	0			
OK-0128	MID AMERICAN STEEL ROLLING MILL	OK	09/08/2008 ACT	Electric Arc Furnaces	electric	50	tons per furnace	Sulfur Dioxide (SO2)	cleaned scrap	0.3	LB/T SCRAP	0			
OK-0128	MID AMERICAN STEEL ROLLING MILL	OK	09/08/2008 ACT	Ladle Metallurgy Furnace		0		Sulfur Dioxide (SO2)		0.05	LB/T	0			
OK-0129	CHOUTEAU POWER PLANT	OK	01/23/2009 ACT	COMBINED CYCLE COGENERATION >25MW	NATURAL GAS	1882	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL	1.06	LB/H	0			
OK-0129	CHOUTEAU POWER PLANT	OK	01/23/2009 ACT	AUXILIARY BOILER	NATURAL GAS	33.5	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.03	LB/H	0			
OK-0129	CHOUTEAU POWER PLANT	OK	01/23/2009 ACT	FUEL GAS HEATER (H2O BATH)		18.8	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.01	LB/H	0			
OK-0129	CHOUTEAU POWER PLANT	OK	01/23/2009 ACT	EMERGENCY DIESEL GENERATOR (2200 HP)	LOW SULFUR DIESEL	2200	HP	Sulfur Dioxide (SO2)	LOW SULFUR DIESEL 0.05%S	0.89	LB/H	0			
OK-0129	CHOUTEAU POWER PLANT	OK	01/23/2009 ACT	EMERGENCY FIRE PUMP (267-HP DIESEL)	LOW SULFUR DIESEL	267	HP	Sulfur Dioxide (SO2)	LOW SULFUR DIESEL	0.11	LB/H	0			
OK-0134	PRYOR PLANT CHEMICAL	OK	02/23/2009 ACT	Primary Reformer (EUID #101, EUG#1-NH3 Plant #4)	Natural Gas	700	T/D Ammonia Production	Sulfur Dioxide (SO2)	Natural Gas	0.2	LB/MMBTU	0			
OK-0134	PRYOR PLANT CHEMICAL	OK	02/23/2009 ACT	Nitric Acid Preheaters No. 1 (EU 401, EUG 4)	Natural Gas	20	MMBTUH	Sulfur Dioxide (SO2)	natural gas combustion	0.03	LB/H	0			
OK-0135	PRYOR PLANT CHEMICAL	OK	02/23/2009 ACT	PRIMARY REFORMER	NATURAL GAS	700	Tons per Day	Sulfur Dioxide (SO2)		1.35	LB/H	0			
OK-0135	PRYOR PLANT CHEMICAL	OK	02/23/2009 ACT	NITRIC ACID PREHEATERS #1, #3, AND #4	NATURAL GAS	20	MMBTU/H	Sulfur Dioxide (SO2)		0.03	LB/H	0			
OK-0135	PRYOR PLANT CHEMICAL	OK	02/23/2009 ACT	BOILERS #1 AND #2	NATURAL GAS	80	MMBTU/H	Sulfur Dioxide (SO2)		0.2	LB/H	0			
PR-0007	COGENERATION PLANT (AES-PRCP)	PR	10/29/2001 ACT	LIMESTONE DRYER	PROPANE	13	MMBTU/H	Sulfur Dioxide (SO2)	USING PROPANE AND LOW SULFUR DISTILLATE OIL AND DIRECT CONTACT WITH LIMESTONE	0.26	LB/H	0 02	LB/MMBTU		
PR-0007	COGENERATION PLANT (AES-PRCP)	PR	10/29/2001 ACT	2 COAL-FIRED CIRCULATING FLUIDIZED BED BOILERS	BITUMINOUS COAL	454	MW (NET)	Sulfur Dioxide (SO2)	LOW-SULFUR COAL (MAX 1% S) AND DISTILLATE OIL (MAX 0.05% S)AND A LIMESTONE INJECTION SYSTEM AND CIRCULATING DRY SCRUBBER	9	PPMVD @ 7% O2	0.022	LB/MMBTU		
PR-0007	COGENERATION PLANT (AES-PRCP)	PR	10/29/2001 ACT	FIRE PUMP- DIESEL	DISTILLATE OIL			Sulfur Dioxide (SO2)	LIMITED OPERATION- LIMITED S IN FUEL	0.13	LB/H	0			
PR-0007	COGENERATION PLANT (AES-PRCP)	PR	10/29/2001 ACT	DIESEL GENERATOR, EMERGENCY EQUIPMENT	DISTILLATE OIL*			Sulfur Dioxide (SO2)	LIMITED OPERATION- LIMITED S IN FUEL	0.29	LB/H	0			
PR-0007	COGENERATION PLANT (AES-PRCP)	PR	10/29/2001 ACT	EMERGENCY BOILER FEED PUMP- DIESEL ENGINE	DISTILLATE OIL*			Sulfur Dioxide (SO2)	LIMITED OPERATION AND LIMITED FUEL SULFUR CONTENT	0.82	LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
SC-0061	COLUMBIA ENERGY LLC	SC	04/09/2001 ACT	TURBINES, COMBINED CYCLE, NATURAL GAS (2)	NATURAL GAS	170	MW (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	4.9	LB/H	0			
SC-0061	COLUMBIA ENERGY LLC	SC	04/09/2001 ACT	BOILERS, NATURAL GAS (2)	NATURAL GAS	350	MMBTU/H (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	0.63	LB/H	0.0018	LB/MMBTU		
SC-0061	COLUMBIA ENERGY LLC	SC	04/09/2001 ACT	BOILERS, FUEL OIL (2)	NO. 2 FUEL OIL	350	MMBTU/H	Sulfur Dioxide (SO2)	COMBUSTION OF LOW SULFUR FUELS	21	LB/H	0 06	LB/MMBTU		
SC-0061	COLUMBIA ENERGY LLC	SC	04/09/2001 ACT	HOT WATER HEATERS (2)	NATURAL GAS	11	MMBTU/H	Sulfur Dioxide (SO2)	CLEAN FUEL	3.5	LB/MMBTU	3.5	LB/MMBTU		
SC-0061	COLUMBIA ENERGY LLC	SC	04/09/2001 ACT	TURBINES, COMBINED CYCLE, DISTILLATE FUEL OIL (2)	DISTILLATE FUEL OIL	170	MW (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	99	LB/H	0			
SC-0065	BROAD RIVER INVESTORS - GAFFNEY	SC	12/21/2000 ACT	COMBUSTION TURBINES, NATURAL GAS (2)	NATURAL GAS	193	MW (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	1.1	LB/H	0			SO2 IS NOT SIGNIFICANT UNDER PSD-BACT, BUT A STATE BACT ANALYSIS WAS PERFORMED (SC DHEC 61-62 5, STANDARD 7)
SC-0065	BROAD RIVER INVESTORS - GAFFNEY	SC	12/21/2000 ACT	HOT WATER HEATERS, NAT. GAS (2)	NATURAL GAS	11	MMBTU/H (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.0065	LB/H	0			STATE BACT PERFORMED
SC-0112	NUCOR STEEL - BERKELEY	SC	05/05/2008 ACT	MELT SHOP		4380000	T/YR	Sulfur Dioxide (SO2)	SCRAP MANAGEMENT PROGRAM, GOOD OPERATING PRACTICES	0.2	LB/T	0			
SC-0112	NUCOR STEEL - BERKELEY	SC	05/05/2008 ACT	VACUUM TANK DEGASSER		0		Sulfur Dioxide (SO2)	USE OF NATURAL GAS COMBUSTION WITH GOOD COMBUSTION PRACTICES PER MANUFACTURER'S GUIDANCE	6.6	T/YR	0			
SC-0112	NUCOR STEEL - BERKELEY	SC	05/05/2008 ACT	VACUUM DEGASSER BOILER	NATURAL GAS	50 21	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION WITH GOOD COMBUSTION PRACTICES PER MANUFACTURER'S GUIDANCE	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
SC-0112	NUCOR STEEL - BERKELEY	SC	05/05/2008 ACT	TUNNEL FURNACE BURNERS	NATURAL GAS	58	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION WITH GOOD COMBUSTION PRACTICES PER MANUFACTURER'S GUIDANCE	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
SC-0112	NUCOR STEEL - BERKELEY	SC	05/05/2008 ACT	COIL CUTTING		0		Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION WITH GOOD COMBUSTION PRACTICES PER MANUFACTURER'S GUIDANCE	0.0006	LB/MMBTU	0			
SC-0113	PYRAMAX CERAMICS, LLC	SC	02/08/2012 ACT	PELLETIZER	NATURAL GAS	75	MMBTU/H	Sulfur Dioxide (SO2)	USE OF NATURAL GAS/PROPANE TO MINIMIZE COMBUSTION RELATED SO2.	0		0			MONITOR AND RECORD THE AMOUNT AND TYPE OF FUEL USED.
SC-0113	PYRAMAX CERAMICS, LLC	SC	02/08/2012 ACT	CALCINING/SINTERING KILN	NATURAL GAS	56.8	MMBTU/H	Sulfur Dioxide (SO2)	CATALYTIC BAGHOUSE. FUEL RESTRICTED TO NATURAL GAS AND PROPANE.	11.64	LB/H	0			MONITOR TYPE AND AMOUNT OF FUEL USAGE. CONTINUOUSLY MONITOR SORBENT INJECTION RATE. SAMPLE AND RECORD SULFUR CONTENT OF CLAY WEEKLY. SOURCE TESTING EVERY TWO YEARS.
SC-0113	PYRAMAX CERAMICS, LLC	SC	02/08/2012 ACT	BOILERS	NATURAL GAS	5	MMBTU/H	Sulfur Dioxide (SO2)	COMBUSTION OF NATURAL GAS AND PROPANE.	0		0			MONITOR AND RECORD TYPE AND QUANTITY OF FUEL USED.
SC-0113	PYRAMAX CERAMICS, LLC	SC	02/08/2012 ACT	EMERGENCY ENGINE 1 THRU 8	DIESEL	29	HP	Sulfur Dioxide (SO2)	LOW SULFUR DIESEL. MAXIMUM OF 100 HOURS PER YEAR RUNNING TIME FOR MAINTENANCE AND TESTING.	0		0			DIESEL FUEL SULFUR CONTENT SHALL BE < 0.0015 PERCENT. REPORTS OF FUEL SULFUR CONTENT SHALL BE MAINTAINED.
SC-0113	PYRAMAX CERAMICS, LLC	SC	02/08/2012 ACT	FIRE PUMP	DIESEL	500	HP	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL DIESEL, SULFUR CONTENT LESS THAN 0 0015 PERCENT. OPERATING HOURS LESS THAN 100 HOURS PER YEAR FOR MAINTENACE AND TESTING.	0		0			SULFUR CONTENT OF DIESEL FUEL TO BE LESS THAT 0.0015 PERCENT. SUPPLIER CERTIFICATION OF FUEL SULFUR CONTENT SHALL BE MAINTAINED.
SC-0113	PYRAMAX CERAMICS, LLC	SC	02/08/2012 ACT	EMERGENCY GENERATORS 1 THRU 8	DIESEL	757	HP	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL DIESEL, SULFUR CONTENT LESS THAN 0 0015 PERCENT. OPERATING HOURS LESS THAN 100 HOURS PER YEAR FOR MAINTENACE AND TESTING.	0		0			SULFUR CONTENT OF DIESEL FUEL TO BE LESS THAT 0.0015 PERCENT. SUPPLIER CERTIFICATION OF FUEL SULFUR CONTENT SHALL BE MAINTAINED.
SC-0114	GP ALLENDALE LP	SC	11/25/2008 ACT	PROPANE VAPORIZERS (ID15)	PROPANE	5	MMBTU/H	Sulfur Dioxide (SO2)	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.15	LB/H	0			
SC-0114	GP ALLENDALE LP	SC	11/25/2008 ACT	FIRE WATER DIESEL PUMP	DIESEL	525	HP	Sulfur Dioxide (SO2)	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.39	LB/H	0			ANNUAL EMISSIONS FROM THE DIESEL FIRE PUMP ARE BASED ON AN OPERATIONAL LIMIT OF 500 HR/YR.
SC-0114	GP ALLENDALE LP	SC	11/25/2008 ACT	DIESEL EMERGENCY GENERATOR	DIESEL	1400	HP	Sulfur Dioxide (SO2)		5.4	LB/H	0			
SC-0114	GP ALLENDALE LP	SC	11/25/2008 ACT	NATURAL GAS SPACE HEATERS - 14 UNITS (ID 18)	NATURAL GAS	20 89	MMBTU/H	Sulfur Dioxide (SO2)		0.01	LB/H	0			
SC-0114	GP ALLENDALE LP	SC	11/25/2008 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #1	WOOD	334	MMBTU/H	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	0			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8‘‘ BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8‘‘ BASIS/YR.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas < 100 million BTU/hr															
RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
SC-0114	GP ALLENDALE LP	SC	11/25/2008 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #2	WOOD	334	MMBTU/H	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	0			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8‘‘ BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8‘‘ BASIS/YR
SC-0114	GP ALLENDALE LP	SC	11/25/2008 ACT	197 MILLION BTU/HR WOOD FIRED FURNACE	WOOD	197	MMBTU/H	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD COMBUSTION PRACTICES.	28.14	LB/H	0			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8‘‘ BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8‘‘ BASIS/YR.
SC-0114	GP ALLENDALE LP	SC	11/25/2008 ACT	75 MILLION BTU/HR BACKUP THERMAL OIL HEATER	NATURAL GAS	75	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES WILL BE USED AS CONTROL FOR SO2 EMISSIONS.	0.04	LB/H	0			
SC-0114	GP ALLENDALE LP	SC	11/25/2008 ACT	ROTARY FLAKE DRYER #1		95000	LB/H OVEN DRY	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES	28.14	LB/H	0			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8‘‘ BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8‘‘ BASIS/YR.
SC-0114	GP ALLENDALE LP	SC	11/25/2008 ACT	ROTARY FLAKE DRYER #2		95000	LB/H OVEN DRY	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES	28.14	LB/H	0			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8‘‘ BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8‘‘ BASIS/YR.
SC-0114	GP ALLENDALE LP	SC	11/25/2008 ACT	ROTARY FINES DRYER		75000	LB/H OVEN DRY	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	0			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8‘‘ BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8‘‘ BASIS/YR.
SC-0114	GP ALLENDALE LP	SC	11/25/2008 ACT	MULTI-OPENING PRESS		1200000	MSF/YR 3/8",Sulfur Dioxide (SO2)"	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	0			APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8‘‘ BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8‘&lsq	

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
SC-0115	GP CLARENDON LP	SC	02/10/2009 ACT	334 MILLION BTU/HR WOOD FIRED FURNACE #2	WOOD	334	MMBTU/H	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	0			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8‘‘ BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8‘‘ BASIS/YR.
SC-0115	GP CLARENDON LP	SC	02/10/2009 ACT	197 MILLION BTU/HR WOOD FIRED FURNACE	WOOD	197	MMBTU/H	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD COMBUSTION PRACTICES.	28.14	LB/H	0			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8‘‘ BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8‘‘ BASIS/YR.
SC-0115	GP CLARENDON LP	SC	02/10/2009 ACT	75 MILLION BTU/HR BACKUP THERMAL OIL HEATER	NATURAL GAS	75	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES WILL BE USED AS CONTROL FOR SO2 EMISSIONS.	0.04	LB/H	0			
SC-0115	GP CLARENDON LP	SC	02/10/2009 ACT	ROTARY FLAKE DRYER #1		95000	OVEN DRY/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES WILL BE USED AS CONTROL FOR SO2 EMISSIONS.	28.14	LB/H	0			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8‘‘ BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8‘‘ BASIS/YR.
SC-0115	GP CLARENDON LP	SC	02/10/2009 ACT	ROTARY FLAKE DRYER #2		95000	LB/H OVEN DRY	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	0			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8‘‘ BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8‘‘ BASIS/YR.
SC-0115	GP CLARENDON LP	SC	02/10/2009 ACT	ROTARY FINES DRYER		75000	LB/H OVEN DRY	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	0			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8‘‘ BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8‘‘ BASIS/YR.
SC-0115	GP CLARENDON LP	SC	02/10/2009 ACT	MULTI-OPENING PRESS		1200000	MSF 3/8/YR"	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	0			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8‘‘ BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8‘‘ BASIS/YR.
SC-0115	GP CLARENDON LP	SC	02/10/2009 ACT	PROPANE VAPORIZERS (ID 14)	PROPANE	5	MMBTU/H	Sulfur Dioxide (SO2)	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.15	LB/H	0			THE TWO VAPORIZERS ARE LIMITED TO 16,000 MM BTU/YR, COMBINED.
SC-0115	GP CLARENDON LP	SC	02/10/2009 ACT	FIRE WATER DIESEL PUMP	DIESEL	525	HP	Sulfur Dioxide (SO2)	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	0.39	LB/H	0			ANNUAL EMISSIONS FROM THE DIESEL FIRE PUMP ARE BASED ON AN OPERATIONAL LIMIT OF 500 HR/YR.
SC-0115	GP CLARENDON LP	SC	02/10/2009 ACT	DIESEL EMERGENCY GENERATOR	DIESEL	1400	HP	Sulfur Dioxide (SO2)	TUNE-UPS AND INSPECTIONS WILL BE PERFORMED AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	5.4	LB/H	0			ANNUAL EMISSIONS FROM THE DIESEL EMERGENCY GENERATOR ARE BASED ON AN OPERATIONAL LIMIT OF 500 HR/YR.
SC-0115	GP CLARENDON LP	SC	02/10/2009 ACT	NATURAL GAS SPACE HEATERS - 14 UNITS (ID 17)	NATURAL GAS	20 89	MMBTU/H	Sulfur Dioxide (SO2)		0.01	LB/H	0			
SC-0115	GP CLARENDON LP	SC	02/10/2009 ACT	334 MILLION BTU/HR WOOD FIRED FURANCE #1	WOOD	334	MMBTU/H	Sulfur Dioxide (SO2)	SO2 EMISSIONS CONTROLLED THROUGH GOOD OPERATING PRACTICES.	28.14	LB/H	0			THESE LIMITS APPLY TO THE ENERGY/DRYER SYSTEM AND PRESS BECAUSE THESE SOURCES VENT TO A COMMON STACK. THE SHORT TERM (LB/HR) EMISSION LIMIT IS BASED ON A SHORT-TERM MAXIMUM OPERATING RATE OF 175 MSF 3/8‘‘ BASIS/HR. THE ANNUAL EMISSION LIMIT (TPY) IS BASED ON A LIMITED ANNUAL PRODUCTION RATE OF 1,200,000 MSF 3/8‘‘ BASIS/YR.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0274	SOLAR GAS TURBINE COGEN.	TX	04/03/2000 ACT	COGENERATION TURBINE WITH DUCT BURNER	NATURAL GAS	4.45	MW (CTG)	Sulfur Dioxide (SO2)	FUEL SPECIFICATIONS OF NO MORE THAN 2 5 GRAINS TOTAL SULFUR PER 100 DRY STANDARD CUBIC FEET ON A SHORT-TERM BASIS AND 0 5 GRAIN TOTAL SULFUR PER 100 DSCF ON A ROLLING 12-MONTH AVERAGE BASIS.	1.87	LB/H	0			
TX-0274	SOLAR GAS TURBINE COGEN.	TX	04/03/2000 ACT	AUXILIARY BOILER	NATURAL GAS	54 01	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SPECIFICATIONS OF NO MORE THAN 2 5 GRAINS TOTAL SULFUR PER 100 DRY STANDARD CUBIC FEET ON A SHORT-TERM BASIS AND 0 5 GRAIN TOTAL SULFUR PER 100 DSCF ON A ROLLING 12-MONTH AVERAGE BASIS.	0.77	LB/H	0.014	LB/MMBTU	CONVERTED USING THROUGHPUT	
TX-0309	FORMOSA PLASTICS TEXAS	TX	02/10/2000 ACT	(2) STARTUP HEATERS, 70H101-1&-2		75	MMBTU/H, EA	Sulfur Dioxide (SO2)	NONE INDICATED	0.04	LB/H	0.0005	LB/MMBTU	CALCULATED FROM HOURLY E.L. AND THRUPUT	
TX-0309	FORMOSA PLASTICS TEXAS	TX	02/10/2000 ACT	PROCESS FUGITIVES, 70ANFUG				Sulfur Dioxide (SO2)	NONE INDICATED	0.46	LB/H	0			FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED AS A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0309	FORMOSA PLASTICS TEXAS	TX	02/10/2000 ACT	WASTE HEAT BOILER, 70Z401	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.26	LB/H	0			
TX-0309	FORMOSA PLASTICS TEXAS	TX	02/10/2000 ACT	PROCESS FLARE, 70Z522				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TRAIN 1- ETSH OR TBM PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TRAIN 1 - MESH PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES FOR LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TRAIN 2- MESH PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SULFUR TRUCK, S-3				Sulfur Dioxide (SO2)	NONE INDICATED	0.07	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TANK TRUCK LOADING/UNLOADING FUGITIVES				Sulfur, Total Reduced (TRS)	SEE POLLUTANT NOTES. FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.03	LB/H	0			ALL LOADING LINES SHALL BE INSPECTED VISUALLY FOR POSSIBLE LEAK SITES BEFORE THE START OF ANY LOADING OPERATIONS. DAMAGED HOSES SHALL BE REPAIRED OR REPLACED BEFORE ANY LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADING OPERATIONS, ALL LOADING LINES (EXCEPT FOR MMP) SHALL BE PURGED WITH INERT GAS TO THE FLARE BEFORE ANY CONNECTIONS BETWEEN THE LOADING RACKS AND LOADED VESSELS ARE BROKEN. MMP RAILCAR LOADING WILL USE CLOSED LOOP VAPOR BALANCE SYSTEMS CONNECTED TO THE MMP STORAGE TANK OR THE SULFOX-TO. UPON COMPLETION OF MMP LOADING OPERATIONS THE LOADING LINE WILL BE PURGED INTO THE RAILCAR OR THE MMP STORAGE TANK. WHEN UNHOOKING THE RAILCAR FROM THE LOADING LINE, AN ACETIC ACID OR EQUIVALENT WASH WILL BE DONE AFTER EACH MMP LOADING. THE WASH MATERIAL WILL BE NEUTRALIZED AND MANAGED IN THE ON-SITE WASTEWATER SYSTEM. THE WASH MATERIAL TANK WILL VENT TO THE SULFOX-TO.

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, SSM				Sulfur Dioxide (SO2)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18. SEE THE POLLUTANT NOTES.	2541.37	LB/H	0			TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW 5193 LB/H.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, SSM				Sulfur, Total Reduced (TRS)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18	24.27	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, TOTAL HOURLY AND ANNUAL				Sulfur Dioxide (SO2)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18. SEE POLLUTANT NOTES.	6207.34	LB/H	0			TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW 5193 LB/H.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, TOTAL HOURLY AND ANNUAL				Sulfur, Total Reduced (TRS)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18	65.62	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	HEAT TRANSFER FLUID HEATER, H202	NATURAL GAS	31	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.02	LB/H	0.0006	LB/MMBTU	CALCULATED, USING THROUGHPUT	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	(2) SULFUR/METHANE HEATERS				Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.01	LB/H	0		NOT AVAILABLE	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	HEAT TRANSFER FLUID HEATER, H2202	NATURAL GAS	31	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 0.5 GR S/100 DSCF.	0.02	LB/H	0.0006	LB/MMBTU	CALCULATED USING THROUGHPUT	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	INCINERATOR				Sulfur Dioxide (SO2)	NONE INDICATED	139	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SULFUR STORAGE TANK, S-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.86	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SULFUR PIT, S-2				Sulfur Dioxide (SO2)	NONE INDICATED	0.17	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SOUR WATER STRIPPERS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, SSM		134.5	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	1156.47	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, SSM		134.5	MMBTU/H	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, TOTAL HOURLY AND ANNUAL		134.5	MMBTU/H	Sulfur Dioxide (SO2)	THE FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	1157.44	LB/H	0			WASTE GAS AND ATOMIZED LIQUID STREAMS FROM THE SULFOX UNITS SHALL BE ROUTED TO THE SULFOX TO. THE SULFOX TO SHALL DESTROY THE VOC STREAMS SENT TO IT AT A MINIMUM OF 99.9% OR AT A VOC OUTLET CONCENTRATION OF 10 PPMV.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, TOTAL HOURLY AND ANNUAL		134.5	MMBTU/H	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, STEADY STATE OPERATION				Sulfur Dioxide (SO2)	FOLLOW SPECIFICATIONS OF 40 CFR 60.18. SEE POLLUTANT NOTES.	3665.97	LB/H	0			TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW 5193 LB/H.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, STEADY STATE OPERATION				Sulfur, Total Reduced (TRS)	FOLLOW REQUIREMENTS OF 40 CFR 60.18	41.35	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	PRODUCT RECOVERY TOWER FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	RAILCAR LOADING/UNLOADING FUGITIVES				Sulfur, Total Reduced (TRS)	SEE POLLUTANT NOTES.	0.03	LB/H	0			ALL LOADING LINES SHALL BE INSPECTED VISUALLY FOR POSSIBLE LEAK SITES BEFORE THE START OF ANY LOADING OPERATIONS. DAMAGED HOSES SHALL BE REPAIRED OR REPLACED BEFORE ANY LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADING OPERATIONS, ALL LOADING LINES (EXCEPT FOR MMP) SHALL BE PURGED WITH INERT GAS TO THE FLARE BEFORE ANY CONNECTIONS BETWEEN THE LOADING RACKS AND LOADED VESSELS ARE BROKEN. MMP RAILCAR LOADING WILL USE CLOSED LOOP VAPOR BALANCE SYSTEMS CONNECTED TO THE MMP STORAGE TANK OR THE SULFOX-TO. UPON COMPLETION OF MMP LOADING OPERATIONS THE LOADING LINE WILL BE PURGED INTO THE RAILCAR OR THE MMP STORAGE TANK. WHEN UNHOOKING THE RAILCAR FROM THE LOADING LINE, AN ACETIC ACID OR EQUIVALENT WASH WILL BE DONE AFTER EACH MMP LOADING. THE WASH MATERIAL WILL BE NEUTRALIZED AND MANAGED IN THE ON-SITE WASTEWATER SYSTEM. THE WASH MATERIAL TANK WILL VENT TO THE SULFOX-TO.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	DIMETHYL DISULFIDE AREA PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.06	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	(2) STEAM BOILERS, X-426A AND X-426B	NATURAL GAS	15.8	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.01	LB/H	0.0006	LB/MMBTU	EACH, CALCULATED USING THROUGHPUT	

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	RUNDOWN TANK FUGITIVES				Sulfur, Total Reduced (TRS)	MMP DAY STORAGE TANKS WILL VENT TO THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULF0X-TO. FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.11	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	STORAGE TANKS FUGITIVES				Sulfur, Total Reduced (TRS)	MMP DAY STORAGE TANKS WILL VENT TO THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULF0X-TO. FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.15	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	DIMETHYL SULFIDE AREA PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	H2S PLANT PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, STEADY STATE SERVICE		134.5	MMBTU/H	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, STEADY STATE SERVICE		134.5	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS COMBUSTED IN EACH COMBUSTION EMISSION POINT NUMBER SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	4.21	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FOREHEARTH MONITOR, FURNACE NO 5				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	CURING OVEN NO 1 & 2 FURNACE NO 5				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(5) HOT AIR DRYERS, FURNACE NO 5				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	HOT AIR DRYER NO 6, FURNACE 5				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(6) HOT AIR DRYER NO 31, 32, 33, 34, 35, 36				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	RTP DRYER NO 15				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	MAT LINE (DRYERS & CLEANER)				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	HOT AIR DRYER NO 45				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	BOILER NO. 2	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.04	LB/H	0		NOT AVAILABLE	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(2) EMERGENCY GENERATORS NO. 1 & 2	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED	5.51	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	PROPANE FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.49	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	PROPANE EVAPORATOR NO. 1				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(3) PROPANE EVAPORATORS NO 2, 3, 4				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(2) FURNACE FOREHEARTHS NO 1 & 2				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(2) RTP DRYERS NO 12 & 13				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(3) RTP DRYERS NO 16, 17, 18				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	BOILER NO 3	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.03	LB/H	0		NOT AVAILABLE	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	DIESEL GENERATOR	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED	0.93	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FURNACE NO 5	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	11.4	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FURNACE FOREHEARTH NO 3				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FURNACE NO 4 FOREHEARTH & RTP CHOPPER				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	HOT AIR DRYER NO 98				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(2) RTP DRYERS 10 & 11				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	POST CURING OVEN NO 1				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(2) POST CURING OVENS NO 2 & 3				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FURNACE NO 3	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	6.66	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FURNACE NO. 1	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	20.31	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FURNACE NO 2	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	20.31	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FURNACE NO 4	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	9.03	LB/H	0			
TX-0364	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	(2) INGERSOLL-RAND ENGINES, #IR-SVG-8, EPN4&5	NAT GAS	440	HP	Sulfur Dioxide (SO2)	NONE INDICATED	0.7	LB/H	0			
TX-0364	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	HOT OIL HEATER, EPN6	NAT GAS	12	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0.0008	LB/MMBTU	SEE NOTE	STANDARDIZED EMISSION LIMIT CALCULATED FROM HEAT RATING AND HOURLY EMISSION LIMIT.
TX-0364	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	(2) INGERSOLL-RAND ENGINES, #IR-SVG-8, EPN10A&B	NAT GAS	1330	HP	Sulfur Dioxide (SO2)	NONE INDICATED	0.33	LB/H	0			
TX-0364	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	GLYCOL REBOILER, EPN11	NAT GAS	2.5	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.02	LB/H	0.008	LB/MMBTU	SEE NOTE	STANDARDIZED EMISSION LIMIT CALCULATED FROM HEAT RATING AND HOURLY EMISSION LIMIT.
TX-0364	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	(3) COOPER-BESSEMER ENGINES, #GMVH-12C2, EPN21-23	NAT GAS	3105	HP	Sulfur Dioxide (SO2)	NONE INDICATED	0.26	LB/H	0			
TX-0364	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	HOT OIL HEATER, EPN26	NAT GAS	32.5	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.02	LB/H	0.0006	LB/MMBTU	SEE NOTE	STANDARDIZED EMISSION LIMIT CALCULATED FROM HEAT RATING AND HOURLY EMISSION LIMIT.
TX-0364	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	(2) FLARES, EPN 9 & 29				Sulfur Dioxide (SO2)	NONE INDICATED	50.48	LB/H	0			
TX-0364	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	HP TEG FIREBOX, EPN30	NAT GAS	3	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0.003	LB/MMBTU	CALCULATED, SEE NOTE	STANDARDIZED EMISSION LIMIT CALCULATED FROM HEAT RATING AND HOURLY EMISSION LIMIT.
TX-0364	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	COOPER-BESSEMER ENGINE, #GMVH-12, EPN1	NAT GAS	2400	HP	Sulfur Dioxide (SO2)	USE PIPELINE QUALITY SWEET NATURAL GAS	0.36	LB/H	0			
TX-0364	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	(2) CLARK ENGINE, #TLAB-6, EPN2&3	NAT GAS	2000	HP EACH	Sulfur Dioxide (SO2)	NONE INDICATED	0.31	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	PACKAGE BOILER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE	
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	STANDBY INCINERATOR				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	PACKAGE BOILER BO-4	NAT GAS	60	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.95	LB/H	0 02	LB/MMBTU	CALCULATED USING THROUGHPUT	
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	REGENERATIVE GAS HEATER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE	
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	MONUMENT NO. 2 FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	WASTE HEAT BOILER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE	
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	TRAIN NO. 8 FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	ALKYL FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0388	SAND HILL ENERGY CENTER	TX	02/12/2002 ACT	GAS TURBINES, SIMPLE CYCLE (4)	NATURAL GAS	48	MW (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR (0.23 GRAINS S/100 DSCF)PIPELINE QUALITY NATURAL GAS.	0.3	LB/H	0			
TX-0388	SAND HILL ENERGY CENTER	TX	02/12/2002 ACT	COMBINED CYCLE GAS TURBINE	NATURAL GAS	164	MW	Sulfur Dioxide (SO2)	LOW SULFUR FUEL (0.23 GR/DSCF)	1.6	LB/H	0			
TX-0388	SAND HILL ENERGY CENTER	TX	02/12/2002 ACT	INLET AIR HEATERS (3)				Sulfur Dioxide (SO2)	FUEL RESTRICTED TO 0.23 GR S/100 DSCF.	0 003	LB/H	0			
TX-0389	BAYTOWN CARBON BLACK PLANT	TX	12/31/2002 ACT	CARBON BLACK PROCESS CAPS	NATURAL GAS			Sulfur Dioxide (SO2)	SCRUBBER, LOW SULFUR (<2.5%)FEEDSTOCK OIL	859.3	LB/H	0			
TX-0389	BAYTOWN CARBON BLACK PLANT	TX	12/31/2002 ACT	BACK-UP BOILER	NATURAL GAS	13.4	MMBUT/H	Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0392	LUCITE BEAUMONT	TX	12/09/2002 ACT	SULFURIC ACID PLANT				Sulfur Dioxide (SO2)		130	LB/H	4	LB/T H2SO4		

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0392	LUCITE BEAUMONT	TX	12/09/2002 ACT	NO.1 PRE-HEATER	NATURAL GAS			Sulfur Dioxide (SO2)		0.1	LB/H	0			
TX-0392	LUCITE BEAUMONT	TX	12/09/2002 ACT	NO. 2 PRE-HEATER	NATURAL GAS			Sulfur Dioxide (SO2)		0.1	LB/H	0			
TX-0408	INDIAN ROCK GATHERING COMPANY LP	TX	11/22/2002 ACT	AUXILIARY BOILER, (2)	NATURAL GAS	6	MMBTU/H	Sulfur Dioxide (SO2)		0.01	LB/H	0.0017	LB/MMBTU		UNCONTROLLED BECAUSE BOILER IS LESS THAN 40 MMBTU/H.
TX-0408	INDIAN ROCK GATHERING COMPANY LP	TX	11/22/2002 ACT	SULFUR RECOVERY UNIT		20	LT/D	Sulfur Dioxide (SO2)	THERMAL OXIDIZER	61.86	LB/H	0			
TX-0408	INDIAN ROCK GATHERING COMPANY LP	TX	11/22/2002 ACT	IC ENGINE COMPRESSOR, (5)	NATURAL GAS	800	HP	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE	0.01	LB/H	0			
TX-0458	JACK COUNTY POWER PLANT	TX	07/22/2003 ACT	COMBUSTION TURBINE WITH 550 MMBTU/HR DUCT BURNER	NATURAL GAS			Sulfur Dioxide (SO2)	BURN LOW SULFUR NATURAL GAS	14.5	LB/H	0			
TX-0458	JACK COUNTY POWER PLANT	TX	07/22/2003 ACT	AUXILIARY BOILER	NATURAL GAS	36	mmbtu/h	Sulfur Dioxide (SO2)		0.3	LB/H	0			
TX-0458	JACK COUNTY POWER PLANT	TX	07/22/2003 ACT	FIRE WATER PUMP ENGINE				Sulfur Dioxide (SO2)		0.5	LB/H	0			
TX-0458	JACK COUNTY POWER PLANT	TX	07/22/2003 ACT	EMERGENCY GENERATOR (6)				Sulfur Dioxide (SO2)		1.4	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	TURBINE EXHAUST DUCT BURNER (3)	NATURAL GAS			Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	POWER STEAM BOILER	NATURAL GAS	93	MMBTU/H	Sulfur Dioxide (SO2)		0.05	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	TREATED GAS COMPRESSOR ENGINE STACK WITH CATALYTIC CONVERTER WAUKESHA L-7042GSI		875	HP	Sulfur Dioxide (SO2)		0.46	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	TAIL GAS INCINERATOR STACK				Sulfur Dioxide (SO2)		350	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	BOTTOM HEATERS (2)		15	MMBTU/H	Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	ALLISON 501KB GAS TURBINE GENERATOR	NATURAL GAS			Sulfur Dioxide (SO2)		0.67	LB/H	0			
VA-0243	STANLEY FURNITURE	VA	12/01/2002 EST	BOILER, NAT GAS & OIL	NATURAL GAS	26.5	MMBTU/H	Sulfur Dioxide (SO2)	EMISSION LIMITS IN T/YR ONLY	16	T/YR	0		NOT AVAILABLE	
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS, DUCT BURNER	NATURAL GAS	1937	MMBTU/H	Sulfur Dioxide (SO2)		2.08	LB/H	0			
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	TURBINE, COMBINED CYCLE , FUEL OIL	DISTILLATE FUEL OIL	2080	MMBTU/H	Sulfur Dioxide (SO2)		98.9	LB/H	0			
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	BOILER, TANGENTIALLY-FIRED, UNIT 4	NATURAL GAS	2350	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS AND GOOD COMBUSTION PRACTICES.	14	T/YR	0.0014	LB/MMBTU		
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	BOILER, AUXILIARY	NATURAL GAS	99	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL AND GOOD COMBUSTION PRACTICES.	0.1	LB/H	0.001	LB/MMBTU	EACH UNIT	
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	TURBINE, NATURAL GAS, NO DUCT BURNER FIRING	NATURAL GAS	1937	MMBTU/H	Sulfur Dioxide (SO2)		1.74	LB/H	0			
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	DUCT BURNERS	NATURAL GAS	385	MMBTU/H	Sulfur Dioxide (SO2)		0.2	LB/MMBTU	0.2	LB/MMBTU		
VA-0255	VA POWER - POSSUM POINT	VA	11/18/2002 ACT	BOILER, TANGENTIALLY-FIRED, UNIT 3	NATURAL GAS	1150	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL.	14	T/YR	0.0028	LB/MMBTU		
VA-0271	HARRISONBURG RESOURCE RECOVER FACILITY	VA	03/24/2003 ACT	MUNICIPAL WASTE COMBUSTION	SOLID WASTE	36500	T/YR	Sulfur Dioxide (SO2)	DRY FLUE GAS SCRUBBING SYSTEM USING A HYDRATED LIME SORBENT OR OTHER DEQ APPROVED SUITABLE SORBENT. A CONTINUOUS EMISSION MONITORING SYSTEM	5.5	LB/H	0		NOT AVAILABLE	1 of 2 units
VA-0271	HARRISONBURG RESOURCE RECOVER FACILITY	VA	03/24/2003 ACT	BOILER NO. 1	NATURAL GAS	43.2	MMBTU/H	Sulfur Dioxide (SO2)	CONTINUOUS EMISSION MONITORING SYSTEM AND GOOD COMBUSTION PRACTICES.	2.19	LB/H	0 05	LB/MMBTU		One of two units.
VA-0271	HARRISONBURG RESOURCE RECOVER FACILITY	VA	03/24/2003 ACT	BOILER NO.2	DISTILLATE FUEL OIL	43.2	MMBTU	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES AND CONTINUOUS EMISSION MONITORING SYSTEM.	2.19	LB/H	0		NOT AVAILABLE	One of two units
VA-0271	HARRISONBURG RESOURCE RECOVER FACILITY	VA	03/24/2003 ACT	BOILER NO. 3	NAT GAS OR DIS OIL	43.2	MMBTU	Sulfur Dioxide (SO2)	CONTINUOUS EMISSION MONITORING SYSTEM AND GOOD COMBUSTION PRACTICES.	4.76	T/YR	0		NOT AVAILABLE	Combined units on either fuel type
VA-0271	HARRISONBURG RESOURCE RECOVER FACILITY	VA	03/24/2003 ACT	TURBINE SHREDDER	DISTILLATE OIL	1 08	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES. LOW SULFER FUEL.	0.32	LB/H	0			
VA-0279	CINCAP - MARTINSVILLE	VA	01/08/2003 ACT	IC ENGINE, FIRE WATER PUMP	DIESEL	300	KW	Sulfur Dioxide (SO2)	FUEL SULFUR LIMIT: < 0.05% S BY WT	0		0			limit is fuel sulfur limit. No emission rate limit.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Natural Gas < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
VA-0279	CINCAP - MARTINSVILLE	VA	01/08/2003 ACT	TURBINE, SIMPLE CYCLE, NATURAL GAS (4)	NATURAL GAS	82	MW	Sulfur Dioxide (SO2)	FUEL SULFUR LIMIT: 0 8 GR/100 DSCF, ANNUAL AVG, AND 1.5 GR/100 DSCF ON HOURLY BASIS.	4	LB/H	0			
VA-0279	CINCAP - MARTINSVILLE	VA	01/08/2003 ACT	HEATER, PIPELINE WATER BATH, NATURAL GAS	NATURAL GAS	5	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR LIMIT: 0 8 GR/100 DSCF ANNUAL AVG., 1 5 GR/100 DSCF ON AN HOURLY BASIS	0		0			limit is fuel sulfur limit, no emission rate limit.
WA-0292	SATSOP COMBUSTION TURBINE PROJECT	WA	10/23/2001 ACT	(2) NAT GAS COMBINED CYCLE COMBUSTION TURBINES	NATURAL GAS	325	MW	Sulfur Dioxide (SO2)		3.3	LB/H	0			NATURAL GAS SULFUR IS HIGHER THAN NATIONAL AV. IF PLANT IS UNABLE TO COMPLY WITH LIMIT IT MAY HAVE TO INSTALL A NATURAL GAS OR FLUE GAS SULFUR REMOVAL PROCESS TO PROTECT VISIBILITY AND DEPOSITION AT OLYMPIC NATIONAL PARK. THE ORIGINAL PERMIT LIMITED SO2 EMISSIONS TO 0.11 PPM AND 1.3 LB/HR.
WA-0292	SATSOP COMBUSTION TURBINE PROJECT	WA	10/23/2001 ACT	AUXILIARY BOILER	NAT GAS	29.3	MMBTU/H	Sulfur Dioxide (SO2)		0.07	LB/H	0			THE ORIGINAL PERMIT LIMITED SO2 EMISSIONS TO 0.03 LB/HR AND 0.001 LB/MMBTU.
WI-0195	SENA NIAGARA MILL	WI	10/18/2002 ACT	PROCESS HEATER, PAPER MACHINE P51	NATURAL GAS	34.4	MMBTU/H	Sulfur Dioxide (SO2)	BACT IS USE OF NATURAL GAS	0		0			No emission rate limits, BACT is pollution prevention
WI-0226	WPS - WESTON PLANT	WI	08/27/2004 ACT	NATURAL GAS FIRED BOILER	NATURAL GAS	46.2	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL ONLY	0.05	LB/H	0			
WI-0227	PORT WASHINGTON GENERATING STATION	WI	10/13/2004 ACT	COMBINED CYCLE COMBUSTION TURBINES (4 W/ DUCT BURNER, HRSG)	NATURAL GAS	2096	MMBTU/H	Sulfur Dioxide (SO2)	PIPELINE QUALITY NATURAL GAS	1.48	LB/H	0			FOUR (4) COMBINED CYCLE COMBUSTION TURBINES (2096 MMBTU/HR EACH.)
WI-0227	PORT WASHINGTON GENERATING STATION	WI	10/13/2004 ACT	DIESEL ENGINE GENERATOR (P05 / S05)	DIESEL FUEL OIL	7.6	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR DIESEL FUEL OIL (0 05 WT% S)	0.38	LB/H	0			
WI-0227	PORT WASHINGTON GENERATING STATION	WI	10/13/2004 ACT	NATURAL GAS FIRED AUXILLIARY BOILER	NATURAL GAS	97.1	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL	0.06	LB/H	0.006	LB/MMBTU	CALCULATED	
WI-0227	PORT WASHINGTON GENERATING STATION	WI	10/13/2004 ACT	GAS HEATER (P06, S06)	NATURAL GAS	10	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS FUEL	0.02	LB/H	0.002	LB/MMBTU	CALCULATED	
WI-0228	WPS - WESTON PLANT	WI	10/19/2004 ACT	AUXILLIARY NAT. GAS FIRED BOILER (B25, S25)	NATURAL GAS	229.8	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS	0.0006	LB/MMBTU	0			
WI-0228	WPS - WESTON PLANT	WI	10/19/2004 ACT	DIESEL BOOSTER PUMP (B27, S27)	DIESEL FUEL OIL	265	HP	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMIT (0 003 WT. % S) GOOD COMBUSTION PRACTICES	0.54	LB/H	0			'ULTRA LOW SULFUR DIESEL FUEL'
WI-0228	WPS - WESTON PLANT	WI	10/19/2004 ACT	MAIN FIRE PUMP (DIESEL ENGINE)	DIESEL FUEL OIL	460	HP	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES, ULTRA LOW SULFUR (0.003 WT. % S) DIESEL FUEL OIL	0.94	LB/H	0			
WI-0228	WPS - WESTON PLANT	WI	10/19/2004 ACT	B63, S63; B64, S64 - NATURAL GAS STATION HEATER 1 AND 2	NATURAL GAS	0.75	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS	0.0004	LB/H	0		NOT AVAILABLE	(LIMIT IS FOR EACH UNIT)
WI-0228	WPS - WESTON PLANT	WI	10/19/2004 ACT	SUPER CRITICAL PULVERIZED COAL ELECTRIC STEAM BOILER (S04, P04)	PRB COAL	5173 07	MMBTU/H	Sulfur Dioxide (SO2)	DRY FGD, LIMIT ON EMISSIONS ENTERING CONTROL SYSTEM: 1.23 LBS/MMBTU 30 DAY AVG.	0.1	LB/MMBTU	0			POLLUTANT LIMITS INCLUDE STARTUP / SHUTDOWN AND ATOMIZER CHANGEOUT. PERMITTEE MAY ONLY USE ACTUAL HOURS OF OPERATION WHEN DETERMINING TIME AVERAGED EMISSIONS. WHEN CONDUCTING MAINTENANCE ON CONTROL SYSTEM (ROUTINE ATOMIZER CHANGEOUT): 3491 8 POUNDS PER HOUR ON A 3-HOUR AVERAGE AND 1508.9 POUNDS PER HOUR ON A 24-HOUR AVERAGE. CONTROLLED EMISSIONS: SULFUR DIOXIDE EMISSIONS SHALL BE LIMITED TO 621 POUNDS PER HOUR AVERAGED OVER ANY CONSECUTIVE 3-HOUR PERIOD AND SULFUR DIOXIDE EMISSIONS SHALL BE LIMITED TO 589 POUNDS PER HOUR AVERAGED OVER ANY CONSECUTIVE 24-HOUR PERIOD

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	DUCT BURNER FOR STEAM GENERATION, E-1410	NATURAL GAS*	36.5	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LIQUEFIED PETROLEUM GAS, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		500	PPM @ 15% O2	ASSUMED @ 15% O2	ESTIMATED EMISSIONS ARE 10.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	CRUDE HEATER, H101B	NATURAL GAS*	165	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S. GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED FOR SO2 AND H2S TOGETHER. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2. LIMITS ARE PROVIDED BASED ON FUEL CONTENT (SEE POLLUTION PREVENTION DESCRIPTION). ESTIMATED EMISSIONS ARE 21.7 T/YR, BUT THIS IS NOT A LIMIT. ADDITIONAL LIMIT IS A PRORATED CONCENTRATION OF THE FOLLOWING: 230 MG H2S/DSCF FOR EQUIPMENT FIRED ON REFINERY GAS, AND 500 PPM SO2 FOR EQUIPMENT NOT FIRED ON REFINERY GAS.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	POWERFORMER PREHEATER, H201	NATURAL GAS*	31.8	MMBTU/H	Sulfur Dioxide (SO2)	SOURCE WAS INSTALLED PRIOR TO 1975 SO IT IS NOT SUBJECT TO BACT-PSD.	0		0			ESTIMATED EMISSIONS ARE 4 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	POWERFORMER PREHEATER, H202	NATURAL GAS*	51	MMBTU/H	Sulfur Dioxide (SO2)	SOURCE IS NOT SUBJECT TO FUEL LIMITATIONS UNDER BACT-PSD BECAUSE IT WAS INSTALLED PRIOR TO 1975.	0		0			ESTIMATED EMISSIONS ARE 6.7 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	POWERFORMER PREHEATER, H203	NATURAL GAS*	27.9	MMBTU/H	Sulfur Dioxide (SO2)	SOURCE WAS INSTALLED PRIOR TO 1975 AND IS THEREFORE NOT SUBJECT TO PSD.	0		0			ESTIMATED EMISSIONS ARE 3.7 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	POWERFORMER REHEATER, H204	NATURAL GAS*	53.8	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR CONTENT FUEL LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR, NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR H2S AND SO2. ESTIMATED SO2 EMISSIONS ARE 7.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. ONLY EMISSION LIMITS PROVIDED ARE A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER THREE HOURS, AND 500 PPM SO2 AVERAGED OVER THREE HOURS. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	HYDROCRACKER RECYCLE GAS HEATER, H401	NATURAL GAS*	38.9	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR LIMITS AS FOLLOWS IS CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS COMBINED FOR SO2 AND H2S. ONLY EMISSION LIMITS PROVIDED ARE A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER THREE HOURS, AND 500 PPM SO2 AVERAGED OVER THREE HOURS. ESTIMATED SO2 EMISSIONS ARE 5.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	HYDROCRACKER RECYCLE GAS HEATER, H402	NATURAL GAS*	38	MMBTU/H	Sulfur Dioxide (SO2)	THE FOLLOWING FUEL SULFUR CONTENT LIMITS ARE CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS COMBINED FOR SO2 AND H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF THE FOLLOWING: 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2. ESTIMATED EMISSIONS OF SO2 ARE 5 0 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	SOL. CEN. GAS TURBINE (NG) & DUCT BURNER, GT/E1410	NATURAL GAS*	50.9	MMBTU/H	Sulfur Oxides (SOx)	THE FOLLOWING FUEL SULFUR CONTENT LIMITS ARE CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			ESTIMATED EMISSIONS ARE 10.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	SOL. CEN. GAS TURBINE (NG) & DUCT BURNER, GT/E1400	NATURAL GAS*	50.9	MMBTU/H	Sulfur Oxides (SOx)	THE FOLLOWING FUEL SULFUR CONTENT LIMITS ARE CONSIDERED BACT: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			ESTIMATED EMISSIONS ARE 10.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS SUBJECT TO NSPS FOR SO2.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	DUCT BURNER FOR STEAM GENERATION, E-1400	NATURAL GAS*	36.5	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		500	PPM @ 15% O2	ASSUMED 15% O2	ESTIMATED EMISSIONS WHEN BURNING LPG, NG, OR DIESEL, ARE 10.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	REFINERY FLARE, J 801	NATURAL GAS*	1	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUEFIED PETROLEUM GAS, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH FOR SO2 AND H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF THE FOLLOWING; 230 MB H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	ELECTRIC GENERATOR CAT 3412, EG704	DIESEL	4.8	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	STEWART-STEVENSON GENERATOR, EG801	DIESEL	6.1	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	NORTH CATERPILLAR, P605A	NATURAL GAS	5.6	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0.1 T/YR SO2, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	SOUTH CATERPILLAR, P605B	NATURAL GAS	830	HP	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	NORTH CUMMINS, P708A	DIESEL	290	HP	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	SOUTH CUMMINS, P708B	DIESEL	290	HP	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	UPPER TANK FARM CAT 3412DT, P708C	DIESEL	660	HP	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0 5 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	HOT OIL HEATER, H609	NATURAL GAS*	56	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED. SOURCE IS NOT SUBJECT TO BACT- PSD BECAUSE IT WAS INSTALLED PRIOR TO 1975.	0		0			ESTIMATED EMISSIONS ARE 7.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	HYDROGEN REFORMER FURNACE, H1001	NATURAL GAS*	152.3	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR SO2 AND H2S. EMISSIONS LIMITS ARE A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE 20 0 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	REACTION FURNACE BURNER, H1101	NATURAL GAS*	5.2	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER THREE HOURS AND 500 PPM SO2 AVERAGED OVER THREE HOURS. ESTIMATED SO2 EMISSIONS ARE 0.7 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	COOLING TOWER CAT, P719C	NATURAL GAS	1.1	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0 01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	SULFUR RECOVERY UNIT		19.3	LTPD	Sulfur Dioxide (SO2)	NONE INDICATED	0		0			ESTIMATED EMISSIONS ARE 14.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	TAIL GAS BURNER, H1105	NATURAL GAS*	2	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED SO2 EMISSIONS ARE 0 3 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	#4 REHEATER STARTUP BURNER, H1106	NATURAL GAS*	1.9	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	PRIP ABSORBER FEED FURNACE, H1201/1203	NATURAL GAS*	10.4	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR SO2 AND H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE 1.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	CRUDE HEATER, H101A	NATURAL GAS*	140	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED AS SOURCE WAS INSTALLED PRIOR TO 1975 AND IS NOT SUBJECT TO BACT-PSD.	0		0			SOURCE IS NOT SUBJECT TO PSD REQUIREMENTS BECAUSE IT WAS INSTALLED PRIOR TO 1975. ESTIMATED EMISSIONS ARE 18.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	POWERFORMER REHEATER, H205	NATURAL GAS*	48.8	MMBTU/H	Sulfur Dioxide (SO2)	A PRORATED CONCENTRATION OF THE FOLLOWING FUEL LIMITS IS CONSIDERED BACT: DIESEL FUEL, 0 35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			COMBINED EMISSIONS INFORMATION IS PROVIDED FOR SO2 AND H2S. ESTIMATED EMISSIONS OF SO2 ARE 6.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. ADDITIONAL EMISSION LIMITS ARE: A PRORATED CONCENTRATION OF THE FOLLOWING; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	HYDROCRACKER FRACTIONATER REBOILER, H403	NATURAL GAS*	50	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS COMBINED FOR SO2 AND H2S. ESTIMATED SO2 EMISSIONS ARE 6.6 T/YR. SOURCE IS ALSO SUBJECT TO NSPS. EMISSIONS LIMITS ARE A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	RESIDUAL OIL HEATER, H612	NATURAL GAS*	22.2	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT IS LIMITED AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION FOR SO2 AND H2S IS COMBINED. ESTIMATED SO2 EMISSIONS ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2. EMISSION LIMITS ARE A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	FIRED STEAM GENERATOR, H701	NATURAL GAS*	36 55	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED. THIS SOURCE IS NOT SUBJECT TO BACT-PSD AS IT WAS INSTALLED PRIOR TO 1975.	0		0			CONTROLS NOT INDICATED. ESTIMATED EMISSIONS ARE 4.8 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	FIRED STEAM GENERATOR, H702	NATURAL GAS*	36 55	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED. THIS SOURCE IS NOT SUBJECT TO BACT-PSD AS IT WAS INSTALLED PRIOR TO 1975.	0		0			ESTIMATED EMISSIONS ARE 4 8 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. EMISSION LIMITS, BASIS OF DETERMINATION, AND CONTROLS ARE NOT PROVIDED.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	NATURAL GAS SUPPLY HEATER, H704	NATURAL GAS*	2	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR EONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. ESTIMATED EMISSIONS OF SO2 ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	FIRED STEAM GENERATOR, H801	NATURAL GAS*	32	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	500	PPM	0			ESTIMATED EMISSIONS ARE 4 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	PRIP RECYCLER H2 FURNACE, H1202	NATURAL GAS*	11.2	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED SO2 EMISSIONS ARE 1 5 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	VACUUM TOWER HEATER, H1701	NATURAL GAS*	91	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED EMISSIONS OF SO2 ARE 12.0 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	HOT GLYCOL HEATER, H802	NATURAL GAS*	10.8	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS COMBINED FOR SO2 AND H2S. EMISSION LIMITS ARE A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER THREE HOURS AND 500 PPM SO2 AVERAGED OVER THREE HOURS. ESTIMATED EMISSIONS OF SO2 ARE 1.4 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	HYDROCRACKER STABILIZER REBOILER, H404	NATURAL GAS*	64.4	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR SO2 AND H2S. ESTIMATED SO2 EMISSIONS ARE 8.5 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS. EMISSION LIMITS ARE A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	#1 REHEATER STARTUP BURNER, H1102	NATURAL GAS*	1.65	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT IS LIMITED ACCORDING TO THE FOLLOWING: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0.01% H2S; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR H2S AND SO2. EMISSION LIMIT IS A PRORATED CONCENTRATION OF; 230 MG H2S/DSCF AVERAGED OVER THREE HOURS, AND 500 PPM SO2 AVERAGED OVER THREE HOURS. ESTIMATED SO2 EMISSIONS ARE 0.2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	#2 REHEATER STARTUP BURNER, H1103	NATURAL GAS*	1.15	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LPG, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION FOR H2S AND SO2. EMISSION LIMIT IS A PRORATED CONCENTRATION OF 230 MG H2S/DSCF AVERAGED OVER 3 HOURS AND 500 PPM SO2 AVERAGED OVER 3 HOURS. ESTIMATED SO2 EMISSIONS ARE 0 2 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0037	KENAI REFINERY	AK	03/21/2000 ACT	#3 REHEATER STARTUP BURNER, H1104	NATURAL GAS*	1 05	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS AS FOLLOWS: DIESEL FUEL, 0.35% SULFUR; NATURAL GAS, 0 01% SULFUR; LIQUIFIED PETROLEUM GAS, 0.01% SULFUR; REFINERY GAS, 168 PPMV H2S.	0		0			EMISSIONS INFORMATION IS PROVIDED IN COMBINATION WITH H2S. EMISSION LIMIT IS A PRORATED CONCENTRATION OF THE FOLLOWING; 230 MG H2S/DSCF AVERAGED OVER 3 HOURS, AND 500 PPM SO2 AVERAGED OVER 3 HOUR. ESTIMATED EMISSIONS OF SO2 ARE 0.1 T/YR, BUT THIS IS NOT AN EMISSION LIMIT. THIS SOURCE IS ALSO SUBJECT TO NSPS FOR SO2.
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	TURBINE, SIMPLE CYCLE, 11 2 MW	FUEL GAS	11.2	MW	Sulfur Dioxide (SO2)	LIMIT FUEL SULFUR CONTENT TO: 200 PPM FUEL GAS H2S, OR FUEL OIL SULFUR CONTENT 0.15% BY WEIGHT	150	PPM @ 15% O2	150	PPM @ 15% O2		DUEL FUEL FIRED TURBINE. OIL-FIRED OPERATIONS LIMITED TO 500 HRS ANNUALLY
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	TURBINE, SIMPLE CYCLE, 36,700 HP	FUEL GAS	27.4	MW	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPM	150	PPM @ 15% O2	150	PPM @ 15% O2		

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	TURBINE, SIMPLE CYCLE, 25 8 MW	FUEL GAS	25800	KW	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPM	150	PPM @ 15% O2	0			
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	HEATER, CRUDE PRODUCTION, 65.6 MMBTU/H	FUEL GAS	65.6	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPMV	0		0			Fuel limit -- no emission rate limit.
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	HEATER, CRUDE PRODUCTION, 65.6 MMBTU/H	FUEL GAS	65.6	MMBTH/H	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPMV.	0		0			fuel sulfur limit -- no emission rate limit
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	HEATER, UHM, 20 MMBTU/H	FUEL GAS	20	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPMV WHEN OPERATING USING LIQUID FUEL: FUEL SULFUR LIMIT OF 215 NG/J (0.50 LB/MMBTU) HEAT INPUT; OR, AS AN ALTERNATIVE, 0.5 WEIGHT PERCENT SULFUR.	0		0			limit is fuel sulfur limit. No emission rate limit
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	HEATER, HMU, 20 MMBTU/H	FUEL GAS	20	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPMV WHEN OPERATING ON FUEL OIL: FUEL SULFUR LIMIT OF 215 NG/J (0.50 LB/MMBTU) HEAT INPUT; OR, AS AN ALTERNATIVE, 0 5 WEIGHT PERCENT SULFUR.	0		0			limit is fuel sulfur limits. No emission rate limits
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	IC ENGINES, 2 MW	FUEL OIL	2	MW	Sulfur Dioxide (SO2)	FUEL OIL SULFUR CONTENT NOT TO EXCEED 0.15% SULFUR BY WEIGHT	0		0			SULFUR LIMIT ON FUEL
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	DISTILLATE HYDROTREATER CHARGE HEATER	REFINERY FUEL GAS OR NATURAL GAS	25	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	DISTILLATE HYDROTREATER SPLITTER REBOILER	REFINERY FUEL GAS OR NATURAL GAS	117	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	TANK FARM THERMAL OXIDIZER	REFINERY FUEL GAS AND GASES FROM TANKS			Sulfur Dioxide (SO2)		35	PPMV	0			THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	WASTEWATER TREATMENT PLANT THERMAL OXIDIZER	NATURAL GAS OR REFINERY FUEL GAS			Sulfur Dioxide (SO2)	35 PPM SULFUR LIMIT IN FUEL.	35	PPMV	0			THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SULFER PIT NOS. 1 AND 2				Sulfur Dioxide (SO2)	ALL GASES DISCHARGED FROM THE SULFUR PITS MUST BE COLLECTED AND ROUTED TO THE FRONT OF EITHER SULFER RECOVERY UNIT 1 OR UNIT 2.	33.5	LB/H	0		NOT AVAILABLE	THE SULFUR LIMIT IS FOR ANY GASES FROM THE SULFUR RECOVERY PLANT.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	CATALYTIC REFORMING UNIT CHARGE HEATER	REFINERY FUEL GAS AND NATURAL GAS	122	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR LIMITED TO 35 PPM IN FUEL.	35	PPMV	0		NOT AVAILABLE	THE 35 PPMV SULFUR LIMIT, AS H2S, IS A RESTRICTION ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS BEING FIRED IN THE UNIT.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	TRUCK AND RAIL CAR LOADING RACK THERMAL OXIDIZERS	REFINERY FUEL GAS OR NATURAL GAS	12.3	MMBTU/H	Sulfur Dioxide (SO2)		35	PPMV	0			THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	CATALYTIC REFORMING UNIT INTERHEATER NO. 1	REFINERY FUEL GAS AND NATURAL GAS	192	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	35	PPMV	0		NOT AVAILABLE	THE 35 PPMV SULFUR LIMIT, AS H2S, IS A RESTRICTION ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS BEING FIRED IN THE UNIT.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	CATALYTIC REFORMING UNIT INTERHEATER NO. 2	REFINERY FUEL GAS OR NATURAL GAS	129	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	CATALYTIC REFORMING UNIT DEBUTANIZER REBOILER	REFINERY FUEL GAS OR NATURAL GAS	23.2	MMBTU/H	Sulfur Dioxide (SO2)	S LIMIT OF 35 PPM.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	BUTANE CONVERSION UNIT DEHYDROGENATION REACTOR CHARGE HEATER	REFINERY FUEL GAS OR NATURAL GAS	311	MMBTU/H	Sulfur Dioxide (SO2)	35 PPM SULFUR LIMIT ON FUEL BURNED.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	BUTANE CONVERSION UNIT DEHYDROGENATION REACTOR INTERHEATER	REFINERY FULE GAS OR NATURAL GAS	328	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR LIMIT OF 35 PPM IN FUEL BURNED.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	VACUUM CRUDE CHARGE HEATER	REFINERY FUEL GAS OR NG	101	MMBTU/H	Sulfur Dioxide (SO2)		35	PPMV	0		NOT AVAILABLE	THIS LIMIT IS FOR SULFUR, AS H2S, AND IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	HYDROCRACKER UNIT CHARGE HEATER	REFINERY FUEL GAS OR NG	70	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	35	PPMV	0		NOT AVAILABLE	THIS LIMIT FOR SULFUR, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	HYDROCRACKER UNIT MAIN FRACTIONATOR HEATER	REFINERY FUEL GAS OR NG	211	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM.	35	PPMV	0		NOT AVAILABLE	THIS LIMIT ON SULFUR, AS H2S, IS A RESTRICTION ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	NAPHTHA HYDROTREATER CHARGE HEATER	REFINERY FUEL GAS OR NG	21.4	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM	35	PPMV	0		NOT AVAILABLE	THIS LIMIT ON SULFUR, AS H2S, IS A RESTRICTION ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	BUTANE CONVERSION UNIT ISOSTRIPPER REBOILER	REFINERY FUEL GAS AND NATURAL GAS	222	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR LIMITED TO 35 PPM IN FUEL BURNED.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	ATMOSPHERIC CRUDE CHARGE HEATER	NATURAL GAS OR REFINERY FUEL GAS	346	MMBTU/H	Sulfur Dioxide (SO2)	35 PPM SULFUR LIMIT IN FUEL.	35	PPMV	0		NOT AVAILABLE	THE 35 PPMV SULFUR LIMIT, AS H2S, IS A RESTRICTION ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS BEING FIRED IN THE UNIT.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	HYDROGEN REFORMER HEATER	REFINERY FUEL GAS OR NATURAL GAS	1435	MMBTU/H	Sulfur Dioxide (SO2)	S LIMITED TO 35 PPM	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SPRAY DRYER HEATER	REFINERY FUEL GAS OR NATURAL GAS	44	MMBTU/H	Sulfur Dioxide (SO2)		35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SULFUR RECOVERY UNITS 1 AND 2				Sulfur Dioxide (SO2)	ALL GASES DISCHARGED FROM THE SULFUR RECOVERY UNITS MUST BE COLLECTED AND ROUTED TO THE FRONT OF EITHER SULFER RECOVERY UNIT 1 OR UNIT 2.	33.5	LB/H	0		NOT AVAILABLE	THE SULFUR LIMIT IS FOR ANY GASES FROM THE SULFUR RECOVERY PLANT.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	TAIL GAS TREATMENT UNIT				Sulfur Dioxide (SO2)	ALL GASES DISCHARGED FROM THE TAIL GAS TREATMENT UNIT MUST BE ROUTED TO THE SULFUR RECOVERY PLANT THERMAL OXIDIZER	33.5	LB/H	0		NOT AVAILABLE	THE SULFUR LIMIT IS FOR ANY GASES FROM THE SULFUR RECOVERY PLANT.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SULFUR RECOVERY PLANT THERMAL OXIDIZER	REFINERY FUEL GAS OR NATURAL GAS	100	MMBTU/H	Sulfur Dioxide (SO2)		33.5	LB/H	0		NOT AVAILABLE	THE SULFUR LIMIT IS FOR ANY GASES FROM THE SULFUR RECOVERY PLANT.
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	SULFUR RECOVERY PLANT THERMAL OXIDIZER	REFINERY FUEL GAS OR NATURAL GAS	100	MMBTU/H	Sulfur, Total Reduced (TRS)		0 089	LB/H	0		NOT AVAILABLE	
AZ-0046	ARIZONA CLEAN FUELS YUMA	AZ	04/14/2005 ACT	DELAYED COKING UNIT CHARGE HEATER NOS. 1 AND 2	REFINERY FUEL GAS OR NATURAL GAS	99.5	MMBTU/H	Sulfur Dioxide (SO2)	FUEL LIMITED TO 35 PPM S.	35	PPMV	0		NOT AVAILABLE	THIS SULFUR LIMIT, AS H2S, IS A LIMIT ON THE INLET CONCENTRATION OF THE REFINERY FUEL GAS.
CO-0046	EXCEL CORPORATION - FT. MORGAN	CO	04/27/2000 ACT	WASTE WATER TREATMENT PLANT		54	MMGAL/MO	Sulfur Dioxide (SO2)	SULFUR RECOVERY SYSTEM, LOW SULFUR CONTENT WATER.	98	% REDUCTION	0			
CO-0046	EXCEL CORPORATION - FT. MORGAN	CO	04/27/2000 ACT	FLARE (B-9)	BIOGAS	67.5	MMBTU/H	Sulfur Dioxide (SO2)	ALL LIMITS ARE ON A FACILITY WIDE BASIS, NO OTHER INFORMATION IS AVAILABLE.	98	% REDUCTION	0			
CO-0046	EXCEL CORPORATION - FT. MORGAN	CO	04/27/2000 ACT	STEAM BOILER (B-1)	NATURAL GAS / BIOGAS	20.9	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR RECOVERY SYSTEM. ALL LIMITS ARE ON A FACILITY WIDE BASIS, NO OTHER INFORMATION AVAILABLE.	98	% REDUCTION	0			
CO-0046	EXCEL CORPORATION - FT. MORGAN	CO	04/27/2000 ACT	STEAM BOILER 2 (B-3)	NATURAL GAS/BIOGAS	25.1	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR RECOVERY SYSTEM. ALL LIMITS ON A FACILITY WIDE BASIS, NO OTHER INFORMATION IS AVAILABLE.	98	% REDUCTION	0			
FL-0318	HIGHLANDS ETHANOL FACILITY	FL	12/10/2009 EST	Emergency Fired Pump	ULSD fuel oil	0		Sulfur Dioxide (SO2)	Ultra low sulfur fuel oil (ULSFO)	0.0015	% S	0			The fire pump engine is an Emergency Stationary Compression Ignition Internal Combustion Engine (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII.
FL-0318	HIGHLANDS ETHANOL FACILITY	FL	12/10/2009 EST	Backup 198 mmBtu/hr boiler	Natural gas	0		Sulfur Dioxide (SO2)		0.0056	LB/MMBTU	0			Use of low sulfur fossil fuels such as ULSD FO, natural gas or propane in the backup boiler insures that uncontrolled SO2 emissions are less than 0.32 lb SO2/mmBtu. Therefore, no specific limit from 40 CFR 60, NSPS Subpart Db applies to the backup boiler.
FL-0318	HIGHLANDS ETHANOL FACILITY	FL	12/10/2009 EST	198 mmBtu/hr Biomass Fueled Boiler	Stillage & biomass	198	MMBTU	Sulfur Dioxide (SO2)	Limestone injection in the BFB boilers to control SO2 and HCl	0.06	LB/MMBTU	0			A
FL-0318	HIGHLANDS ETHANOL FACILITY	FL	12/10/2009 EST	Emergency Generators		0		Sulfur Dioxide (SO2)		0.0015	% S	0			These emergency generators are Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and shall comply with applicable provisions of 40 CFR 60, Subpart IIII, including emission testing or certification.
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	CRUDE HEATER (2)	NAT & REFINERY GAS	281.1	MMBTU/H (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	11.25	LB/H	0.0044	LB/MMBTU	EACH, CALCULATED	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	LGO HYDROCARBON CHARGE HEATER	NAT & REFINERY GAS	69.4	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	2.78	LB/H	0 04	LB/MMBTU	CALCULATED	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	LGO HYDROCARBON STRIPPER REBOILER		62.1	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	2.49	LB/H	0 04	LB/MMBTU	CALCULATED	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	DEASPHALTING HEATER	NAT & REFINERY GAS	221	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	8.85	LB/H	0 04	LB/MMBTU	CALCULATED	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	MARINE LOADING VAPOR COMBUSTOR		50000	BBL	Sulfur Dioxide (SO2)	NONE INDICATED	0.13	LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	HGO HYDROCARBON CHARGE HEATER		98.8	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	3.95	LB/H	0 04	LB/MMBTU	CALCULATED	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	BOILER NO. 1	NAT & REFINERY GAS	350	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL	11.21	LB/H	0.032	LB/MMBTU		
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	HF ALKYLATION MAIN FRACTIONATOR REBOILER	NAT & REFINERY GAS	268.6	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	10.75	LB/H	0 04	LB/MMBTU	CALCULATED	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	HGO HYDROCARBON STRIPPER REBOILER	NAT & REFINERY GAS	78	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	3.13	LB/H	0 04	LB/MMBTU	CALCULATED	
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	SULFUR RECOVERY UNIT #3				Sulfur Dioxide (SO2)	AMINE BASED SCRUBBER (CLAUS/MDEA) AND THERMAL OXIDIZER	56.86	LB/H	60	PPMV @ 0% EXCESS AIR	EMISSION CAP, SEE NOTES	SULFUR RECOVERY UNIT EMISSIONS FROM THERMAL OXIDIZERS #1, #2, AND #3 ARE CONTROLLED UNDER A CAP, TOTAL SO2 EMMISIONS NOT TO EXCEED 398.52 T/YR (60 PPMV)
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	SULFUR RECOVERY UNITS NO. 1 AND NO. 2				Sulfur Dioxide (SO2)	AMINE BASED SCRUBBER (CLAUS/MDEA)AND THERMAL OXIDIZER.	56.86	LB/H	60	PPMV @ 0% EXCESS AIR	EMISSION CAP, SEE NOTES	SULFUR RECOVERY UNIT EMISSIONS FROM THERMAL OXIDIZERS #1, #2, AND #3 ARE CONTROLLED UNDER A CAP, TOTAL SO2 EMMISIONS NOT TO EXCEED 398.52 T/YR (60 PPMV)
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	COKER HEATER		241.1	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL	9.64	LB/H	0 04	LB/MMBTU		
LA-0149	LOUISIANA REFINING DIVISION	LA	10/21/1999 ACT	SULFUR PLANT NO. 3 FUGITIVES				Sulfur Dioxide (SO2)		0.07	LB/H	0			THERE IS AN EMISSION CAP FOR MAXIMUM SO2 EMISSIONS
LA-0166	ORION REFINING CORP (NOW VALERO)	LA	01/10/2002 ACT	FCC REGENERATOR		110	TO 130 MBBL/D	Sulfur Dioxide (SO2)	BELCO WET GAS SCRUBBER	450	LB/H	0		NOT AVAILABLE	
LA-0166	ORION REFINING CORP (NOW VALERO)	LA	01/10/2002 ACT	HEATER F-72-703	REFINERY FUEL GAS	528	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR REFINERY FUEL GAS	14.2	LB/H	0.027	LB/MMBTU		
LA-0166	ORION REFINING CORP (NOW VALERO)	LA	01/10/2002 ACT	MARINE TANK VESSEL LOADING OPERATIONS				Sulfur Dioxide (SO2)	NONE INDICATED	3.3	LB/H	0			
LA-0166	ORION REFINING CORP (NOW VALERO)	LA	01/10/2002 ACT	HEATER H-15-01A		46	MMBTU/H	Sulfur Dioxide (SO2)	COMBUSTION OF LOW SULFUR FUEL	1.2	LB/H	0.0261	LB/MMBTU		
LA-0166	ORION REFINING CORP (NOW VALERO)	LA	01/10/2002 ACT	HEATER H-15-01B		46	MMBTU/H	Sulfur Dioxide (SO2)	COMBUSTION OF LOW SULFUR FUELS	1.2	LB/H	0.0261	LB/MMBTU		
LA-0166	ORION REFINING CORP (NOW VALERO)	LA	01/10/2002 ACT	SULFUR RECOVERY UNITS 1 AND 2				Sulfur Dioxide (SO2)	EFFICIENCY OF SULFUR RECOVERY PROCESS TOGETHER WITH OXIDATION OF RESIDUAL SULFUR COMPOUNDS LIMITS SO2 EMISSIONS TO 250 PPM	103	LB/H	250	PPMV	@ 0% EXCESS AIR	
LA-0166	ORION REFINING CORP (NOW VALERO)	LA	01/10/2002 ACT	SULFUR RECOVERY UNIT NO. 3				Sulfur Dioxide (SO2)	EFFICIENCY OF SULFUR RECOVERY PROCESS TOGETHER WITH OXIDATION OF RESIDUAL SULFUR COMPOUNDS LIMITS SO2 EMISSIONS TO 250 PPM	5	LB/H	250	PPMV	@ 0% EXCESS AIR	
LA-0166	ORION REFINING CORP (NOW VALERO)	LA	01/10/2002 ACT	FLARE NO.1 (EMISSION PT. 15-77)		60.7	MMBTU/H	Sulfur Dioxide (SO2)		133	LB/H	0			
LA-0166	ORION REFINING CORP (NOW VALERO)	LA	01/10/2002 ACT	FLARE NO. 2 (EMISSION PT. 12-81)		60.7	MMBTU/H	Sulfur Dioxide (SO2)		133	LB/H	0			
LA-0166	ORION REFINING CORP (NOW VALERO)	LA	01/10/2002 ACT	SPENT SULFURIC ACID STORAGE				Sulfur Dioxide (SO2)	FIXED ROOF STORAGE TANK AND SUBMERGED FILL LOADING	1.1	LB/H	0			
LA-0166	ORION REFINING CORP (NOW VALERO)	LA	01/10/2002 ACT	SPENT SULFURIC LOADING				Sulfur Dioxide (SO2)	FIXED ROOF STORAGE TANK AND SUBMERGED FILL LOADING	1.1	LB/H	0			
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	PIPESTILL, COKER, HYDROCRACKING, & LIGHT ENDS FURNACES				Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0 034	LB/MMBTU	0.034	LB/MMBTU		
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	PIPESTILL, COKER, CAT COMPLEX, & LIGHT ENDS FURNACES				Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0 034	LB/MMBTU	0.034	LB/MMBTU		
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	REFORMING, HYDROFINING, & HEAVY CAT FURNACES				Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0 034	LB/MMBTU	0.034	LB/MMBTU		
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	FEED PREPARATION FURNACES F-30 & F-31		352	MMBTU/H	Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0.1778	LB/MMBTU	0.1778	LB/MMBTU		
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	CRU REGENERATOR VENT		329	UNITS/YR	Sulfur Dioxide (SO2)	GOOD ENGINEERING DESIGN AND PROPER OPERATION	0.88	LB/H	0			
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	POWERFORMING & LIGHT ENDS FURNACES				Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0.1778	LB/MMBTU	0.1778	LB/MMBTU		

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
LA-0206	BATON ROUGE REFINERY	LA	02/18/2004 ACT	POWERFORMING 2 & EAST LIGHT ENDS FURNACES				Sulfur Dioxide (SO2)	LIMIT CONCENTRATION OF H2S IN FUEL GAS TO NSPS SUBPART J LIMIT OF 160 PPMV (0.01 GR/DSCF)	0.1778	LB/MMBTU	0.1778	LB/MMBTU		
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	NAPHTHA HYDROTREATER REACTOR CHARGE HEATER (5-08), KHT REACTOR CHARGE HEATER (9-08), & HCU TRAIN 1&2 REACTOR CHARGE HEATERS (11-08 & 12-08)	REFINERY FUEL GAS			Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV AS H2S	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	NAPHTHA HYDROTREATER STRIPPER REBOILER HEATER (6-08) & KHT STRIPPER REBOILER HEATER (10-08)	REFINERY FUEL GAS			Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV AS H2S	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	BOILER NO. 1 (16-08)	REFINERY FUEL GAS	525.7	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	SRU THERMAL OXIDIZER NOS. 1 & 2 (18-08 & 19-08)	NATURAL GAS	63.7	MM BTU/H EA.	Sulfur Dioxide (SO2)	SEE NOTES	93.41	PPMVD	0			OXYGEN ENRICHMENT AND SULFUR SHEDDING PROCEDURES WITH AUTOMATED CONTROLS WITHIN THE SRU; EXCESS SRU CAPACITY; DEGASSING THE LIQUID SULFUR PRODUCT UPSTREAM OF THE SULFUR PIT TO <= 15 PPMV H2S; RECYCLING SULFUR PIT VENTS TO THE SRU INLET; PROPER OPERATING PRACTICES FOR SOUR WATER STORAGE; OVERALL SULFUR CONVERSION EFFICIENCY OF 99.9%; THERMAL OXIDIZER CONVERSION EFFICIENCY OF 99.5%
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	EMERGENCY GENERATORS (DOCK & TANK FARM) (21-08 & 22-08)	DIESEL			Sulfur Dioxide (SO2)		0.02	MAX LB/H	0			USE OF DIESEL WITH A SULFUR CONTENT OF 15 PPMV OR LESS.
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	A & B CRUDE HEATERS (1-08 & 2-08) & COKER CHARGE HEATER (15-08)	REFINERY FUEL GAS			Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	HYDROGEN REFORMER FURNACE FLUE GAS VENT (48-08)	PURGE GAS	1412.5	MMBTU/H	Sulfur Dioxide (SO2)	USE OF LOW SULFUR FUEL GAS	25	PPMV AS H2S	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	PLATFORMER HEATER CELLS NO. 1-3 (7A-08, 7B-08, & 7C-08) & HCU FRACTIONATOR HEATER (13-08)	REFINERY FUEL GAS			Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV AS H2S	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	A & B VACUUM TOWER HEATERS (3-08 & 4-08)	REFINERY FUEL GAS	155.2	MMBTU/H EA.	Sulfur Dioxide (SO2)	USE OF LOW SULFUR REFINERY FUEL GAS	25	PPMV	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	FCCU REGENERATOR VENT (86-74)				Sulfur Dioxide (SO2)	VENTURI WET GAS SCRUBBER W/ ADDITION OF CAUSTIC SOLUTION	25	PPMV@0%02	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	MARINE VAPOR COMBUSTOR (55-08) & MARINE LOADING VAPOR COMBUSTOR (107-90)		50000	BBL/H EA.	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60.18.	0		0			NO EMISSION LIMITS AVAILABLE
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	THERMAL DRYING UNIT HEATEC HEATER (124-1-91)	REFINERY FUEL GAS	9.6	MM BTU/H	Sulfur Dioxide (SO2)		0.2	MAX LB/H	0			
LA-0211	GARYVILLE REFINERY	LA	12/27/2006 ACT	HYDROGEN PLANT FLARE (52-08)	H2 PLANT FEED GAS	2472	MMBTU/H	Sulfur Dioxide (SO2)	COMPLY WITH 40 CFR 60.18	0.01	MAX LB/H	0			
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	STARTUPS/SHUTDOWNS - SRU				Sulfur Dioxide (SO2)	FOLLOW WRITTEN SOP, MINIMIZE DURATION AND FREQUENCY, PROPERLY DOCUMENT ALL SU/SD	0		0			NO EMISSION LIMITS AVAILABLE
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	BOILERS (94-43 & 94-45)	REFINERY FUEL GAS	354	MMBTU/H EA	Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE).	9.43	LB/H	0			
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	FLARE 1-5 (15-77, 12-81, 2004-5A, 2004-5B & 2005-38)				Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE) AS FUELS AT FLARE TIP.	0		0			NO EMISSION LIMITS AVAILABLE
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	SRU THERMAL OXIDIZERS (99-3, 99-4, 2005-39, 2007-4)		50	MMBTU/H	Sulfur Dioxide (SO2)	CONTROL DEVICE - COMPLY WITH 40 CFR 60 SUBPART J	250	PPMVD	0			
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	FCCU REGENERATOR (16-77)				Sulfur Oxides (SOx)	WET SCRUBBER	176.12	LB/H	50	PPMV	7 DAY ROLLING AVERAGE	
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	MVR THERMAL OXIDIZER NO. 1 (94-8)		240	MMBTU/H	Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE).	3.3	LB/H	0			
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	ARU FLARE (2008-36)	PROCESS FUEL GAS			Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR PROCESS FUEL GAS WITH H2S <= 10 PPMV (ANNUAL AVERAGE)	0		0			NO EMISSION LIMITS AVAILABLE

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	HEATERS/REBOILERS	REFINERY FUEL GAS			Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE).	0		0			NO EMISSION LIMITS
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	HEATERS (2008-1 - 2008-9)	PROCESS FUEL GAS			Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR PROCESS FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 10 PPMV (ANNUAL AVERAGE).	0		0			NO EMISSION LIMITS
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	MVR THERMAL OXIDIZER NO. 2 (2008-38)	REFINERY FUEL GAS	200	MMBTU/H	Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR PROCESS FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 10 PPMV (ANNUAL AVERAGE).	0.45	LB/H	0			
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	HEATERS (94-21 & 94-29)	REFINERY FUEL GAS			Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE).	0		0			NO EMISSION LIMITS AVAILABLE
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	CPF HEATER H-39-03 & H-39-02 (94-28 & 94-30)	REFINERY FUEL GAS			Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY NATURAL GAS OR REFINERY FUEL GASES WITH AN H2S CONCENTRATION LESS THAN 100 PPMV (ANNUAL AVERAGE).	0		0			NO EMISSION LIMITS
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	BOILERS (2008-10, 2008-11, 2008-40)	REFINERY FUEL GAS	715	MMBTU/H EA	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS AND/OR REFINERY FUEL GAS WITH H2S <= 100 PPMV (ANNUAL AVERAGE) OR PROCESS FUEL GAS WITH H2S <= 10 PPMV (ANNUAL AVERAGE)	0		0			NO EMISSION LIMITS AVAILABLE
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	DHT HEATERS (4-81, 5-81)	REFINERY FUEL GAS	70	MMBTU/H EA	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR REFINERY FUEL GAS WITH H2S <= 100 PPMV (ANNUAL AVERAGE)	0		0			NO EMISSION LIMITS AVAILABLE
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	HEATER F-72-703 (7-81)	REFINERY FUEL GAS	633	MMBTU/H	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS OR REFINERY FUEL GAS WITH H2S <= 100 PPMV (ANNUAL AVERAGE)	0		0			NO EMISSION LIMITS AVAILABLE
LA-0213	ST. CHARLES REFINERY	LA	11/17/2009 ACT	THERMAL OXIDIZERS (2008-32, 2008-33, 2008-34)	PROCESS FUEL GAS	15	MMBTU/H EA	Sulfur Dioxide (SO2)	FUELED BY NATURAL GAS AND PROCESS FUEL GAS WITH H2S <=10 PPMV (ANNUAL AVERAGE)	0		0			NO EMISSION LIMITS AVAILABLE
LA-0234	LAKE CHARLES COMPLEX - CAT GAS HYDRO	LA	01/26/2009 ACT	3(XXXIV)7-102 FURNACE B-102	FUEL GAS	62.8	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR CONCENTRATION IN THE FUEL GAS	5.08	LB/H	0			ORIGINAL PSD ESTABLISHED AN AVERAGE SULFUR CONCENTRATION OF 182 PPM AND A MAXIMUM OF 332 PPM IN THE FUEL GAS. THIS RECONCILIATION AFTER DETERMINING MORE UPDATED SULFUR CONCENTRATIONS RAISES THOSE VALUES TO AN AVERAGE OF 218.4 PPM AND A MAXIMUM OF 475 PPM IN THE FUEL GAS.
LA-0234	LAKE CHARLES COMPLEX - CAT GAS HYDRO	LA	01/26/2009 ACT	3(XXXIV)7-201 FURNACE B-201	FUEL GAS	56.9	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR CONCENTRATION IN THE FUEL GAS	5.08	LB/H	0			ORIGINAL PSD ESTABLISHED AN AVERAGE SULFUR CONCENTRATION OF 182 PPM AND A MAXIMUM OF 332 PPM IN THE FUEL GAS. THIS RECONCILIATION AFTER DETERMINING MORE UPDATED SULFUR CONCENTRATIONS RAISES THOSE VALUES TO AN AVERAGE OF 218.4 PPM AND A MAXIMUM OF 475 PPM IN THE FUEL GAS.
LA-0234	LAKE CHARLES COMPLEX - CAT GAS HYDRO	LA	01/26/2009 ACT	3(XXXIV)7-202 FURNACE B-202	FUEL GAS	56.9	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR CONCENTRATION IN THE FUEL GAS	5.08	LB/H	0			ORIGINAL PSD ESTABLISHED AN AVERAGE SULFUR CONCENTRATION OF 182 PPM AND A MAXIMUM OF 332 PPM IN THE FUEL GAS. THIS RECONCILIATION AFTER DETERMINING MORE UPDATED SULFUR CONCENTRATIONS RAISES THOSE VALUES TO AN AVERAGE OF 218.4 PPM AND A MAXIMUM OF 475 PPM IN THE FUEL GAS.
LA-0234	LAKE CHARLES COMPLEX - CAT GAS HYDRO	LA	01/26/2009 ACT	3(XXXIV)7-103 REBOILER B-103	FUEL GAS	38.3	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR CONCENTRATION IN THE FUEL GAS	3.1	LB/H	0			ORIGINAL PSD ESTABLISHED AN AVERAGE SULFUR CONCENTRATION OF 182 PPM AND A MAXIMUM OF 332 PPM IN THE FUEL GAS. THIS RECONCILIATION AFTER DETERMINING MORE UPDATED SULFUR CONCENTRATIONS RAISES THOSE VALUES TO AN AVERAGE OF 218.4 PPM AND A MAXIMUM OF 475 PPM IN THE FUEL GAS.
LA-0234	LAKE CHARLES COMPLEX - CAT GAS HYDRO	LA	01/26/2009 ACT	3(XXXIV)7-203 REBOILER B-203	FUEL GAS	38.3	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR CONCENTRATION IN THE FUEL GAS	3.1	LB/H	0			ORIGINAL PSD ESTABLISHED AN AVERAGE SULFUR CONCENTRATION OF 182 PPM AND A MAXIMUM OF 332 PPM IN THE FUEL GAS. THIS RECONCILIATION AFTER DETERMINING MORE UPDATED SULFUR CONCENTRATIONS RAISES THOSE VALUES TO AN AVERAGE OF 218.4 PPM AND A MAXIMUM OF 475 PPM IN THE FUEL GAS.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
LA-0234	LAKE CHARLES COMPLEX - CAT GAS HYDRO	LA	01/26/2009 ACT	3(XXXIV)7-101 FURNACE B-101	FUEL GAS	62.8	MMBTU/H	Sulfur Dioxide (SO2)	USE LOW SULFUR CONCENTRATION FUEL GAS.	5.08	LB/H	0			ORIGINAL PSD ESTABLISHED AN AVERAGE SULFUR CONCENTRATION OF 182 PPM AND A MAXIMUM OF 332 PPM IN THE FUEL GAS. THIS RECONCILIATION AFTER DETERMINING MORE UPDATED SULFUR CONCENTRATIONS RAISES THOSE VALUES TO AN AVERAGE OF 218.4 PPM AND A MAXIMUM OF 475 PPM IN THE FUEL GAS.
NJ-0053	MCUA	NJ	03/09/1999 ACT	DUCT FIRED HRSG	LANDFILL GAS	31	MMBTU/H NOMINAL *	Sulfur Dioxide (SO2)	NONE	1.73	LB/H	0 04	LB/MMBTU		
NJ-0053	MCUA	NJ	03/09/1999 ACT	TURBINE WITH HRSG	LANDFILL GAS	74	MMBTU/H	Sulfur Dioxide (SO2)	NONE	4.71	LB/H	0			
NJ-0053	MCUA	NJ	03/09/1999 ACT	OPEN FLARE	LANDFILL GAS	90	MMBTU/H*	Sulfur Dioxide (SO2)	NONE	3.6	LB/H	0			ADDITIONAL EMISSION LIMIT: 0.04 LB/MMBTU
NJ-0053	MCUA	NJ	03/09/1999 ACT	LANDFILL GAS TURBINE	LANDFILL GAS	65	MMBTU/H (NOMINAL)*	Sulfur Dioxide (SO2)	NONE	2.98	LB/H	0			
NJ-0061	MERCK-RAHWAY PLANT	NJ	09/18/2003 ACT	BOILERS (2) - NATURAL GAS CO-FIRED WITH WASTE SOLVENT	NATURAL GAS CO-FIRED WITH WASTE SOLVENT	99.5	MMBTU/H	Sulfur Dioxide (SO2)	THE USE OF LOW SULFUR CONTENT IN FUEL : 0 055 % SULFUR IN FUEL BY WEIGHT FOR THE MIXTURE OF NATURAL GAS AND WASTE SOLVENT IS CONSIDERED BACT FOR SO2.	5.1	LB/H	0			
PA-0231	UNITED REFINERY CO.	PA	10/09/2003 ACT	DELAYED COKER UNIT, HEATER	REFINERY GAS	116	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR REFINERY GAS	2.71	LB/H	0.023	LB/MMBTU	Calculated using heat input	Best available technology (BAT) review done.
PA-0231	UNITED REFINERY CO.	PA	10/09/2003 ACT	FCC FEED HYDROTREATER HEATER	REFINERY GAS	91	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR REFINERY GAS	2.44	LB/H	0.027	LB/MMBTU	Calculated using heat input	Best available technology (BAT) review done.
PA-0231	UNITED REFINERY CO.	PA	10/09/2003 ACT	HYDROGEN REFORMER UNIT	REFINERY GAS	344	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE	9.22	LB/H	0			Best available technology (BAT) review done.
PA-0231	UNITED REFINERY CO.	PA	10/09/2003 ACT	NORTH CRUDE HEATER	REFINERY GAS	147	MMBTU/H	Sulfur Dioxide (SO2)	USE OF DESULFURIZED REFINERY GAS	46.22	LB/H	0.3	LB/MMBTU	Calculated using heat input	Best available technology (BAT) review done.
TX-0322	CITGO CORPUS CHRISTI REFINERY-WEST PLANT	TX	10/15/1999 ACT	COKER HEATER, 521-H1		291	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	9.19	LB/H	0.032	LB/MMBTU		
TX-0322	CITGO CORPUS CHRISTI REFINERY-WEST PLANT	TX	10/15/1999 ACT	MIXED DIST HYDROTREATER CHARGE HEATER, 527-H1		62	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	5.82	LB/H	0.094	LB/MMBTU	CALCULATED FROM HEAT INPUT	INCLUDES 3.86 LB/H OF SO2 FROM BURNING MEROX UNIT VENT GAS. MEROX VENT GAS CONTAINS 0 0056 MOL S/MOL VENT GAS.
TX-0322	CITGO CORPUS CHRISTI REFINERY-WEST PLANT	TX	10/15/1999 ACT	MIXED DIST HYDROTREATER REBOILER HEATER, 527-H2		82	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	2.6	LB/H	0.032	LB/MMBTU	CALCULATD FROM HEAT INPUT	
TX-0322	CITGO CORPUS CHRISTI REFINERY-WEST PLANT	TX	10/15/1999 ACT	FLARE - COKE DRUM BLOWDOWN, 573-ME1				Sulfur Dioxide (SO2)	NONE INDICATED	528	LB/H	0			
TX-0322	CITGO CORPUS CHRISTI REFINERY-WEST PLANT	TX	10/15/1999 ACT	TAIL GAS INCINERATOR, 554-ME5		9	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	12.52	LB/H	0			
TX-0322	CITGO CORPUS CHRISTI REFINERY-WEST PLANT	TX	10/15/1999 ACT	NO. 3 BOILER, 561-B3		99	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	3.13	LB/H	0.032	LB/MMBTU	CALCULATED FROM HEAT INPUT	
TX-0348	DIAMOND SHAMROCK MCKEE PLANT	TX	10/19/2001 ACT	SPLITTER REBOILER HEATER, H-66	FUEL GAS	38.5	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.46	LB/H	0.038	LB/MMBTU	CALCULATED	STANDARD EMISSION LIMITS CALCULATED FROM HOURLY LIMITS AND PROCESS RATING.
TX-0348	DIAMOND SHAMROCK MCKEE PLANT	TX	10/19/2001 ACT	NO. 3 REFORMER CHARGE HEATERS H-67A, H-67B, H-67C	FUEL GAS	160.4	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	6.07	LB/H	0.038	LB/MMBTU	CALCULATED	STANDARD EMISSION LIMITS CALCULATED FROM HOURLY LIMITS AND PROCESS RATING.
TX-0348	DIAMOND SHAMROCK MCKEE PLANT	TX	10/19/2001 ACT	NO. 3 REFORMER STABILIZER REBOILER HEATER, H-68	FUEL GAS	13.5	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.51	LB/H	0.038	LB/MMBTU	CALCULATED	STANDARD EMISSION LIMITS CALCULATED FROM HOURLY LIMITS AND PROCESS RATING.
TX-0348	DIAMOND SHAMROCK MCKEE PLANT	TX	10/19/2001 ACT	NO. 3 SRU HEAT TRANSFER HEATER, H-69	FUEL GAS	10.8	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.41	LB/H	0.038	LB/MMBTU	CALCULATED	STANDARD EMISSION LIMITS CALCULATED FROM HOURLY LIMITS AND PROCESS RATING.
TX-0348	DIAMOND SHAMROCK MCKEE PLANT	TX	10/19/2001 ACT	NO. 4 HYDROTREATER CHARGE HEATER, H-64	FUEL GAS	30.1	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.14	LB/H	0.038	LB/MMBTU	CALCULATED	STANDARD EMISSION LIMITS CALCULATED BY DIVIDING THE HOURLY EMISSION LIMIT BY THE THROUGHPUT.
TX-0348	DIAMOND SHAMROCK MCKEE PLANT	TX	10/19/2001 ACT	NO. 4 HYDROTREATER STRIPPER REBOILER HEATER, H-65	FUEL GAS	37	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	1.4	LB/H	0.038	LB/MMBTU	CALCULATED	STANDARD EMISSION LIMITS CALCULATED FROM HOURLY LIMITS AND PROCESS RATING.
TX-0348	DIAMOND SHAMROCK MCKEE PLANT	TX	10/19/2001 ACT	NO. 3 SRU TAIL GAS INCINERATOR, V-27				Sulfur Dioxide (SO2)	NONE INDICATED	22.27	LB/H	0			
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BOILER NO. 13		366 83	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	9.4	LB/H	0.026	LB/MMBTU	CALCULATED	

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TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BOILERS 14 AND 15	PETRO REFIN GAS	586	MMBTU/H EA	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	15.1	LB/H	0.025	LB/MMBTU	EACH, CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BTU- NO 3 REACTOR FEED HEATER		58 95	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	1.5	LB/H	0.025	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BTU-NO.4 REACTOR FEED HEATER		49	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	1.3	LB/H	0.027	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BTU-REFORMATE STABILIZER REBOILER		54.77	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	1.4	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	ISOM II WEST REACTOR FEED HEATER		104 25	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	2.7	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	ISOM II COMBINATION SPLITTER HEATER		77.62	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	2	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	ISOM II XYLENE RERUN TOWER HEATER		83.7	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	2.2	LB/H	0.026	LB/MMBTU	CALCULATED	

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	ISOM II EAST REACTOR FEED HEATER		75	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	1.9	LB/H	0.025	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	ORTHOXYLENE I HEATER		96 23	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR CONTENT FUEL: USE REFINERY FUEL GAS WITH NO MORE THAN 0.1 GR/DSCF H2S OR USE NATURAL GAS WITH NO MORE THAN 0 25 GR/100 DSCF H2S AND NO MORE THAN 5.0 GR/100 DSCF TOTAL S.	2.5	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	ORTHOXYLENE II HEATER		226.42	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR CONTENT FUEL: USE REFINERY FUEL GAS WITH NO MORE THAN 0.1 GR/DSCF H2S OR USE NATURAL GAS WITH NO MORE THAN 0 25 GR/100 DSCF H2S AND NO MORE THAN 5.0 GR/100 DSCF TOTAL S.	5.8	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BACKUP AIR COMPRESSOR ENGINES (1-5)				Sulfur Dioxide (SO2)	LOW SULFUR CONTENT FUEL: USE REFINERY FUEL GAS WITH NO MORE THAN 0.1 GR/DSCF H2S OR USE NATURAL GAS WITH NO MORE THAN 0 25 GR/100 DSCF H2S AND NO MORE THAN 5.0 GR/100 DSCF TOTAL S.	4.72	LB/H	0			
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BTU-NO. 1 REACTOR FEED HEATER		121.74	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	3.1	LB/H	0.025	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BTU-NO.2 REACTOR FEED HEATER		69.68	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	1.8	LB/H	0.025	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BENZENE STABILIZER HEATER	PETRO REFIN GAS	38 34	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	1	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0375	LYONDELL - CITGO REFINING, LP	TX	03/14/2002 EST	BOILER NO. 12		245	MMBTU/H	Sulfur Dioxide (SO2)	LOW S FUEL: FUEL GAS WITH H2S CONTENT NO MORE THAN 0.1 GR/DSCF OVER A 3 H ROLLING BASIS, OR NATURAL GAS WITH H2S CONTENT NO MORE THAN 0.25 GR/100 DSCF AND TOTAL S CONTENT NO MORE THAN 5.0 GR/ 100 DSCF.	6.3	LB/H	0.026	LB/MMBTU	CALCULATED	
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	TX	05/23/2000 ACT	NO. 1 HYDROTREATER REBOILER HEATER	REFINERY GAS	32.7	MMBTU/H	Sulfur Dioxide (SO2)		1.23	LB/H	0			

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TX-0395	DIAMOND SHAMROCK MCKEE PLANT	TX	05/23/2000 ACT	NO. 1 REFORMER CHARGE HEATER	REFINERY GAS	248	MMBTU/H	Sulfur Dioxide (SO2)		9.33	LB/H	0			
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	TX	05/23/2000 ACT	NO. 1 REFORMER STABILIZER REPOILER HEATER	REFINERY GAS	20	MMBTU/H	Sulfur Dioxide (SO2)		0.75	LB/H	0			
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	TX	05/23/2000 ACT	NO 1 INTERHEATER	REFINERY GAS	147.2	MMBTU/H	Sulfur Dioxide (SO2)		5.54	LB/H	0			
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	TX	05/23/2000 ACT	NO. 1 REBOILER STABILIZER REBOILER HEATER	REFINERY GAS	45.7	MMBTU/H	Sulfur Dioxide (SO2)		1.72	LB/H	0			
TX-0395	DIAMOND SHAMROCK MCKEE PLANT	TX	05/23/2000 ACT	NO. 1 HYDROTREATER CHARGE HEATER	REFINERY GAS	63.4	MMBTU/H	Sulfur Dioxide (SO2)		2.39	LB/H	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	SR- 3/4 INCINERATOR				Sulfur Dioxide (SO2)		300	PPMV	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	EAST PROPERTY FLARE				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	COKER FLARE				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	TWENTY ONE FURNACES	REFINERY FUEL GAS			Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	FOURTEEN HEATERS				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	DHT H2 HEATER	HYDROGEN			Sulfur Dioxide (SO2)		300	PPMV	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	CO BOILER	CARBON MONOXIDE			Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	CCU FLARE				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	FOUR TAIL GAS INCINERATORS				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	WEST PROPERTY FLARE				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	THREE FLARES				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	ANALYZER				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	44-H-1 DIESEL HDS HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT THE CONENT OF H2S IN FUEL GAS	0.8	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	44-H-2 DIESEL HDS HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LOWER THE CONTENT OF H2S IN FUEL GAS	0.6	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	7-H-2 DELAYED COKER CHARGE HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	3.2	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	8-H-3 #4 VACUUM CHARGE HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	0.6	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	8-H-4 #4 CRUDE CHARGE HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	4	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	8-H-5 #4 VACUUM CHARGE HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT HS2 CONTENT IN FUEL GAS	0.6	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	8-H-6 #4 CRUDE CHARGE HEATER				Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	5.4	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	H-TK-47,48,54,70,83	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	0.1	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	EP-B-1 & EP-B-2 COMPLEX 8 #1&2	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S IN THE FUEL GAS	4	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	B-4, B-5 COMPLEX 6 WEST & EAST BOILER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	4.1	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	EP-B-5 COMPLEX 8 BOILER #5	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S IN FUEL GAS	7.8	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	12-H-1 FCCU RAW OIL CHARGE HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	2	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	17-H-1 ALKY. ISO. STRIPPER REBOILER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	0.5	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	27-H-1 KTX. CLAR TWR. CHARGE HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S IN FUEL GAS	0.3	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	27-H-2 TETRAMER SPL. REB. HTR.	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S IN FUEL GAS	0.2	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	37-H-1 KERO. HDS CHARGE HEATER, 38-H-2KEROSENE HDS HEATER, 39-H-1 #4 HC CHARGE HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S IN FUEL GAS	0.8	LB/H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Gaseous Fuel < 100 million BTU/hr

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	37-H-2 KERO HDS FRAC REBOILER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	0.3	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	38-H-1 KEROSENE HDS CHARGE HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	0.7	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	39-H-2 #4 HC STRIPPER REBOILER				Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	0.7	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	39-H-7	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	1.4	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	Q3-H-4A/B	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	1.1	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	Q3-H-3 #2 REFORMER HDS CHARGER AND STRIPPER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	0.9	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	Q10-H-1 SMR HEATER	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	7.2	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	Q11-H-301 HCU RX CHARGE	FUEL GAS			Sulfur Dioxide (SO2)		1.5	LB/H	0			
TX-0443	VALERO CORPUS CHRISTI REFINERY EAST PLANT	TX	01/01/2005 ACT	Q3-H-3 FRACTIONATOR AND Q11-H-3001,3002 HCU DEBUT. REB. AND FRACT. REB.	FUEL GAS			Sulfur Dioxide (SO2)	LIMIT H2S CONTENT IN FUEL GAS	0.7	LB/H	0			
TX-0472	FLINT HILLS RESOURCES CORPUS CHRISTI WEST PLANT	TX	01/24/2005 ACT	New Boilers, Flint Hills West Refinery	Natural Gas and refinery fuel gas	0		Sulfur Dioxide (SO2)		100	% COMB CONV TO SO2	0			SO2 emissions are estimated using the maximum and average H2S content in the fuel gas and assuming 100% combustion conversion to SO2. The short-term maximum H2S content is 162 ppmv on a 3-hour rolling average in accordance with NSPS Subpart J. The average H2S content is 81 ppmv on a 365-day rolling average.
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	BSI Heater	Refinery Fuel Gas	50	MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0			
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	Emergency Air Compressor	Ultra Low Sulfur Diesel	400	hp	Sulfur Dioxide (SO2)	Ultra Low Sulfur Diesel	0		0			
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	581 Crude Heater	Refinery Fuel Gas	233	MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0			
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	583 Vacuum Heater	Refinery Fuel Gas	64.2	MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0			
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	Naphtha Splitter Heater	Refinery Fuel Gas	46.3	MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0			
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	Hydrocracker H5 Heater	Refinery Fuel Gas	44.9	MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0			
*WY-0071	SINCLAIR REFINERY	WY	10/15/2012 ACT	#1 HDS Heater	Refinery Fuel Gas	33.4	MMBtu/hr	Sulfur Dioxide (SO2)	Follow Subpart Ja Fuel gas H2S limits	0		0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Chemical Plant Flares

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007 ACT	EMERGENCY DIESEL FIRE WATER PUMP S110 (07-A-982P)		300	BHP	Sulfur Dioxide (SO2)	NONE	0 203	G/KW-H	0			BACT EQUIVALENT TO 0.203 G/KWH
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007 ACT	THERMAL OXIDIZER FOR HRSG FROM DRYERS AND GASIFICATION - TWO SYSTEMS, S10 AND S11 (07-A-955P AND 07-A-956P)	SYNGAS	250	MMBTU/H	Sulfur Dioxide (SO2)	H2S REMOVAL SYSTEM AFTER THE GASIFICATION PROCESS AND PRIOR TO THE USE IN THE DRYERS OR THERMAL OXIDIZERS	0 034	LB/MMBTU	0.2	LB/MMBTU	30-DAY ROLLING, NSPS	FOR THE SYN-GAS MADE FROM COAL, THE SO2 IS LIMITED TO 0.014 LB / MM BTU AND THE SO2 FROM THE PROCESS IS LIMITED TO 0.02 LB / MM BTU EACH BASED ON 250 MM BTU / HR HEAT INPUT.
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007 ACT	BIOMETHANATOR FLARE, EP11 (07-A-957P)	METHANE / SYNGAS / NATURAL GAS	6.4	MM BTU / H	Sulfur Dioxide (SO2)		0.0007	LB/MMBTU	0			
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007 ACT	PRODUCT LOADOUT FOR TRUCKS AND RAIL CARS, EP22 AND F50 (07-A-965P)		1500	GAL/MIN	Sulfur Dioxide (SO2)	FLARE	0.0006	LB/MM BTU	0			
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007 ACT	STARTUP AND SHUTDOWN FLARES 1, 2, AND 3, EP33A, EP33B, AND EP33C (07-A-967P, 07-A-968P, AND 07-A-969P)	NATURAL GAS OR SYNGAS	25	MMBTU	Sulfur Dioxide (SO2)	FLARE	0 395	LB/MM BTU	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 FILTER FUGITIVES	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%	0	LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 DRYER FUGITIVES	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%	0	LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 PROCESS FUGITIVES	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%	0	LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 3 PROCESS FILTER (LIMITS BEFORE UNIT 5)	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%.	4.6	LB/H	0			EMISSION LIMITS BEFORE INSTALLATION OF UNIT 5
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 3 PROCESS FILTER (AFTER UNIT 5 IS INSTALLED)	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%	4.6	LB/H	0			EMISSION LIMITS AFTER INSTALLATION OF UNIT 5
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 3 PELLET DRYER PURGE GAS FILTER	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	BAG FILTER	9.4	LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNITS 1&2 FLARE	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	LIMITATION OF SULFUR CONTENT IN FEEDSTOCK OIL TO 4%	2555.8	LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 3 FLARE	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL LIMITED TO 4%.	2295.1	LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 REACTOR FUGITIVES	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%	0	LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 REACTOR WARM UP VENT	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%.	0.01	LB/H	0			
TX-0277	BASF CORPORATION	TX	12/12/2001 ACT	ACRYLIC ACID INCINERATOR (POINT NO. IN-701)	NATURAL GAS			Sulfur Dioxide (SO2)	NATURAL GAS AS SUPPLEMENTAL FUEL CAN CONTAIN NO MORE THAN 0.5 GR/100 DSCF HYDROGEN SULFIDE AND NO MORE THAN 20 GR/100 DSCF OF SULFER.	20	LB/H	0			COMPLIANCE WITH ANNUAL EMISSION LIMITS IS BASED ON A ROLLING 12-MONTH PERIOD. BASED ON A MAXIMUM OPERATING SCHEDULE OF 8,760 H/YR.
TX-0277	BASF CORPORATION	TX	12/12/2001 ACT	INCINERATOR (POINT NO. IN-5500)	NATURAL GAS			Sulfur Oxides (SOx)	NATURAL GAS AS SUPPLEMENTAL FUEL CAN CONTAIN NO MORE THAN 0.5 GR/100 DSCF HYDROGEN SULFIDE AND NO MORE THAN 20 GR/100 DSCF SULFER.	60.17	LB/H	0			COMPLIANCE WITH ANNUAL EMISSION LIMITS IS BASED ON A ROLLING 12-MONTH PERIOD. BASED ON A MAXIMUM OPERATING SCHEDULE OF 8,760 H/YR.
TX-0277	BASF CORPORATION	TX	12/12/2001 ACT	CONTINUOUS FLARE (POINT NO. 4-2 4)	NATURAL GAS			Sulfur Dioxide (SO2)		0.01	LB/H	0			COMPLIANCE WITH ANNUAL EMISSION LIMITS IS BASED ON A ROLLING 12-MONTH PERIOD. EMISSION RATES ARE BASED ON A MAXIMUM OPERATING SCHEDULE OF 8760 H/YR.
TX-0309	FORMOSA PLASTICS TEXAS	TX	02/10/2000 ACT	(2) STARTUP HEATERS, 70H101-1&-2		75	MMBTU/H, EA	Sulfur Dioxide (SO2)	NONE INDICATED	0.04	LB/H	0.0005	LB/MMBTU	CALCULATED FROM HOURLY E.L. AND THRUPUT	
TX-0309	FORMOSA PLASTICS TEXAS	TX	02/10/2000 ACT	PROCESS FUGITIVES, 70ANFUG				Sulfur Dioxide (SO2)	NONE INDICATED	0.46	LB/H	0			FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED AS A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0309	FORMOSA PLASTICS TEXAS	TX	02/10/2000 ACT	WASTE HEAT BOILER, 70Z401	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.26	LB/H	0			
TX-0309	FORMOSA PLASTICS TEXAS	TX	02/10/2000 ACT	PROCESS FLARE, 70Z522				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Chemical Plant Flares

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	FIREWATER PUMP, 81				Sulfur Dioxide (SO2)	NONE INDICATED	0.26	LB/H	0			
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	SOLAR TURBINE & DUCT BURNER, 70	NATURAL GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.28	LB/H	0			
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	CONTINUOUS CATALYST REGENERATOR, 71				Sulfur Dioxide (SO2)	CAUSTIC SCRUBBER	0.12	LB/H	0			
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	REACTOR HEATER, 72	FUEL GAS			Sulfur Dioxide (SO2)	FIRING NAT GAS	0.38	LB/H	0		NOT AVAILABLE	
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	3 DIP TURBINES & 3 DUCT BURNERS, 74	NAT GAS			Sulfur Dioxide (SO2)	FIRING NAT GAS WITH S CONCENTRATION OF NO MORE THAN 15 PPMW.	0.46	LB/H	0			
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	FLARE, 76				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	2ND STAGE HYDROTREATER FEED HEATER, J-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.08	LB/H	0		NOT AVAILABLE	
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	(2) HYDROTREATER REGENERATOR STACKS,DD-606&DDD-606				Sulfur Dioxide (SO2)	NONE INDICATED	45.8	LB/H	0			
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	NO. 1 OLEFINS FLARE, DM-1101				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	NO. 2 OLEFINS FLARE, DDM-3101				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	REGENERATION FURNACE, DB-201				Sulfur Dioxide (SO2)	NONE INDICATED	0.52	LB/H	0		NOT AVAILABLE	
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	REGENERATION HEATER, DB-601				Sulfur Dioxide (SO2)	NONE INDICATED	0.07	LB/H	0		NOT AVAILABLE	
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	REGENERATION HEATER, DDB-201				Sulfur Dioxide (SO2)	NONE INDICATED	0.5	LB/H	0		NOT AVAILABLE	
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	REGENERATION HEATER, DDB-601				Sulfur Dioxide (SO2)	NONE INDICATED	0.07	LB/H	0		NOT AVAILABLE	
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	FURNACE EMISSION CAPS FOR 30 EMISSION POINTS				Sulfur Dioxide (SO2)	NONE INDICATED	48	LB/H	0			ADDITIONAL CAPS: 53.66 LB/H, 11.75 T/YR FROM 3/31/04 TO 6/30/06, 61 37 LB/H, 13.44 T/YR AFTER 6/30/06
TX-0353	NAFTA REGION OLEFINS COMPLEX	TX	09/05/2001 ACT	BOILER, BLR	NAT GAS			Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMIT: THE NATURAL GAS STREAM SHALL CONTAIN LESS THAN 5 GR TOTAL SULFUR/100 DSCF.	3.25	LB/H	0		NOT AVAILABLE	
TX-0353	NAFTA REGION OLEFINS COMPLEX	TX	09/05/2001 ACT	HIGH PRESSURE FLARE, P-7	NAT GAS/ WASTE			Sulfur Dioxide (SO2)	NONE INDICATED	14.13	LB/H	0			
TX-0353	NAFTA REGION OLEFINS COMPLEX	TX	09/05/2001 ACT	LOW PRESSURE FLARE, P-6	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TRAIN 1- ETSH OR TBM PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TRAIN 1 - MESH PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES FOR LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TRAIN 2- MESH PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SULFUR TRUCK, S-3				Sulfur Dioxide (SO2)	NONE INDICATED	0.07	LB/H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Chemical Plant Flares

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TANK TRUCK LOADING/UNLOADING FUGITIVES				Sulfur, Total Reduced (TRS)	SEE POLLUTANT NOTES. FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.03	LB/H	0			ALL LOADING LINES SHALL BE INSPECTED VISUALLY FOR POSSIBLE LEAK SITES BEFORE THE START OF ANY LOADING OPERATIONS. DAMAGED HOSES SHALL BE REPAIRED OR REPLACED BEFORE ANY LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADING OPERATIONS, ALL LOADING LINES (EXCEPT FOR MMP) SHALL BE PURGED WITH INERT GAS TO THE FLARE BEFORE ANY CONNECTIONS BETWEEN THE LOADING RACKS AND LOADED VESSELS ARE BROKEN. MMP RAILCAR LOADING WILL USE CLOSED LOOP VAPOR BALANCE SYSTEMS CONNECTED TO THE MMP STORAGE TANK OR THE SULFOX-TO. UPON COMPLETION OF MMP LOADING OPERATIONS THE LOADING LINE WILL BE PURGED INTO THE RAILCAR OR THE MMP STORAGE TANK. WHEN UNHOOKING THE RAILCAR FROM THE LOADING LINE, AN ACETIC ACID OR EQUIVALENT WASH WILL BE DONE AFTER EACH MMP LOADING. THE WASH MATERIAL WILL BE NEUTRALIZED AND MANAGED IN THE ON-SITE WASTEWATER SYSTEM. THE WASH MATERIAL TANK WILL VENT TO THE SULFOX-TO.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, SSM				Sulfur, Total Reduced (TRS)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18	24.27	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, SSM				Sulfur Dioxide (SO2)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18. SEE THE POLLUTANT NOTES.	2541.37	LB/H	0			TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW 5193 LB/H.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, TOTAL HOURLY AND ANNUAL				Sulfur, Total Reduced (TRS)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18	65.62	LB/H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Chemical Plant Flares

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, TOTAL HOURLY AND ANNUAL				Sulfur Dioxide (SO2)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18. SEE POLLUTANT NOTES.	6207.34	LB/H	0			TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW 5193 LB/H.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	HEAT TRANSFER FLUID HEATER, H202	NATURAL GAS	31	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.02	LB/H	0.0006	LB/MMBTU	CALCULATED, USING THROUGHPUT	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	(2) SULFUR/METHANE HEATERS				Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.01	LB/H	0		NOT AVAILABLE	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	HEAT TRANSFER FLUID HEATER, H2202	NATURAL GAS	31	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 0.5 GR S/100 DSCF.	0.02	LB/H	0.0006	LB/MMBTU	CALCULATED USING THROUGHPUT	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	INCINERATOR				Sulfur Dioxide (SO2)	NONE INDICATED	139	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SULFUR STORAGE TANK, S-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.86	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SULFUR PIT, S-2				Sulfur Dioxide (SO2)	NONE INDICATED	0.17	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SOUR WATER STRIPPERS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, SSM		134.5	MMBTU/H	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, SSM		134.5	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	1156.47	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, TOTAL HOURLY AND ANNUAL		134.5	MMBTU/H	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, TOTAL HOURLY AND ANNUAL		134.5	MMBTU/H	Sulfur Dioxide (SO2)	THE FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	1157.44	LB/H	0			WASTE GAS AND ATOMIZED LIQUID STREAMS FROM THE SULFOX UNITS SHALL BE ROUTED TO THE SULFOX TO. THE SULFOX TO SHALL DESTROY THE VOC STREAMS SENT TO IT AT A MINIMUM OF 99.9% OR AT A VOC OUTLET CONCENTRATION OF 10 PPMV.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, STEADY STATE OPERATION				Sulfur, Total Reduced (TRS)	FOLLOW REQUIREMENTS OF 40 CFR 60.18	41.35	LB/H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Chemical Plant Flares

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, STEADY STATE OPERATION				Sulfur Dioxide (SO2)	FOLLOW SPECIFICATIONS OF 40 CFR 60.18. SEE POLLUTANT NOTES.	3665.97	LB/H	0			TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW 5193 LB/H.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	PRODUCT RECOVERY TOWER FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	RAILCAR LOADING/UNLOADING FUGITIVES				Sulfur, Total Reduced (TRS)	SEE POLLUTANT NOTES.	0.03	LB/H	0			ALL LOADING LINES SHALL BE INSPECTED VISUALLY FOR POSSIBLE LEAK SITES BEFORE THE START OF ANY LOADING OPERATIONS. DAMAGED HOSES SHALL BE REPAIRED OR REPLACED BEFORE ANY LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADING OPERATIONS, ALL LOADING LINES (EXCEPT FOR MMP) SHALL BE PURGED WITH INERT GAS TO THE FLARE BEFORE ANY CONNECTIONS BETWEEN THE LOADING RACKS AND LOADED VESSELS ARE BROKEN. MMP RAILCAR LOADING WILL USE CLOSED LOOP VAPOR BALANCE SYSTEMS CONNECTED TO THE MMP STORAGE TANK OR THE SULFOX-TO. UPON COMPLETION OF MMP LOADING OPERATIONS THE LOADING LINE WILL BE PURGED INTO THE RAILCAR OR THE MMP STORAGE TANK. WHEN UNHOOKING THE RAILCAR FROM THE LOADING LINE, AN ACETIC ACID OR EQUIVALENT WASH WILL BE DONE AFTER EACH MMP LOADING. THE WASH MATERIAL WILL BE NEUTRALIZED AND MANAGED IN THE ON-SITE WASTEWATER SYSTEM. THE WASH MATERIAL TANK WILL VENT TO THE SULFOX-TO.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	DIMETHYL DISULFIDE AREA PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.06	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	(2) STEAM BOILERS, X-426A AND X-426B	NATURAL GAS	15.8	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.01	LB/H	0.0006	LB/MMBTU	EACH, CALCULATED USING THROUGHPUT	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	RUNDOWN TANK FUGITIVES				Sulfur, Total Reduced (TRS)	MMP DAY STORAGE TANKS WILL VENT TO THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULF0X-TO. FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.11	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	STORAGE TANKS FUGITIVES				Sulfur, Total Reduced (TRS)	MMP DAY STORAGE TANKS WILL VENT TO THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULF0X-TO. FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.15	LB/H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Chemical Plant Flares

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	DIMETHYL SULFIDE AREA PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	H2S PLANT PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, STEADY STATE SERVICE		134.5	MMBTU/H	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, STEADY STATE SERVICE		134.5	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS COMBUSTED IN EACH COMBUSTION EMISSION POINT NUMBER SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	4.21	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	PACKAGE BOILER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE	
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	STANDBY INCINERATOR				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	PACKAGE BOILER BO-4	NAT GAS	60	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.95	LB/H	0 02	LB/MMBTU	CALCULATED USING THROUGHPUT	
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	REGENERATIVE GAS HEATER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE	
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	MONUMENT NO. 2 FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	WASTE HEAT BOILER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE	
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	TRAIN NO. 8 FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	ALKYL FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0380	SYNTHESIS GAS UNIT	TX	06/01/2001 ACT	(2) AIR PREHEATERS 1106 & 1206, F1106SGU &F1206SGU				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE	
TX-0380	SYNTHESIS GAS UNIT	TX	06/01/2001 ACT	FLARE, FS28	SYNGAS			Sulfur Dioxide (SO2)	NONE INDICATED	3337.57	LB/H	0			
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	TX	12/05/2002 ACT	HEATER, STARTUP, MALEIC ANHYDRIDE REACTOR	NATURAL GAS	160.7	mmbtu/h	Sulfur Dioxide (SO2)	PIPELINE QUALITY NATURAL GAS < 2.0 GR S PER 1000 DSCF	0.64	LB/H	0.004	LB/MMBTU	CALCULATED	
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	TX	12/05/2002 ACT	FLARE, BDO UNIT	NATURAL GAS			Sulfur Dioxide (SO2)		0.05	LB/H	0			
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	TX	12/05/2002 ACT	BOILER, SCRUBBER OFF-GAS				Sulfur Oxides (SOx)		7.75	LB/H	0		SEE NOTE	STANDARDIZED EMISSION LIMIT UNAVAILABLE.
TX-0449	UCC SEADRIFT OPERATIONS	TX	04/03/2004 ACT	FLARE BEFOER THE RECYCLE COMPRESSOR PROJECTS IS COMPLETE				Sulfur Dioxide (SO2)	MEETS HEATING VALUES AND VELOCITY REQ. AND BTU ANALYZERS	1.38	LB/H	0			
TX-0449	UCC SEADRIFT OPERATIONS	TX	04/03/2004 ACT	FLARE AFTER THE RECYCLE COMPRESSOR PROJECTS IS COMPLETE				Sulfur Dioxide (SO2)	MEETS HEATING VALUES AND VELOCITY REQ. AND BTU ANALYZERS	1.38	LB/H	0			
TX-0449	UCC SEADRIFT OPERATIONS	TX	04/03/2004 ACT	FLARE NATURAL GAS COMBUSTION (6)	NATURAL GAS			Sulfur Dioxide (SO2)	MEETS HEATING VALUES AND VELOCITY REQ. AND BTU ANALYZERS	0.5	LB/H	0			
TX-0449	UCC SEADRIFT OPERATIONS	TX	04/03/2004 ACT	STARTUP, SHUTDOWN, MAINTENANCE BEFORE THE RECYCLE PROJECT IS COMPLETE (5)				Sulfur Dioxide (SO2)	GOOD PRACTICES	1.38	LB/H	0			
TX-0449	UCC SEADRIFT OPERATIONS	TX	04/03/2004 ACT	STARTUP, SHUTDOWN, MAINTENANCE AFTER THE RECYCLE PROJECT IS COMPLETE (5)				Sulfur Dioxide (SO2)	GOOD PRACTICES	1.38	LB/H	0			
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	TX	03/18/2005 ACT	PILOT PLANT FLARE				Sulfur Dioxide (SO2)		435.27	LB/H	0			
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	TX	03/18/2005 ACT	PROCESS BAG FILTER				Sulfur Dioxide (SO2)		0.15	LB/H	0			
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	TX	03/18/2005 ACT	FEED STOCK OIL PRE HEATER	NATURAL GAS, FUEL OIL, OR FLUE GAS	0.9	MMBTU/H	Sulfur Dioxide (SO2)		0 001	LB/H	0			
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	TX	03/18/2005 ACT	OXYGEN PRE HEATER	NATURAL GAS			Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	COOPER-BESSEMER ENGINE 3105 HP		3105	HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.26	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	HOT OIL HEATER		32.5	MMBTU/H	Sulfur Dioxide (SO2)		0.02	LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	FLARES (2)				Sulfur Dioxide (SO2)		50.48	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	HP TEG FIREBOX				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	COOPER-BESSEMER ENGINE		2400	HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.36	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	CLARK ENGINE (2)		2000	HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.31	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	INGERSOLL-RAND ENGINE		440	HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.7	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	HOT OIL HEATER		12	MMBTU/H	Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	INGERSOLL-RAND ENGINE 1330 HP		1330	HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.33	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	GLYCOL REBOILER		2.5	MMBUT/H	Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	DHT STRIPPER REBOILER	REFINERY FUEL GAS			Sulfur Dioxide (SO2)		1.9	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	COKER HEATER		291	MMBUT/H	Sulfur Dioxide (SO2)		6.6	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER		62	MMBTU/H	Sulfur Dioxide (SO2)		1.4	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	ACID GAS FLARE				Sulfur Dioxide (SO2)		0.2	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	NO.3 BOILER	REFINERY FUEL GAS	99	MMBTU/H	Sulfur Dioxide (SO2)		2.2	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	TAIL GAS INCINERATOR		100	MMBTU/H	Sulfur Dioxide (SO2)		22.4	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER REBOILER HEATER	REFINERY FUEL GAS	82	MMBTU/H	Sulfur Dioxide (SO2)		5.7	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	SOUR WATER STRIPPER FLARE				Sulfur Dioxide (SO2)		0.19	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	FLARE-COKE DRUM BLOWDOWN				Sulfur Dioxide (SO2)		1056	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	DHT CHARGER HEATER				Sulfur Dioxide (SO2)		2.1	LB/H	0			
TX-0481	AIR PRODUCTS BAYTOWN I I	TX	11/02/2004 ACT	BOILER STACK	NATURAL GAS			Sulfur Dioxide (SO2)		24.2	LB/H	0			
TX-0481	AIR PRODUCTS BAYTOWN I I	TX	11/02/2004 ACT	EMERGENCY GENERATOR				Sulfur Dioxide (SO2)		4.8	LB/H	0			
TX-0481	AIR PRODUCTS BAYTOWN I I	TX	11/02/2004 ACT	FLARE (NORMAL OPERATION)	NATURAL GAS			Sulfur Dioxide (SO2)		0.04	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	L-AREA GAS TURBINE	NATURAL GAS			Sulfur Dioxide (SO2)		0.03	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N5/6 FLARE				Sulfur Dioxide (SO2)		0.11	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N-3 BACKUP INSTRUMENT AIR COMPRESSOR				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N7/8 PREHEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N3/7 FEED AND EXIT GAS FLARE				Sulfur Dioxide (SO2)		0.11	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N-3,4 PREHEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N-5/6 PREHEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0514	ENTERPRISE MONT BELVIEU COMPLEX	TX	01/24/2006 ACT	FLARE-NORMAL OPERATION				Sulfur Dioxide (SO2)		1.1	LB/H	0			
TX-0526	AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	TX	08/18/2006 EST	FLARE PILOTS ONLY				Sulfur Dioxide (SO2)		0 002	LB/H	0			
TX-0526	AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	TX	08/18/2006 EST	FLARE-MSS				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0526	AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	TX	08/18/2006 EST	GAS TURBINE STACK	NATURAL GAS	700	MMBTU/H	Sulfur Dioxide (SO2)		0.92	LB/H	0			
TX-0526	AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	TX	08/18/2006 EST	REFORMER FURNACE STACK	STEAM	1373	MMBTU/H	Sulfur Dioxide (SO2)		7.3	LB/H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Other Flares

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007 ACT	EMERGENCY DIESEL FIRE WATER PUMP S110 (07-A-982P)		300	BHP	Sulfur Dioxide (SO2)	NONE	0 203	G/KW-H	0			BACT EQUIVALENT TO 0.203 G/KWH
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007 ACT	THERMAL OXIDIZER FOR HRSG FROM DRYERS AND GASIFICATION - TWO SYSTEMS, S10 AND S11 (07-A-955P AND 07-A-956P)	SYNGAS	250	MMBTU/H	Sulfur Dioxide (SO2)	H2S REMOVAL SYSTEM AFTER THE GASIFICATION PROCESS AND PRIOR TO THE USE IN THE DRYERS OR THERMAL OXIDIZERS	0 034	LB/MMBTU	0.2	LB/MMBTU	30-DAY ROLLING, NSPS	FOR THE SYN-GAS MADE FROM COAL, THE SO2 IS LIMITED TO 0.014 LB / MM BTU AND THE SO2 FROM THE PROCESS IS LIMITED TO 0.02 LB / MM BTU EACH BASED ON 250 MM BTU / HR HEAT INPUT.
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007 ACT	BIOMETHANATOR FLARE, EP11 (07-A-957P)	METHANE / SYNGAS / NATURAL GAS	6.4	MM BTU / H	Sulfur Dioxide (SO2)		0.0007	LB/MMBTU	0			
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007 ACT	PRODUCT LOADOUT FOR TRUCKS AND RAIL CARS, EP22 AND F50 (07-A-965P)		1500	GAL/MIN	Sulfur Dioxide (SO2)	FLARE	0.0006	LB/MM BTU	0			
IA-0089	HOMELAND ENERGY SOLUTIONS, LLC, PN 06-672	IA	08/08/2007 ACT	STARTUP AND SHUTDOWN FLARES 1, 2, AND 3, EP33A, EP33B, AND EP33C (07-A-967P, 07-A-968P, AND 07-A-969P)	NATURAL GAS OR SYNGAS	25	MMBTU	Sulfur Dioxide (SO2)	FLARE	0 395	LB/MM BTU	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 FILTER FUGITIVES	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%	0	LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 DRYER FUGITIVES	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%	0	LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 PROCESS FUGITIVES	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%	0	LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 3 PROCESS FILTER (LIMITS BEFORE UNIT 5)	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%.	4.6	LB/H	0			EMISSION LIMITS BEFORE INSTALLATION OF UNIT 5
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 3 PROCESS FILTER (AFTER UNIT 5 IS INSTALLED)	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%	4.6	LB/H	0			EMISSION LIMITS AFTER INSTALLATION OF UNIT 5
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 3 PELLET DRYER PURGE GAS FILTER	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	BAG FILTER	9.4	LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNITS 1&2 FLARE	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	LIMITATION OF SULFUR CONTENT IN FEEDSTOCK OIL TO 4%	2555.8	LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 3 FLARE	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL LIMITED TO 4%.	2295.1	LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 REACTOR FUGITIVES	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%	0	LB/H	0			
LA-0163	CABOT CORPORATION- VILLE PLATTE	LA	11/04/1999 ACT	UNIT 4 REACTOR WARM UP VENT	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK OIL IS LIMITED TO 4%.	0.01	LB/H	0			
TX-0277	BASF CORPORATION	TX	12/12/2001 ACT	ACRYLIC ACID INCINERATOR (POINT NO. IN-701)	NATURAL GAS			Sulfur Dioxide (SO2)	NATURAL GAS AS SUPPLEMENTAL FUEL CAN CONTAIN NO MORE THAN 0.5 GR/100 DSCF HYDROGEN SULFIDE AND NO MORE THAN 20 GR/100 DSCF OF SULFER.	20	LB/H	0			COMPLIANCE WITH ANNUAL EMISSION LIMITS IS BASED ON A ROLLING 12-MONTH PERIOD. BASED ON A MAXIMUM OPERATING SCHEDULE OF 8,760 H/YR.
TX-0277	BASF CORPORATION	TX	12/12/2001 ACT	INCINERATOR (POINT NO. IN-5500)	NATURAL GAS			Sulfur Oxides (SOx)	NATURAL GAS AS SUPPLEMENTAL FUEL CAN CONTAIN NO MORE THAN 0.5 GR/100 DSCF HYDROGEN SULFIDE AND NO MORE THAN 20 GR/100 DSCF SULFER.	60.17	LB/H	0			COMPLIANCE WITH ANNUAL EMISSION LIMITS IS BASED ON A ROLLING 12-MONTH PERIOD. BASED ON A MAXIMUM OPERATING SCHEDULE OF 8,760 H/YR.
TX-0277	BASF CORPORATION	TX	12/12/2001 ACT	CONTINUOUS FLARE (POINT NO. 4-2 4)	NATURAL GAS			Sulfur Dioxide (SO2)		0.01	LB/H	0			COMPLIANCE WITH ANNUAL EMISSION LIMITS IS BASED ON A ROLLING 12-MONTH PERIOD. EMISSION RATES ARE BASED ON A MAXIMUM OPERATING SCHEDULE OF 8760 H/YR.
TX-0309	FORMOSA PLASTICS TEXAS	TX	02/10/2000 ACT	(2) STARTUP HEATERS, 70H101-1&-2		75	MMBTU/H, EA	Sulfur Dioxide (SO2)	NONE INDICATED	0.04	LB/H	0.0005	LB/MMBTU	CALCULATED FROM HOURLY E.L. AND THRUPUT	
TX-0309	FORMOSA PLASTICS TEXAS	TX	02/10/2000 ACT	PROCESS FUGITIVES, 70ANFUG				Sulfur Dioxide (SO2)	NONE INDICATED	0.46	LB/H	0			FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED AS A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0309	FORMOSA PLASTICS TEXAS	TX	02/10/2000 ACT	WASTE HEAT BOILER, 70Z401	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.26	LB/H	0			
TX-0309	FORMOSA PLASTICS TEXAS	TX	02/10/2000 ACT	PROCESS FLARE, 70Z522				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	FIREWATER PUMP, 81				Sulfur Dioxide (SO2)	NONE INDICATED	0.26	LB/H	0			
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	SOLAR TURBINE & DUCT BURNER, 70	NATURAL GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.28	LB/H	0			
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	CONTINUOUS CATALYST REGENERATOR, 71				Sulfur Dioxide (SO2)	CAUSTIC SCRUBBER	0.12	LB/H	0			
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	REACTOR HEATER, 72	FUEL GAS			Sulfur Dioxide (SO2)	FIRING NAT GAS	0.38	LB/H	0		NOT AVAILABLE	
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	3 DIP TURBINES & 3 DUCT BURNERS, 74	NAT GAS			Sulfur Dioxide (SO2)	FIRING NAT GAS WITH S CONCENTRATION OF NO MORE THAN 15 PPMW.	0.46	LB/H	0			
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	FLARE, 76				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	2ND STAGE HYDROTREATER FEED HEATER, J-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.08	LB/H	0		NOT AVAILABLE	
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	(2) HYDROTREATER REGENERATOR STACKS,DD-606&DDD-606				Sulfur Dioxide (SO2)	NONE INDICATED	45.8	LB/H	0			
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	NO. 1 OLEFINS FLARE, DM-1101				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	NO. 2 OLEFINS FLARE, DDM-3101				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	REGENERATION FURNACE, DB-201				Sulfur Dioxide (SO2)	NONE INDICATED	0.52	LB/H	0		NOT AVAILABLE	
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	REGENERATION HEATER, DB-601				Sulfur Dioxide (SO2)	NONE INDICATED	0.07	LB/H	0		NOT AVAILABLE	
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	REGENERATION HEATER, DDB-201				Sulfur Dioxide (SO2)	NONE INDICATED	0.5	LB/H	0		NOT AVAILABLE	
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	REGENERATION HEATER, DDB-601				Sulfur Dioxide (SO2)	NONE INDICATED	0.07	LB/H	0		NOT AVAILABLE	
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	FURNACE EMISSION CAPS FOR 30 EMISSION POINTS				Sulfur Dioxide (SO2)	NONE INDICATED	48	LB/H	0			ADDITIONAL CAPS: 53.66 LB/H, 11.75 T/YR FROM 3/31/04 TO 6/30/06, 61 37 LB/H, 13.44 T/YR AFTER 6/30/06
TX-0353	NAFTA REGION OLEFINS COMPLEX	TX	09/05/2001 ACT	BOILER, BLR	NAT GAS			Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMIT: THE NATURAL GAS STREAM SHALL CONTAIN LESS THAN 5 GR TOTAL SULFUR/100 DSCF.	3.25	LB/H	0		NOT AVAILABLE	
TX-0353	NAFTA REGION OLEFINS COMPLEX	TX	09/05/2001 ACT	HIGH PRESSURE FLARE, P-7	NAT GAS/ WASTE			Sulfur Dioxide (SO2)	NONE INDICATED	14.13	LB/H	0			
TX-0353	NAFTA REGION OLEFINS COMPLEX	TX	09/05/2001 ACT	LOW PRESSURE FLARE, P-6	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TRAIN 1- ETSH OR TBM PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TRAIN 1 - MESH PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES FOR LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TRAIN 2- MESH PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SULFUR TRUCK, S-3				Sulfur Dioxide (SO2)	NONE INDICATED	0.07	LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TANK TRUCK LOADING/UNLOADING FUGITIVES				Sulfur, Total Reduced (TRS)	SEE POLLUTANT NOTES. FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.03	LB/H	0			ALL LOADING LINES SHALL BE INSPECTED VISUALLY FOR POSSIBLE LEAK SITES BEFORE THE START OF ANY LOADING OPERATIONS. DAMAGED HOSES SHALL BE REPAIRED OR REPLACED BEFORE ANY LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADING OPERATIONS, ALL LOADING LINES (EXCEPT FOR MMP) SHALL BE PURGED WITH INERT GAS TO THE FLARE BEFORE ANY CONNECTIONS BETWEEN THE LOADING RACKS AND LOADED VESSELS ARE BROKEN. MMP RAILCAR LOADING WILL USE CLOSED LOOP VAPOR BALANCE SYSTEMS CONNECTED TO THE MMP STORAGE TANK OR THE SULFOX-TO. UPON COMPLETION OF MMP LOADING OPERATIONS THE LOADING LINE WILL BE PURGED INTO THE RAILCAR OR THE MMP STORAGE TANK. WHEN UNHOOKING THE RAILCAR FROM THE LOADING LINE, AN ACETIC ACID OR EQUIVALENT WASH WILL BE DONE AFTER EACH MMP LOADING. THE WASH MATERIAL WILL BE NEUTRALIZED AND MANAGED IN THE ON-SITE WASTEWATER SYSTEM. THE WASH MATERIAL TANK WILL VENT TO THE SULFOX-TO.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, SSM				Sulfur, Total Reduced (TRS)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18	24.27	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, SSM				Sulfur Dioxide (SO2)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18. SEE THE POLLUTANT NOTES.	2541.37	LB/H	0			TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW 5193 LB/H.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, TOTAL HOURLY AND ANNUAL				Sulfur, Total Reduced (TRS)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18	65.62	LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, TOTAL HOURLY AND ANNUAL				Sulfur Dioxide (SO2)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18. SEE POLLUTANT NOTES.	6207.34	LB/H	0			TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW 5193 LB/H.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	HEAT TRANSFER FLUID HEATER, H202	NATURAL GAS	31	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.02	LB/H	0.0006	LB/MMBTU	CALCULATED, USING THROUGHPUT	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	(2) SULFUR/METHANE HEATERS				Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.01	LB/H	0		NOT AVAILABLE	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	HEAT TRANSFER FLUID HEATER, H2202	NATURAL GAS	31	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 0.5 GR S/100 DSCF.	0.02	LB/H	0.0006	LB/MMBTU	CALCULATED USING THROUGHPUT	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	INCINERATOR				Sulfur Dioxide (SO2)	NONE INDICATED	139	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SULFUR STORAGE TANK, S-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.86	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SULFUR PIT, S-2				Sulfur Dioxide (SO2)	NONE INDICATED	0.17	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SOUR WATER STRIPPERS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, SSM		134.5	MMBTU/H	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, SSM		134.5	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	1156.47	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, TOTAL HOURLY AND ANNUAL		134.5	MMBTU/H	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, TOTAL HOURLY AND ANNUAL		134.5	MMBTU/H	Sulfur Dioxide (SO2)	THE FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	1157.44	LB/H	0			WASTE GAS AND ATOMIZED LIQUID STREAMS FROM THE SULFOX UNITS SHALL BE ROUTED TO THE SULFOX TO. THE SULFOX TO SHALL DESTROY THE VOC STREAMS SENT TO IT AT A MINIMUM OF 99.9% OR AT A VOC OUTLET CONCENTRATION OF 10 PPMV.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, STEADY STATE OPERATION				Sulfur, Total Reduced (TRS)	FOLLOW REQUIREMENTS OF 40 CFR 60.18	41.35	LB/H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Other Flares

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, STEADY STATE OPERATION				Sulfur Dioxide (SO2)	FOLLOW SPECIFICATIONS OF 40 CFR 60.18. SEE POLLUTANT NOTES.	3665.97	LB/H	0			TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW 5193 LB/H.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	PRODUCT RECOVERY TOWER FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	RAILCAR LOADING/UNLOADING FUGITIVES				Sulfur, Total Reduced (TRS)	SEE POLLUTANT NOTES.	0.03	LB/H	0			ALL LOADING LINES SHALL BE INSPECTED VISUALLY FOR POSSIBLE LEAK SITES BEFORE THE START OF ANY LOADING OPERATIONS. DAMAGED HOSES SHALL BE REPAIRED OR REPLACED BEFORE ANY LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADING OPERATIONS, ALL LOADING LINES (EXCEPT FOR MMP) SHALL BE PURGED WITH INERT GAS TO THE FLARE BEFORE ANY CONNECTIONS BETWEEN THE LOADING RACKS AND LOADED VESSELS ARE BROKEN. MMP RAILCAR LOADING WILL USE CLOSED LOOP VAPOR BALANCE SYSTEMS CONNECTED TO THE MMP STORAGE TANK OR THE SULFOX-TO. UPON COMPLETION OF MMP LOADING OPERATIONS THE LOADING LINE WILL BE PURGED INTO THE RAILCAR OR THE MMP STORAGE TANK. WHEN UNHOOKING THE RAILCAR FROM THE LOADING LINE, AN ACETIC ACID OR EQUIVALENT WASH WILL BE DONE AFTER EACH MMP LOADING. THE WASH MATERIAL WILL BE NEUTRALIZED AND MANAGED IN THE ON-SITE WASTEWATER SYSTEM. THE WASH MATERIAL TANK WILL VENT TO THE SULFOX-TO.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	DIMETHYL DISULFIDE AREA PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.06	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	(2) STEAM BOILERS, X-426A AND X-426B	NATURAL GAS	15.8	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.01	LB/H	0.0006	LB/MMBTU	EACH, CALCULATED USING THROUGHPUT	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	RUNDOWN TANK FUGITIVES				Sulfur, Total Reduced (TRS)	MMP DAY STORAGE TANKS WILL VENT TO THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULF0X-TO. FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.11	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	STORAGE TANKS FUGITIVES				Sulfur, Total Reduced (TRS)	MMP DAY STORAGE TANKS WILL VENT TO THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULF0X-TO. FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.15	LB/H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Other Flares

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	DIMETHYL SULFIDE AREA PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	H2S PLANT PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, STEADY STATE SERVICE		134.5	MMBTU/H	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, STEADY STATE SERVICE		134.5	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS COMBUSTED IN EACH COMBUSTION EMISSION POINT NUMBER SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	4.21	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	PACKAGE BOILER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE	
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	STANDBY INCINERATOR				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	PACKAGE BOILER BO-4	NAT GAS	60	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.95	LB/H	0 02	LB/MMBTU	CALCULATED USING THROUGHPUT	
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	REGENERATIVE GAS HEATER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE	
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	MONUMENT NO. 2 FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	WASTE HEAT BOILER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE	
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	TRAIN NO. 8 FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	ALKYL FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0380	SYNTHESIS GAS UNIT	TX	06/01/2001 ACT	(2) AIR PREHEATERS 1106 & 1206, F1106SGU &F1206SGU				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE	
TX-0380	SYNTHESIS GAS UNIT	TX	06/01/2001 ACT	FLARE, FS28	SYNGAS			Sulfur Dioxide (SO2)	NONE INDICATED	3337.57	LB/H	0			
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	TX	12/05/2002 ACT	HEATER, STARTUP, MALEIC ANHYDRIDE REACTOR	NATURAL GAS	160.7	mmbtu/h	Sulfur Dioxide (SO2)	PIPELINE QUALITY NATURAL GAS < 2.0 GR S PER 1000 DSCF	0.64	LB/H	0.004	LB/MMBTU	CALCULATED	
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	TX	12/05/2002 ACT	FLARE, BDO UNIT	NATURAL GAS			Sulfur Dioxide (SO2)		0.05	LB/H	0			
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	TX	12/05/2002 ACT	BOILER, SCRUBBER OFF-GAS				Sulfur Oxides (SOx)		7.75	LB/H	0		SEE NOTE	STANDARDIZED EMISSION LIMIT UNAVAILABLE.
TX-0449	UCC SEADRIFT OPERATIONS	TX	04/03/2004 ACT	FLARE BEFOER THE RECYCLE COMPRESSOR PROJECTS IS COMPLETE				Sulfur Dioxide (SO2)	MEETS HEATING VALUES AND VELOCITY REQ. AND BTU ANALYZERS	1.38	LB/H	0			
TX-0449	UCC SEADRIFT OPERATIONS	TX	04/03/2004 ACT	FLARE AFTER THE RECYCLE COMPRESSOR PROJECTS IS COMPLETE				Sulfur Dioxide (SO2)	MEETS HEATING VALUES AND VELOCITY REQ. AND BTU ANALYZERS	1.38	LB/H	0			
TX-0449	UCC SEADRIFT OPERATIONS	TX	04/03/2004 ACT	FLARE NATURAL GAS COMBUSTION (6)	NATURAL GAS			Sulfur Dioxide (SO2)	MEETS HEATING VALUES AND VELOCITY REQ. AND BTU ANALYZERS	0.5	LB/H	0			
TX-0449	UCC SEADRIFT OPERATIONS	TX	04/03/2004 ACT	STARTUP, SHUTDOWN, MAINTENANCE BEFORE THE RECYCLE PROJECT IS COMPLETE (5)				Sulfur Dioxide (SO2)	GOOD PRACTICES	1.38	LB/H	0			
TX-0449	UCC SEADRIFT OPERATIONS	TX	04/03/2004 ACT	STARTUP, SHUTDOWN, MAINTENANCE AFTER THE RECYCLE PROJECT IS COMPLETE (5)				Sulfur Dioxide (SO2)	GOOD PRACTICES	1.38	LB/H	0			
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	TX	03/18/2005 ACT	PILOT PLANT FLARE				Sulfur Dioxide (SO2)		435.27	LB/H	0			
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	TX	03/18/2005 ACT	PROCESS BAG FILTER				Sulfur Dioxide (SO2)		0.15	LB/H	0			
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	TX	03/18/2005 ACT	FEED STOCK OIL PRE HEATER	NATURAL GAS, FUEL OIL, OR FLUE GAS	0.9	MMBTU/H	Sulfur Dioxide (SO2)		0 001	LB/H	0			
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	TX	03/18/2005 ACT	OXYGEN PRE HEATER	NATURAL GAS			Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	COOPER-BESSEMER ENGINE 3105 HP		3105	HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.26	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	HOT OIL HEATER		32.5	MMBTU/H	Sulfur Dioxide (SO2)		0.02	LB/H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Other Flares

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	FLARES (2)				Sulfur Dioxide (SO2)		50.48	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	HP TEG FIREBOX				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	COOPER-BESSEMER ENGINE		2400	HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.36	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	CLARK ENGINE (2)		2000	HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.31	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	INGERSOLL-RAND ENGINE		440	HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.7	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	HOT OIL HEATER		12	MMBTU/H	Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	INGERSOLL-RAND ENGINE 1330 HP		1330	HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.33	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	GLYCOL REBOILER		2.5	MMBUT/H	Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	DHT STRIPPER REBOILER	REFINERY FUEL GAS			Sulfur Dioxide (SO2)		1.9	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	COKER HEATER		291	MMBUT/H	Sulfur Dioxide (SO2)		6.6	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER		62	MMBTU/H	Sulfur Dioxide (SO2)		1.4	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	ACID GAS FLARE				Sulfur Dioxide (SO2)		0.2	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	NO.3 BOILER	REFINERY FUEL GAS	99	MMBTU/H	Sulfur Dioxide (SO2)		2.2	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	TAIL GAS INCINERATOR		100	MMBTU/H	Sulfur Dioxide (SO2)		22.4	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER REBOILER HEATER	REFINERY FUEL GAS	82	MMBTU/H	Sulfur Dioxide (SO2)		5.7	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	SOUR WATER STRIPPER FLARE				Sulfur Dioxide (SO2)		0.19	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	FLARE-COKE DRUM BLOWDOWN				Sulfur Dioxide (SO2)		1056	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	DHT CHARGER HEATER				Sulfur Dioxide (SO2)		2.1	LB/H	0			
TX-0481	AIR PRODUCTS BAYTOWN I I	TX	11/02/2004 ACT	BOILER STACK	NATURAL GAS			Sulfur Dioxide (SO2)		24.2	LB/H	0			
TX-0481	AIR PRODUCTS BAYTOWN I I	TX	11/02/2004 ACT	EMERGENCY GENERATOR				Sulfur Dioxide (SO2)		4.8	LB/H	0			
TX-0481	AIR PRODUCTS BAYTOWN I I	TX	11/02/2004 ACT	FLARE (NORMAL OPERATION)	NATURAL GAS			Sulfur Dioxide (SO2)		0.04	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	L-AREA GAS TURBINE	NATURAL GAS			Sulfur Dioxide (SO2)		0.03	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N5/6 FLARE				Sulfur Dioxide (SO2)		0.11	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N-3 BACKUP INSTRUMENT AIR COMPRESSOR				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N7/8 PREHEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N3/7 FEED AND EXIT GAS FLARE				Sulfur Dioxide (SO2)		0.11	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N-3,4 PREHEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N-5/6 PREHEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0514	ENTERPRISE MONT BELVIEU COMPLEX	TX	01/24/2006 ACT	FLARE-NORMAL OPERATION				Sulfur Dioxide (SO2)		1.1	LB/H	0			
TX-0526	AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	TX	08/18/2006 EST	FLARE PILOTS ONLY				Sulfur Dioxide (SO2)		0 002	LB/H	0			
TX-0526	AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	TX	08/18/2006 EST	FLARE-MSS				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0526	AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	TX	08/18/2006 EST	GAS TURBINE STACK	NATURAL GAS	700	MMBTU/H	Sulfur Dioxide (SO2)		0.92	LB/H	0			
TX-0526	AIR PRODUCTS HYDROGEN, STEAM, AND ELECTRICITY PRODUCTION	TX	08/18/2006 EST	REFORMER FURNACE STACK	STEAM	1373	MMBTU/H	Sulfur Dioxide (SO2)		7.3	LB/H	0			

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Combustion of Misc. Boilers, Furnaces, & Heaters

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	TURBINE, SIMPLE CYCLE, 11 2 MW	FUEL GAS	11.2	MW	Sulfur Dioxide (SO2)	LIMIT FUEL SULFUR CONTENT TO: 200 PPM FUEL GAS H2S, OR FUEL OIL SULFUR CONTENT 0.15% BY WEIGHT	150	PPM @ 15% O2	150	PPM @ 15% O2		DUEL FUEL FIRED TURBINE. OIL-FIRED OPERATIONS LIMITED TO 500 HRS ANNUALLY
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	TURBINE, SIMPLE CYCLE, 36,700 HP	FUEL GAS	27.4	MW	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPM	150	PPM @ 15% O2	150	PPM @ 15% O2		
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	TURBINE, SIMPLE CYCLE, 25 8 MW	FUEL GAS	25800	KW	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPM	150	PPM @ 15% O2	0			
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	HEATER, CRUDE PRODUCTION, 65.6 MMBTU/H	FUEL GAS	65.6	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPMV	0		0			Fuel limit -- no emission rate limit.
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	HEATER, CRUDE PRODUCTION, 65.6 MMBTU/H	FUEL GAS	65.6	MMBTH/H	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPMV.	0		0			fuel sulfur limit -- no emission rate limit
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	HEATER, UHM, 20 MMBTU/H	FUEL GAS	20	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPMV WHEN OPERATING USING LIQUID FUEL: FUEL SULFUR LIMIT OF 215 NG/J (0.50 LB/MMBTU) HEAT INPUT; OR, AS AN ALTERNATIVE, 0.5 WEIGHT PERCENT SULFUR.	0		0			limit is fuel sulfur limit. No emission rate limit
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	HEATER, HMU, 20 MMBTU/H	FUEL GAS	20	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS H2S NOT TO EXCEED 200 PPMV WHEN OPERATING ON FUEL OIL: FUEL SULFUR LIMIT OF 215 NG/J (0.50 LB/MMBTU) HEAT INPUT; OR, AS AN ALTERNATIVE, 0 5 WEIGHT PERCENT SULFUR.	0		0			limit is fuel sulfur limits. No emission rate limits
AK-0056	ALPINE DEVELOPMENT PROJECT, CENTRAL PROCESSING FAC	AK	02/01/1999 ACT	IC ENGINES, 2 MW	FUEL OIL	2	MW	Sulfur Dioxide (SO2)	FUEL OIL SULFUR CONTENT NOT TO EXCEED 0.15% SULFUR BY WEIGHT	0		0			SULFUR LIMIT ON FUEL
AL-0221	LOUISIANA PACIFIC CORPORATION	AL	06/14/2006 ACT	BARK BURNER/DRYER	BARK	85000	lb/h	Sulfur Dioxide (SO2)		4.7	LB/H	0			POLLUTANT INFORMATION CONT.: OPACITY EMISSION LIMIT: 10%, 93% OVERALL EFFICIENCY ODT: OVEN DRIED TON
AL-0221	LOUISIANA PACIFIC CORPORATION	AL	06/14/2006 ACT	BURNER, START UP/SHUT DOWN, NG	NATURAL GAS	30	MMBtu/h	Sulfur Dioxide (SO2)	GOOD DESIGN/OPERATION	0.02	LB/H	0.0006	LB/MMBTU		
AR-0052	THOMAS B. FITZHUGH GENERATING STATION	AR	02/15/2002 ACT	TURBINE, COMBINED CYCLE, NATURAL GAS	NATURAL GAS	170.6	MW	Sulfur Dioxide (SO2)	GOOD COMBUSTION.	1	PPM @ 15% 02	0			
AR-0052	THOMAS B. FITZHUGH GENERATING STATION	AR	02/15/2002 ACT	HEAT RECOVERY STEAM GENERATOR (DUCT BURNER)	NATURAL GAS	220	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES AND DESIGN.	1	PPM @ 15% O2	0		NOT AVAILABLE	Standardized units not available.
AR-0052	THOMAS B. FITZHUGH GENERATING STATION	AR	02/15/2002 ACT	TURBINE, COMBINED CYCLE, FUEL OIL	NO. 2 FUEL OIL	170.6	MW	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES, FUEL S LIMIT: < 0.33% S BY WT	85	PPM@ 15% O2	0			
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	FURNACE, LADLE METALLURGY		225	T/H	Sulfur Dioxide (SO2)	LOW SULFUR COKE USE.	0 076	LB/T	0			
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	PROCESS HEATERS	NATURAL GAS			Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICE	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	FURNACE, ELECTRIC ARC		225	T/H	Sulfur Dioxide (SO2)	LOW SULFUR COKE/SCRAP MANAGEMENT.	1.5	LB/T	0			
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	REHEAT FURNACE	NATURAL GAS	225	MMBTU/H	Sulfur Dioxide (SO2)	CLEAN FUELS	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	AR	10/10/2001 ACT	LADLE PREHEAT & DRYOUT STATIONS	NATURAL GAS	225	T/H	Sulfur Dioxide (SO2)	CLEAN FUEL	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	BRINE REDUCTION AREA SN-PBCDF-07	NATURAL GAS	0 01	MMDSCF/H	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS ONLY.	0.1	LB/H	0.008	LB/MMBTU	CALCULATED	
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	BOILER, HOT WATER, (2) SN-PBCDF-05, -06	NATURAL GAS	0 01	MMDSCF/H	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS ONLY.	0.1	LB/H	0.0085	LB/MMBTU	CALCULATED	
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	INCINERATOR COMMON STACK SN-PBCDF-01	NAT GAS, CHEM AGENT	40	ROCKETS/H	Sulfur Dioxide (SO2)	QUENCH TOWER WITH CAUSTIC SCRUBBING LIQUID FOLLOWED BY VENTURI SCRUBBER (COMBINED EFFICIENCY 50%), FOLLOWED BY A PACKED-BED SCRUBBER (95% EFFICIENCY). OVERALL SYSTEM IS EXPECTED TO REMOVE 97.5% OF SO2.	17.2	LB/H	0			THE MOST STRINGENT CONTROL WAS SELECTED: A PACKED BED SCRUBBER, IN CONJUNCTION WITH A QUENCH TOWER AND VENTURI SCRUBBER.
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	BOILER, PROCESS STEAM, (2) SN-PBCDF-03, -04	NATURAL GAS	0 03	MMDSCF/H	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS ONLY.	0.1	LB/H	0.0035	LB/MMBTU	CALCULATED	

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	BOILER, LABORATORY SN-PBCDF-16	NATURAL GAS	1.4	mmbtu/h	Sulfur Dioxide (SO2)	LOW-SULFUR NATURAL GAS ONLY.	0.1	LB/H	0.071	LB/MMBTU	CALCULATED	
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	IC ENGINE, EMERGENCY GENERATOR (2)	DIESEL FUEL	2500	KW	Sulfur Dioxide (SO2)	LOW SULFUR DIESEL: LESS THAN OR EQUAL TO 0.05 WT % S. ALSO: LIMITATION OF OPERATING HOURS TO LESS THAN 1200 COMBINED HOURS/YR FOR SN-PBCDF-09 AND SN-PBCDF-10 AND LESS THAN 500 HOURS/YR FOR SN-PBCDF-12.	0.6	LB/H	0			
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	AR	02/17/2004 ACT	IC ENGINE, EMERGENCY GENERATOR SN-PBCDF-12	DIESEL FUEL	250	KW	Sulfur Dioxide (SO2)	LOW SULFUR DIESEL; <= 0.05 WT % S. ALSO OPERATING LIMIT: < 500 H/YR.	0.4	LB/H	0			
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	GALVANIZING LINE	NATURAL GAS	9	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY	0.0006	LB/MMBTU	0			
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	BOILERS	NATURAL GAS	22	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	DEGASSER HOTWELL FLARE	NATURAL GAS			Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY IN FLARE	0.09	LB/H	0			
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	TUNNEL FURNACE	NATURAL GAS	160	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY	0.0006	LB/MMBTU	0.0006	LB/MMBTU		ADDITIONAL LIMIT: .1 LB/H
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	ELECTRIC ARC FURNACE (EAF)	NATURAL GAS	350	t/h	Sulfur Dioxide (SO2)	LOW SULFUR COKE AND SCRAP MANAGEMENT	0.2	LB/T	0			
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	LADLE METALLURGY FURNACE		350	T/H	Sulfur Dioxide (SO2)		0.08	LB/T	0			
AR-0077	BLUEWATER PROJECT	AR	07/22/2004 ACT	FURNACES, HEATERS, & DRYERS	NATURAL GAS	11	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS COMBUSTION ONLY	0.0006	LB/MMBTU	0.0006	LB/MMBTU		
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FL	07/30/2008 ACT	THREE NOMINAL 250 MW CTG (EACH) WITH SUPPLEMENTARY-FIRED HRSG	NATURAL GAS	2333	MMBTU/H	Sulfur Oxides (SOx)		2	GR S/100SCF	0			THE SULFUR FUEL SPECIFICATIONS COMBINED WITH THE EFFICIENT COMBUSTION DESIGN AND OPERATION OF EACH CTG REPRESENTS (BACT) FOR PM/PM10/PM2.5 EMISSIONS. COMPLIANCE WITH THE FUEL SPECIFICATIONS, CO STANDARDS, AND VISIBLE EMISSIONS STANDARDS SHALL SERVE AS INDICATORS OF GOOD COMBUSTION. COMPLIANCE WITH THE FUEL SPECIFICATIONS SHALL BE DEMONSTRATED BY KEEPING RECORDS OF THE FUEL SULFUR CONTENT. COMPLIANCE WITH THE VISIBLE EMISSIONS STANDARD SHALL BE DEMONSTRATED BY CONDUCTING TESTS IN ACCORDANCE WITH EPA METHOD 9.
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FL	07/30/2008 ACT	TWO NOMINAL 10 MMBTU/H NATURAL GAS-FIRED PROCESS HEATERS	NATURAL GAS	10	MMBTU/H	Sulfur Dioxide (SO2)		2	GS/100 SCF	0			VOC, SO2, PM/PM10 2 GR S/100SCF NATURAL GAS SPEC AND 10% OPACITY
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FL	07/30/2008 ACT	TWO NOMINAL 2,250 KW (~ 21 MMBTU/H) EMERGENCY GENERATORS	ULTRA LOW SULFUR OIL	21	MMBTU/H	Sulfur Dioxide (SO2)	ULTRA LOW FUEL OIL	0.0015	%	0			
ID-0010	MIDDLETON FACILITY	ID	10/19/2001 ACT	(2) GAS TURBINES ANNUAL EMISSION LIMITS, BOTH FUEL	NATURAL GAS			Sulfur Oxides (SOx)	THE DISTILLATE FUEL OIL BURNED IN ANY TURBINE SHALL NOT CONTAIN SULFUR IN EXCESS OF 0.05% BY WEIGHT. THE NATURAL GAS BURNED IN ANY TURBINE OR DUCT BURNER SHALL NOT EXCEED 1 GR/100 SCF.	36.4	T/YR	0			
ID-0010	MIDDLETON FACILITY	ID	10/19/2001 ACT	(2) GAS TURBINES WITHOUT DUCT BURNERS, DIST	DISTILLATE FUEL	1699	MMBTU/H	Sulfur Oxides (SOx)	DISTILLATE FUEL OIL BURNED IN ANY TURBINE SHALL NOT CONTAIN SULFUR IN EXCESS OF 0 05% BY WEIGHT.	92.9	LB/H	0			
ID-0010	MIDDLETON FACILITY	ID	10/19/2001 ACT	(2) DUCT BURNERS	NATURAL GAS	390	MMBTU/H	Sulfur Dioxide (SO2)	THE NATURAL GAS BURNED IN ANY DUCT BURNER SHALL NOT CONTAIN SULFUR IN EXCESS OF 1 GR/100 SCF.	0.2	LB/MMBTU	0.2	LB/MMBTU	EA	THE PERMITTEE SHALL NOT DISCHARGE ANY GASES FROM COMBUSTION OF LIQUID OR GASEOUS FUELS WHICH CONTAIN SO2 IN EXCESS OF 100% OF THE POTENTIAL COMBUSTION CONCENTRATION WHEN EMISSIONS ARE LESS THAN 0.20 LB/MMBTU HEAT INPUT.
ID-0010	MIDDLETON FACILITY	ID	10/19/2001 ACT	(2) GAS TURBINES WITH DUCT BURNERS, NAT GAS	NATURAL GAS	2097	MMBTU/H	Sulfur Oxides (SOx)	THE NATURAL GAS BURNED IN ANY TURBINE OR DUCT BURNER SHALL NOT CONTAIN SULFUR IN EXCESS OF 1 GR/100 SCF.	6.6	LB/H	0			
ID-0010	MIDDLETON FACILITY	ID	10/19/2001 ACT	(2) GAS TURBINES WITHOUT DUCT BURNERS, NAT GAS	NATURAL GAS			Sulfur Oxides (SOx)	THE NATURAL GAS BURNED IN ANY TURBINE OR DUCT BURNER SHALL NOT CONTAIN SULFUR IN EXCESS OF 1 GR/100 SCF.	5.4	LB/H	0			

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*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	SYNGAS HYDROCARBON FLARE	SYNGAS	0 27	MMBTU/H	Sulfur Dioxide (SO2)	A FLARE MINIMIZATION PLAN	0		0			IDENTIFIED AS (EU-001) SHALL BE LIMITED AS FOLLOWS: A. THE PERMITTEE SHALL COMPLY WITH THE FOLLOWING FLARE MINIMIZATION PLAN TO REDUCE SO2 EMISSIONS DURING STARTUPS, SHUTDOWNS, AND OTHER FLARING EVENTS. THE PERMITTEE WILL USE METHANOL, RATHER THAN COAL OR PET COKE, AS THE FEEDSTOCK IN EACH GASIFIER DURING STARTUP CONDITIONS REQUIRING SYNGAS FLARING, THEREBY REDUCING EMISSIONS OF SULFUR DIOXIDE AT THE SYNGAS HYDROCARBON FLARE. DURING A PLANNED SHUTDOWN OF A GASIFIER, THE PERMITTEE SHALL ROUTE THE CONTENTS OF EACH GASIFIER UNIT (GASIFIER VESSEL, QUENCH CHAMBER, SCRUBBER VESSEL) DURING INITIAL DEPRESSURIZATION TO ONE OF THE WET SULFURIC ACID (WSA) PLANTS. THE PERMITTEE SHALL REDUCE GASIFIER FEED RATES SUCH THAT ALL SYNGAS CAN BE PROCESSED THROUGH ONE GAS TREATMENT TRAIN PRIOR TO A SCHEDULED GAS TREATMENT TRAIN OUTAGE. THIS LIMITS THE AMOUNT OF SYNGAS THAT WILL HAVE TO BE SENT TO THE SYNGAS HYDROCARBON FLARE. THE PERMITTEE SHALL HAVE WRITTEN PROCEDURES FOR THE ABOVE OPERATIONS AND THE PERMITTEE SHALL TRAIN THE OPERATORS ON THESE PROCEDURES.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	ACID GAS FLARE	ACID GAS	0 27	MMBTU	Sulfur Dioxide (SO2)	FLARE MINIMIZATION PLAN	0		0			EMISSION LIMITS: NONE (3) THE SO2 EMISSIONS FROM THE ACID GAS FLARE, IDENTIFIED AS (EU-002) SHALL BE LIMITED AS FOLLOWS: A. THE PERMITTEE SHALL COMPLY WITH THE FOLLOWING FLARE MINIMIZATION PLAN TO REDUCE EMISSIONS DURING FLARING EVENTS. THE PERMITTEE SHALL INVESTIGATE THE ?ROOT CAUSE? OF MALFUNCTION EVENTS THAT CAUSE GASES TO BE SENT TO A FLARE AND DETERMINE WHETHER THERE ARE ADDITIONAL PREVENTATIVE MEASURES THAT CAN BE IMPLEMENTED TO MINIMIZE RE-OCCURRENCE OF THESE EVENTS. SUCH IDENTIFIED MEASURES SHALL BE IMPLEMENTED AND DOCUMENTED.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	TWO (2) AUXILIARY BOILERS	NATURAL GAS	408	MMBTU/H, EACH	Sulfur Dioxide (SO2)	USE OF NATURAL GAS OR SNG	0.0006	MMBTU/H	0			
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	REGENERATIVE THERMAL OXIDIZER (RTO) ON THE ACID GAS REMOVAL UNIT VENTS (AGR)	NATURAL GAS	38.8	MMBTU/H, EACH	Sulfur Dioxide (SO2)	RECTISOL ACID GAS REMOVAL SYSTEM	3.17	LB/H	0			EMISSION LIMIT 1 IS FOR EACH RTO.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	FIVE (5) GASIFIER PREHEAT BURNERS	NATURAL GAS AND SNG	35	MMBTU/H, EACH	Sulfur Dioxide (SO2)	USE OF CLEAN BURNING GASEOUS FUEL	0.0006	LB/MMBTU	0			EMISSION LIMIT IS FOR EACH BURNER.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	TWO (2) EMERGENCY GENERATORS	DIESEL	1341	HORSEPOWER, EACH	Sulfur Dioxide (SO2)	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION	15	PPM SULFUR	0			EMISSION LIMIT: EACH EMERGENCY GENERATOR SHALL NOT EXCEED 52 HOURS PER YEAR OF NONEMERGENCY OPERATION.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	THREE (3) FIREWATER PUMP ENGINES	DIESEL	575	HORSEPOWER, EACH	Sulfur Dioxide (SO2)	USE OF LOW-S DIESEL AND LIMITED HOURS OF NON-EMERGENCY OPERATION	15	PPM SULFUR	0			EMISSION LIMITS: EACH EMERGENCY GENERATOR SHALL NOT EXCEED 52 HOURS PER YEAR OF NONEMERGENCY OPERATION.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	TWO (2) WET SULFURIC ACID PLANTS	STPD	800	STPD	Sulfur Dioxide (SO2)	PEROXIDE SCRUBBER	0.25	LB/T ACID PRODUCED	0			EMISSION LIMIT IS FOR EACH UNIT.
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	ZLD SPRAY DRYER		5.6	MMBTU/H	Sulfur Dioxide (SO2)	USE OF A CLEAN BURNING GASEOUS FUEL	0		0			
*IN-0166	INDIANA GASIFICATION, LLC	IN	06/27/2012 ACT	FUGITIVE LEAKS FROM PIPING		0		Sulfur Dioxide (SO2)	LEAK DETECTION AND REPAIR (LDAR) PROGRAM	0		0			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	SPACE HEATERS	NATURAL GAS	1	MMBTU/H EACH	Sulfur Dioxide (SO2)	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0005	LB/MMBTU	0			LIMIT IS FOR EACH HEATER
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	COKE BREEZE ADDITIVE SYSTEM AIR HEATER	NATURAL GAS	1.7	MMBTU/H	Sulfur Dioxide (SO2)	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0005	LB/MMBTU	0			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	EMERGENCY GENERATOR	NATURAL GAS	620	HP	Sulfur Dioxide (SO2)	USE OF NATRUAL GAS AND GOOD COMBUSTION PRACTICES	0.0015	G/KW-H	0			

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*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	FIRE WATER PUMP	NATURAL GAS	300	HP	Sulfur Dioxide (SO2)	USE OF NATUAL GAS AND GOOD COMBUSTION PRACTICES	0.0015	G/KW-H	0			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	COKE BREEZE ADDITIVE SYSTEM		16.5	T/H	Sulfur Dioxide (SO2)		0.0005	LB/MMBTU	0			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	GROUND LIMESTONE/DOLOMITE ADDITIVE SYSTEM AIR HEATER	NATURAL GAS	19	MMBTU/H	Sulfur Dioxide (SO2)	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0005	LB/MMBTU	0			
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	FURNACE HOOD EXHAUST	NATURAL GAS	436	MMBTU/H	Sulfur Dioxide (SO2)		21.68	LB/H	0			LIMIT ONE: 7.1 PPMV WET AT 20% O2 NOTE: 0.089 LB SO2/TON PELLETS * 450 TONS/HR = 40.1 LB/HR SO2
*IN-0167	MAGNETATION LLC	IN	04/16/2013 ACT	FURNACE WINDBOX EXHAUST (WBE)	NATURAL	436	MMBTU/H	Sulfur Dioxide (SO2)	GSA DRY SCRUBBER AND BAGHOUSE CE016	19.61	LB/H	0			LIMIT ONE: 5.0 PPMV WET AT 15% O2 NOTE: 0.048 LB SO2/TON PELLETS * 450 TONS/HR = 21.6 LB/HR SO2
LA-0262	SULFURIC ACID REGENERATION PLANT	LA	05/03/2012 ACT	SULFURIC ACID PLANT STACK (1-76, EQT 0051)		2400	T/D	Sulfur Dioxide (SO2)	DOUBLE CONTACT DOUBLE ABSORPTION TECHNOLOGY	434	LB/H	0			
LA-0262	SULFURIC ACID REGENERATION PLANT	LA	05/03/2012 ACT	ACID REGENERATION UNIT FUGITIVES (10-92, FUG 0003)		0		Sulfur Dioxide (SO2)		6.66	LB/H	0			
LA-0262	SULFURIC ACID REGENERATION PLANT	LA	05/03/2012 ACT	START-UP HEATER STACK (37-88, EQT 0053)	NATURAL GAS	61	MMBTU/H	Sulfur Dioxide (SO2)	USE OF NATURAL GAS AS FUEL	0.04	LB/H	0			OPERATION LIMITED TO 340 HR/YR.
LA-0262	SULFURIC ACID REGENERATION PLANT	LA	05/03/2012 ACT	ACID PLANT AIR PREHEATER (1-95, EQT 0074)	NATURAL GAS	86	MMBTU/H	Sulfur Dioxide (SO2)	USE OF NATURAL GAS AND/OR LANDFILL GAS AS FUEL	1.94	LB/H	0			
MI-0301	ALCHEM ALUMINUM	MI	05/02/2000 ACT	SIDE-WELLS	NATURAL GAS	42000	LB/H	Sulfur Dioxide (SO2)	SIDE WELL EMISSIONS PASS THROUGH LIME-INJECTED BAGHOUSES. NO CONTROL CLAIMED, %.	0.52	LB/H	0	LB/MMBTU		
MI-0301	ALCHEM ALUMINUM	MI	05/02/2000 ACT	CRUSHER	NA	20000	LB/H	Sulfur Dioxide (SO2)	N/A	1.47	LB/H	0	LB/MMBTU		
MI-0301	ALCHEM ALUMINUM	MI	05/02/2000 ACT	CRUCIBLE HEATERS/STATIONS	NATURAL GAS	2	MMBTU/H EACH	Sulfur Dioxide (SO2)	N/A	0.01	LB/H	0		NOT AVAILABLE	
MI-0301	ALCHEM ALUMINUM	MI	05/02/2000 ACT	FLUES	NATURAL GAS	42000	LB/H	Sulfur Dioxide (SO2)	COMBUSTION FLUES ARE WITHOUT ADD-ON CONTROLS. ONLY PIPELINE QUALITY NATURAL GAS FOR FUEL.	0.12	LB/H	0	LB/MMBTU		
MS-0077	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	03/04/2005 ACT	LIME KILN	NATURAL GAS	145.9	MMBTU/H	Sulfur, Total Reduced (TRS)	WET (VENTURI) SCRUBBER WITH OPTIONAL MUD WASHING	20	PPMV @ 10% O2	20	PPMV @ 10% O2		LIMIT IS PPM EXPRESSED AS H2S ON A DRY GAS BASIS, CORRECTED TO 10% O2 (12-HOUR BASIS)
MS-0077	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	03/04/2005 ACT	LIME KILN	NATURAL GAS	145.9	MMBTU/H	Sulfur Dioxide (SO2)	WET (VENTURI) SCRUBBER WITH OPTIMAL MUD WASHING	23.4	LB/H	0			ADDITIONAL LIMIT: 50 PPMV ON DRY GAS BASIS CORRECTED TO 10% O2.
MS-0077	GEORGIA PACIFIC CORPORATION, MONTICELLO MILL	MS	03/04/2005 ACT	AIR HEATER, PETROLEUM COKE	NATURAL GAS	5	MMBTU/H	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES	0		0			NO EMISSION LIMITS
NM-0044	CLOVIS ENERGY FACILITY	NM	06/27/2002 ACT	AUXILIARY BOILERS (AUX-1 AND AUX-2)	NATURAL GAS	33	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS, GOOD COMBUSTION PRACTICE	0.1	LB/H	0.003	LB/MMBTU	calculated	
NM-0044	CLOVIS ENERGY FACILITY	NM	06/27/2002 ACT	TURBINES, COMBINED CYCLE, NATURAL GAS (4)	NATURAL GAS	1515	MMBTU/H	Sulfur Dioxide (SO2)	PIPELINE QUALITY NATURAL GAS, GOOD ENGINEERING PRACTICE	4.3	LB/H	0			
NM-0044	CLOVIS ENERGY FACILITY	NM	06/27/2002 ACT	DUCT BURNERS (DB-1 AND DB-2)	NATURAL GAS	643	MMBTU/H	Sulfur Dioxide (SO2)	PIPELINE QUALITY NATURAL GAS, GOOD COMBUSTION PRACTICE.	1.5	LB/H	0.002	LB/MMBTU	calculated	
OH-0349	GRAFTECH INTERNATIONAL HOLDINGS, INC.	OH	04/27/2011 ACT	Graphite Furnaces (12)		0		Sulfur Dioxide (SO2)		12.9	LB/H	0			
OH-0349	GRAFTECH INTERNATIONAL HOLDINGS, INC.	OH	04/27/2011 ACT	Graphite Rolling Lines (4)	natural gas	0		Sulfur Dioxide (SO2)	Scrubber	15.6	LB/H	0			If required Method 6
OH-0349	GRAFTECH INTERNATIONAL HOLDINGS, INC.	OH	04/27/2011 ACT	West Treatment System		0		Sulfur Dioxide (SO2)		0.24	LB/H	0			If required Method 6
OK-0112	MUSKOGEE MILL	OK	03/27/2006 ACT	PAPER MACHINE COMBUSTION #11-14				Sulfur Dioxide (SO2)	EXISTING CONTROL - CLEAN FUEL	0.2	T/YR	0			
SC-0060	RAINEY GENERATING STATION	SC	04/03/2000 ACT	TURBINES, SIMPLE CYCLE, DISTILLATE FUEL OIL (2)	DISTILLATE FUEL OIL	170	MW (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, MAXIMUM SULFUR CONTENT OF 0.05%	105.6	LB/H	0			
SC-0060	RAINEY GENERATING STATION	SC	04/03/2000 ACT	TURBINES, COMBINED CYCLE, NATURAL GAS (2)	NATURAL GAS	170	MW (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	2.1	LB/H	0			ADDITIONAL EMISSION LIMIT: 0.4 GR/100 SCF, EACH TURBINE
SC-0060	RAINEY GENERATING STATION	SC	04/03/2000 ACT	TURBINES, SIMPLE CYCLE, NATURAL GAS (2)	NATURAL GAS	170	MW (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	2.1	LB/H	0			ADDITIONAL EMISSION LIMIT: 0.4 GR/100 SCF, EACH TURBINE
SC-0060	RAINEY GENERATING STATION	SC	04/03/2000 ACT	TURBINES, COMBINED CYCLE, DISTILLATE FUEL OIL (2)	DISTILLATE FUEL OIL	170	MW (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	105.6	LB/H	0			
SC-0060	RAINEY GENERATING STATION	SC	04/03/2000 ACT	HEATERS, PROCESS (2)	NATURAL GAS	2.9	MMBTU/H (EACH)	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	3.5	LB/MMBTU	3.5	LB/MMBTU	EACH	
TN-0078	WAUPACA FOUNDRY, INC.	TN	04/28/2000 ACT	SPACE HEATERS - MAKE-UP AIR	NATURAL GAS, PROPANE	0.1	MMCF/H	Sulfur Dioxide (SO2)		0.06	LB/H	0			
TN-0088	SATURN - SPRING HILL	TN	06/06/2000 ACT	MAJOR PANEL TOPCOAT OPERATIONS	NATURAL GAS			Sulfur Dioxide (SO2)	NATURAL GAS, GOOD COMBUSTION CONTROL	0		0			EMISSIONS ARE REFLECTED IN PAL

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Combustion of Misc. Boilers, Furnaces, & Heaters

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TN-0088	SATURN - SPRING HILL	TN	06/06/2000 ACT	SPACE FRAME AND SHEET METAL E-COAT SYSTEM				Sulfur Dioxide (SO2)	NATURAL GAS, GOOD COMBUSTION CONTROL	0		0			EMISSIONS ARE REFLECTED IN PAL
TN-0088	SATURN - SPRING HILL	TN	06/06/2000 ACT	MAJOR PANEL PRIME SYSTEM	NATURAL GAS			Sulfur Dioxide (SO2)	NATURAL GAS, GOOD COMBUSTION CONTROL	0		0			EMISSIONS ARE REFLECTED IN PAL
TN-0088	SATURN - SPRING HILL	TN	06/06/2000 ACT	FASCIA/REPROCESS TOPCOAT (BASE AND CLEARCOAT)				Sulfur Dioxide (SO2)	NATURAL GAS, GOOD COMBUSTION CONTROL	0		0			EMISSIONS ARE REFLECTED IN PAL
TN-0088	SATURN - SPRING HILL	TN	06/06/2000 ACT	SPACE FRAME UNDERBODY PVC/SEAM SEAL APPLICATION				Sulfur Dioxide (SO2)	NATURAL GAS, GOOD COMBUSTION CONTROL	0		0			EMISSIONS REFLECTED IN PAL
TN-0088	SATURN - SPRING HILL	TN	06/06/2000 ACT	SITE-WIDE PRODUCTS OF COMBUSTION	NATURAL GAS			Sulfur Dioxide (SO2)	NATURAL GAS, GOOD COMBUSTION CONTROL	0		0			EMISSIONS ARE REFLECTED IN PAL
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	TN	04/03/2002 ACT	SULFUR RECOVERY UNIT				Sulfur Dioxide (SO2)		150	PPM	75	PPMV @ 0% EXCESS AIR	annual avg.	
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	TN	04/03/2002 ACT	HEATERS, (5)	NATURAL GAS	50	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR LIMITS	0		0			no emission rate limits. Natural gas: 50 ppm H2S in fuel - annual; fuel gas: 100 ppm H2S in fuel - 24 h avg.
TN-0156	MEMPHIS GENERATION, LLC	TN	04/09/2001 ACT	TURBINE, COMBINED CYCLE, DUCT BURNER, NATURAL GAS	NATURAL GAS	14583	MMSCF/YR	Sulfur Dioxide (SO2)		150	PPM @ 15% O2	0			
TN-0156	MEMPHIS GENERATION, LLC	TN	04/09/2001 ACT	BOILER, AUXILIARY, NATURAL GAS	NATURAL GAS	180	MMSCF	Sulfur Dioxide (SO2)	CLEAN FUEL	0.01	LB/H	0.0005	LB/MMBTU	calculated	permit limit is in lb/h.
TN-0156	MEMPHIS GENERATION, LLC	TN	04/09/2001 ACT	DUCT BURNER	NATURAL GAS	300	MMBTU/H	Sulfur Dioxide (SO2)		0.2	LB/MMBTU	0.2	LB/MMBTU		
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	SOAP RECOVERY AND STORAGE				Sulfur, Total Reduced (TRS)	NONE INDICATED	0.05	LB/H	0			
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	WEAK BLACK LIQUOR STORAGE				Sulfur, Total Reduced (TRS)	NONE INDICATED	0.06	LB/H	0			
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	HEAVY BLACK LIQUOR STORAGE				Sulfur, Total Reduced (TRS)	NONE INDICATED	0.18	LB/H	0			
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	BROWN KRAFT PULP STORAGE				Sulfur, Total Reduced (TRS)	NONE INDICATED	0.18	LB/H	0			
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	BLEACHED KRAFT PULP STORAGE				Sulfur, Total Reduced (TRS)	NONE INDICATED	0.18	LB/H	0			
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	MISC. STORAGE				Sulfur, Total Reduced (TRS)	NONE INDICATED	0.04	LB/H	0			
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	LIME KILN	NAT GAS, NO.2 OIL			Sulfur, Total Reduced (TRS)	SCRUBBER	0.9	LB/H	0			
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	LIME KILN	NAT GAS, NO.2 OIL			Sulfur Dioxide (SO2)	SCRUBBER AND SWEET NAT GAS WITH A SULFUR CONTENT LIMIT OF 0.3%	5.4	LB/H	0			
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	SLAKER				Sulfur, Total Reduced (TRS)	NONE INDICATED	0.1	LB/H	0			
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	RECOVERY BOILER				Sulfur Dioxide (SO2)	NONE INDICATED	206	LB/H	0			ADDITIONAL LIMIT: SO2 FROM REC BOILER NOT TO EXCEED 250 PPM DRY BASIS, BASED ON A 12-HR AVER.
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	RECOVERY BOILER				Sulfur, Total Reduced (TRS)	NONE INDICATED	2.7	LB/H	0			
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	SMELT TANK				Sulfur, Total Reduced (TRS)	NONE INDICATED	1.4	LB/H	0			
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	SMELT TANK				Sulfur Dioxide (SO2)	NONE INDICATED	2.5	LB/H	0			
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	BLOW HEAT SYSTEM				Sulfur, Total Reduced (TRS)	NONE INDICATED	0.23	LB/H	0			
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	BROWN STOCK WASHERS				Sulfur, Total Reduced (TRS)	NONE INDICATED	9.82	LB/H	0		NOT AVAILABLE	
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	POWER BOILER NOS. 4, 5, 8, AND 9				Sulfur Dioxide (SO2)	NONE INDICATED	1.4	T/YR	0		NOT AVAILABLE	NEED EMISSION LIMIT IN STANDARD UNITS
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	TURBINE				Sulfur Dioxide (SO2)	NONE INDICATED	0.14	LB/H	0			
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	LIME MUD CLARIFICATION AND STORAGE				Sulfur, Total Reduced (TRS)	NONE INDICATED	0.02	LB/H	0			
TX-0263	DONAHUE INDUSTRIES, INC. PAPER MILL	TX	10/17/2000 ACT	POWER BOILER 11				Sulfur Dioxide (SO2)	NONE INDICATED	5.4	LB/H	0		NOT AVAILABLE	
TX-0292	TEMPLE INLAND PINELAND MANUFACTURING COMPLEX	TX	08/06/2000 EST	(2) KILN, DRYING, STUDMILLS 1&2, EPN91&92		3 25	T/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.07	LB/H	0			FUGITIVE EMISSIONS ARE AN ESTIMATE ONLY AND SHOULD NOT BE CONSIDERED AS A MAXIMUM ALLOWABLE EMISSION RATE.
TX-0292	TEMPLE INLAND PINELAND MANUFACTURING COMPLEX	TX	08/06/2000 EST	BOILER, WOOD-FIRED, EPN22	WOOD	20.5	T/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.16	LB/H	0		NOT AVAILABLE	
TX-0299	KAUFMAN COGEN LP	TX	01/31/2000 ACT	(2) GAS TURBINES, HRSG-1 & -2	NAT GAS	180	MW, EACH	Sulfur Dioxide (SO2)	LIMITED TO PIPELINE QUALITY NAT GAS CONTAINING NO MORE THAN 2.0 GR S/100 DSCF	10	LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0299	KAUFMAN COGEN LP	TX	01/31/2000 ACT	FIREWATER PUMP ENGINE, FWP-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.8	LB/H	0			
TX-0299	KAUFMAN COGEN LP	TX	01/31/2000 ACT	AUX. BOILER, B-1	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.02	LB/H	0		NOT AVAILABLE	
TX-0314	GLOBAL OCTANES DEER PARK FACILITY	TX	06/15/1999 ACT	CHARGE HEATER, H-101 AND STEAM BOILER, U-5001	NAT GAS	180	MMBTU/H	Sulfur Dioxide (SO2)	NAT GAS OR NAT GAS/PLANT GAS MIXTURE	25	T/YR	0		NOT AVAILABLE	
TX-0315	EXXON MOBIL BAYTOWN REFINERY	TX	07/12/1999 ACT	(2) VACUUM PIPE STILL 8 FURNACES, VPS 8, F-803&4	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	60.9	LB/H	0			
TX-0315	EXXON MOBIL BAYTOWN REFINERY	TX	07/12/1999 ACT	(2) SULFUR CONVERSION UNIT (SCU) 2, INCINERATOR				Sulfur Dioxide (SO2)	NONE INDICATED	0.73	LB/H	0		NOT AVAILABLE	ASSUMED NSPS SUBPART J APPLIED. EMISSIONS DURING HOT STANDBY ONLY. INCINERATORS ARE FOR UPSET AND MAINTENANCE PROCEDURES ONLY.
TX-0315	EXXON MOBIL BAYTOWN REFINERY	TX	07/12/1999 ACT	FLEXICOKING (FXK), F-301 & HC SKIMMER DRUM	LBG	110	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	49.8	LB/H	0			
TX-0315	EXXON MOBIL BAYTOWN REFINERY	TX	07/12/1999 ACT	HF 3, F-1	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	108.1	LB/H	0		NOT AVAILABLE	THE FOLLOWING EMISSION LIMIT SHALL BE EFFECTIVE WHEN THE VACUUM PIPE STILL 8 FURNACES (PS8F03 AND PS8F804) ARE NOT FIRING: 130 5 LB/H, 554 T/YR
TX-0315	EXXON MOBIL BAYTOWN REFINERY	TX	07/12/1999 ACT	HF 3, F-2	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	119.5	LB/H	0		NOT AVAILABLE	THE FOLLOWING EMISSION LIMIT SHALL BE EFFECTIVE WHEN THE VACUUM PIPE STILL 8 FURNACES (PS8F03 AND PS8F804) ARE NOT FIRING: 144 3 LB/H, 614 T/YR
TX-0315	EXXON MOBIL BAYTOWN REFINERY	TX	07/12/1999 ACT	HF 3, F-3	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	83.6	LB/H	0		NOT AVAILABLE	THE FOLLOWING EMISSION LIMIT SHALL BE EFFECTIVE WHEN THE VACUUM PIPE STILL 8 FURNACES (PS8F03 AND PS8F804) ARE NOT FIRING: 101 0 LB/H, 429 T/YR
TX-0315	EXXON MOBIL BAYTOWN REFINERY	TX	07/12/1999 ACT	HF 3, F-4	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	58.1	LB/H	0		NOT AVAILABLE	THE FOLLOWING EMISSION LIMIT SHALL BE EFFECTIVE WHEN THE VACUUM PIPE STILL 8 FURNACES (PS8F03 AND PS8F804) ARE NOT FIRING: 70.2 LB/H, 298 T/YR
TX-0315	EXXON MOBIL BAYTOWN REFINERY	TX	07/12/1999 ACT	(2) PIPE STILL 8, FURNACES, PS 8, F-801& F-802	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	190.2	LB/H	0		NOT AVAILABLE	
TX-0315	EXXON MOBIL BAYTOWN REFINERY	TX	07/12/1999 ACT	HYDROFORMER 4 FURNACE, HF 4, F-401	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	243.4	LB/H	0			
TX-0315	EXXON MOBIL BAYTOWN REFINERY	TX	07/12/1999 ACT	HYDROFORMER 4 FURNACE, HF 4, F-402	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	232.9	LB/H	0		NOT AVAILABLE	
TX-0315	EXXON MOBIL BAYTOWN REFINERY	TX	07/12/1999 ACT	HF 4, F-403	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	131.2	LB/H	0		NOT AVAILABLE	
TX-0315	EXXON MOBIL BAYTOWN REFINERY	TX	07/12/1999 ACT	HF 4, F-404	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	124.6	LB/H	0		NOT AVAILABLE	
TX-0315	EXXON MOBIL BAYTOWN REFINERY	TX	07/12/1999 ACT	(4) BH 7, WHB-71 THRU -74	LBG			Sulfur Dioxide (SO2)	NONE INDICATED	65.1	LB/H	0		NOT AVAILABLE	
TX-0315	EXXON MOBIL BAYTOWN REFINERY	TX	07/12/1999 ACT	FLEXICOKING GAS TURBINE/WASTE HEAT BOILER				Sulfur Dioxide (SO2)	NONE INDICATED	100.1	LB/H	0			
TX-0316	ANHEUSER-BUSH HOUSTON BREWERY	TX	07/13/1999 ACT	(3) BOILERS NO 1-3, PWR-1 TO -3	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	24.3	LB/H	0		NOT AVAILABLE	
TX-0316	ANHEUSER-BUSH HOUSTON BREWERY	TX	07/13/1999 ACT	(2) BOILERS NO 4 & 5, PWR-4 & -5	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	49.1	LB/H	0		NOT AVAILABLE	
TX-0316	ANHEUSER-BUSH HOUSTON BREWERY	TX	07/13/1999 ACT	BOILER NO 6, PWR-6	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	30.3	LB/H	0		NOT AVAILABLE	
TX-0316	ANHEUSER-BUSH HOUSTON BREWERY	TX	07/13/1999 ACT	FLARE, BERS-1				Sulfur Dioxide (SO2)	NONE INDICATED	60.6	LB/H	0			
TX-0316	ANHEUSER-BUSH HOUSTON BREWERY	TX	07/13/1999 ACT	FIRE WATER PUMP ENGINE, FIRE-01	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED	0.64	LB/H	0			
TX-0316	ANHEUSER-BUSH HOUSTON BREWERY	TX	07/13/1999 ACT	BOILER NOS 4-6, PWR-4 TO -6, ANNUAL LIMITS ONLY	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	77	T/YR	0			THIS ENTRY LISTED ONLY THE TOTAL ANNUAL LIMITS FOR ALL THREE BOILERS COMBINED. EMISSION RATES WHEN BURNING FULL CAPACITY OF BIO-GAS. WHEN BIO-GAS FUELS THE BOILERS, THERE ARE NO EMISSIONS FROM THE FLARE AND WHEN BIOFUELS THE FLARE, BOILER EMISSIONS ARE 136.60 TPY NOX.
TX-0319	EXXON MOBIL BAYTOWN REFINERY	TX	09/10/1999 ACT	SCU 2 HOT OIL RECYCLE FURNACE, SCU2F703				Sulfur Dioxide (SO2)	NONE INDICATED	1.22	LB/H	0		NOT AVAILABLE	
TX-0319	EXXON MOBIL BAYTOWN REFINERY	TX	09/10/1999 ACT	FLUID CATALYTIC CRACKING UNIT 2, FCCU2				Sulfur Dioxide (SO2)	SCRUBBER	423	LB/H	0		NOT AVAILABLE	
TX-0319	EXXON MOBIL BAYTOWN REFINERY	TX	09/10/1999 ACT	FLUID CATALYTIC CRACKING UNIT 3, FCCU3				Sulfur Dioxide (SO2)	SCRUBBER	240	LB/H	0		NOT AVAILABLE	
TX-0319	EXXON MOBIL BAYTOWN REFINERY	TX	09/10/1999 ACT	BOILER HOUSE 6, BOILER 64, BH6B64				Sulfur Dioxide (SO2)	NONE INDICATED	12.76	LB/H	0		NOT AVAILABLE	
TX-0319	EXXON MOBIL BAYTOWN REFINERY	TX	09/10/1999 ACT	(2) DELAYED COKER FURNACE DCUF601, DCU F602				Sulfur Dioxide (SO2)	MINIMIZE THE H2S IN THE FUEL	7.89	LB/H	0		NOT AVAILABLE	

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TX-0319	EXXON MOBIL BAYTOWN REFINERY	TX	09/10/1999 ACT	SCU 2 INCINERATOR F702, SCU2F702				Sulfur Dioxide (SO2)	NONE INDICATED	0.52	LB/H	0			
TX-0319	EXXON MOBIL BAYTOWN REFINERY	TX	09/10/1999 ACT	FLEXSORB ADSORBER VENT SCU2T601				Sulfur, Total Reduced (TRS)	NONE INDICATED	4.76	LB/H	0			
TX-0320	ALON USA BIG SPRING REFINERY	TX	09/02/1999 ACT	(11) HEATERS	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	10.71	LB/H	0		NOT AVAILABLE	CAP FOR COMBINATION OF THE 11 HEATERS
TX-0327	FORMOSA PLASTICS TEXAS	TX	02/10/2000 ACT	WASTE HEAT BOILER, EP910				Sulfur Dioxide (SO2)	NONE INDICATED	0.03	LB/H	0		NOT AVAILABLE	
TX-0330	JACK COUNTY POWER PLANT	TX	03/14/2000 ACT	(2) GE-7241FA TURBINES, HRSG-1&-2	NAT GAS	520	MW	Sulfur Dioxide (SO2)	FIRING PIPELINE NAT GAS	10	LB/H	0			
TX-0330	JACK COUNTY POWER PLANT	TX	03/14/2000 ACT	AUXILIARY BOILER, B-1	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.02	LB/H	0		NOT AVAILABLE	
TX-0330	JACK COUNTY POWER PLANT	TX	03/14/2000 ACT	FIREWATER PUMP ENGINE, FWP-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.8	LB/H	0			
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	FIREWATER PUMP, 81				Sulfur Dioxide (SO2)	NONE INDICATED	0.26	LB/H	0			
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	SOLAR TURBINE & DUCT BURNER, 70	NATURAL GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.28	LB/H	0			
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	CONTINUOUS CATALYST REGENERATOR, 71				Sulfur Dioxide (SO2)	CAUSTIC SCRUBBER	0.12	LB/H	0			
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	REACTOR HEATER, 72	FUEL GAS			Sulfur Dioxide (SO2)	FIRING NAT GAS	0.38	LB/H	0		NOT AVAILABLE	
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	3 DIP TURBINES & 3 DUCT BURNERS, 74	NAT GAS			Sulfur Dioxide (SO2)	FIRING NAT GAS WITH S CONCENTRATION OF NO MORE THAN 15 PPMW.	0.46	LB/H	0			
TX-0333	MONT BELVIEU COMPLEX	TX	12/05/2000 ACT	FLARE, 76				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	TX	06/20/2000 ACT	SPRAY DRYER, FCC-21				Sulfur Dioxide (SO2)	NONE INDICATED	0.08	LB/H	0			
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	TX	06/20/2000 ACT	CALCINER, FCC-5A		37	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	TX	06/20/2000 ACT	SCR UNIT, FCC-75				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	TX	06/20/2000 ACT	FINAL PRODUCT CALCINER, FCC-74	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.02	LB/H	0			
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	TX	06/20/2000 ACT	STEAM BOILER, FCC-27	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.1	LB/H	0		NOT AVAILABLE	
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	TX	06/20/2000 ACT	DIESEL ENGINE, FCC-67	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED	0.14	LB/H	0			
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	TX	06/20/2000 ACT	FLASH DRYER, FCC-8				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	TX	06/20/2000 ACT	MOLSIEVE CALCINER, FCC-9				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	TX	06/20/2000 ACT	FLASH DRYER, FCC-10				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0334	AKZO NOBEL POLYMER CHEMICALS TRIGONOX 201	TX	06/20/2000 ACT	MOLSIEVE CALCINER, FCC-12				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0335	TRIGEANT CORPUS CHRISTI	TX	08/07/2000 ACT	PROCESS HEATER, STACK 3	NAT GAS			Sulfur Dioxide (SO2)	PIPELINE QUALITY, SWEET NAT GAS CONTAINING NO MORE THAN 0.25 GR H2S AND 5 GR S/100 DSCF.	0.79	LB/H	0		NOT AVAILABLE	NSPS SUBPART DC ALSO BASIS OF DETERMINATION.
TX-0335	TRIGEANT CORPUS CHRISTI	TX	08/07/2000 ACT	BOILER B, STACK 1B	NAT GAS			Sulfur Dioxide (SO2)	PIPELINE QUALITY, SWEET NAT GAS CONTAINING NO MORE THAN 0.25 GR H2S AND 5 GR S/100 DSCF.	0.03	LB/H	0		NOT AVAILABLE	NSPS SUBPART DC ALSO BASIS OF DETERMINATION.
TX-0335	TRIGEANT CORPUS CHRISTI	TX	08/07/2000 ACT	FLARE, FLARE	NAT GAS			Sulfur Dioxide (SO2)	CONT. IGNITION WITH TWO PILOTS, AN ULTRA-VIOLET FIRE-EYE FLAME MONITOR, KNOCK OUT POT, AND SEAL DRUM.	71.48	LB/H	0			
TX-0335	TRIGEANT CORPUS CHRISTI	TX	08/07/2000 ACT	BOILER A, STACK 1A	NAT GAS			Sulfur Dioxide (SO2)	PIPELINE QUALITY, SWEET NAT GAS CONTAINING NO MORE THAN 0.25 GR H2S AND 5 GR S/100 DSCF.	0.03	LB/H	0		NOT AVAILABLE	NSPS SUBPART DC ALSO BASIS OF DETERMINATION.
TX-0338	CHAMBERS PLANT	TX	05/23/2001 ACT	BOILER 3, 8736				Sulfur Dioxide (SO2)	NONE INDICATED	0.58	LB/H	0		NOT AVAILABLE	
TX-0338	CHAMBERS PLANT	TX	05/23/2001 ACT	(3) HEU PROCESS HEATERS, 8707-8709				Sulfur Dioxide (SO2)	NONE INDICATED	0.19	LB/H	0		NOT AVAILABLE	

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Combustion of Misc. Boilers, Furnaces, & Heaters

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0338	CHAMBERS PLANT	TX	05/23/2001 ACT	NS PROCESS HEATER, 8705				Sulfur Dioxide (SO2)	NONE INDICATED	0.47	LB/H	0		NOT AVAILABLE	
TX-0338	CHAMBERS PLANT	TX	05/23/2001 ACT	(2) BOILERS 1 & 2, 8729 & 8730				Sulfur Dioxide (SO2)	NONE INDICATED	3.87	LB/H	0		NOT AVAILABLE	
TX-0338	CHAMBERS PLANT	TX	05/23/2001 ACT	WATER STRIPPER HEATER, 8731				Sulfur Dioxide (SO2)	NONE INDICATED	0.04	LB/H	0		NOT AVAILABLE	
TX-0338	CHAMBERS PLANT	TX	05/23/2001 ACT	C/CF PROCESS HEATER, 8733				Sulfur Dioxide (SO2)	NONE INDICATED	4.06	LB/H	0		NOT AVAILABLE	
TX-0338	CHAMBERS PLANT	TX	05/23/2001 ACT	(3) LEF PROCESS HEATERS, 8701-8703				Sulfur Dioxide (SO2)	NONE INDICATED	4.06	LB/H	0		NOT AVAILABLE	
TX-0338	CHAMBERS PLANT	TX	05/23/2001 ACT	HF PROCESS HEATER, 8706				Sulfur Dioxide (SO2)	NONE INDICATED	0.31	LB/H	0		NOT AVAILABLE	
TX-0340	EXXON MOBIL BAYTOWN REFINERY	TX	04/13/2001 ACT	PROCESS HEATER, LSM HEATER F-101 DEPENTANIZER				Sulfur Dioxide (SO2)	FUEL SCRUBBING SYSTEM	7.01	LB/H	0			NSPS SUBPART J ALSO BASIS OF DETERMINATION
TX-0340	EXXON MOBIL BAYTOWN REFINERY	TX	04/13/2001 ACT	PROCESS HEATER, LSM HEATER F-361 TREAT GAS HEATER				Sulfur Dioxide (SO2)	FUEL SCRUBBING SYSTEM	10.58	LB/H	0			NSPS SUBPART J ALSO BASIS OF DETERMINATION
TX-0340	EXXON MOBIL BAYTOWN REFINERY	TX	04/13/2001 ACT	PROCESS LSM HEATER F-371 STABILIZER REBOILER				Sulfur Dioxide (SO2)	FUEL SCRUBBING SYSTEM	4.07	LB/H	0			NSPS SUBPART J ALSO BASIS OF DETERMINATION
TX-0340	EXXON MOBIL BAYTOWN REFINERY	TX	04/13/2001 ACT	PROCESS HEATER, LSM F-381 HOT OIL HEATER				Sulfur Dioxide (SO2)	FUEL SCRUBBING SYSTEM	6.34	LB/H	0			NSPS SUBPART J ALSO BASIS OF DETERMINATION
TX-0340	EXXON MOBIL BAYTOWN REFINERY	TX	04/13/2001 ACT	PROCESS HEATER, HF-4 HEATER F-401, HF4F401				Sulfur Dioxide (SO2)	FUEL SCRUBBING SYSTEM	12.21	LB/H	0			NSPS SUBPART J ALSO BASIS OF DETERMINATION
TX-0340	EXXON MOBIL BAYTOWN REFINERY	TX	04/13/2001 ACT	PROCESS HEATER, HF-4 HEATER F-403, HF4F403				Sulfur Dioxide (SO2)	FUEL SCRUBBING SYSTEM	6.11	LB/H	0			NSPS SUBPART J ALSO BASIS OF DETERMINATION
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	2ND STAGE HYDROTREATER FEED HEATER, J-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.08	LB/H	0		NOT AVAILABLE	
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	(2) HYDROTREATER REGENERATOR STACKS,DD-606&DDD-606				Sulfur Dioxide (SO2)	NONE INDICATED	45.8	LB/H	0			
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	NO. 1 OLEFINS FLARE, DM-1101				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	NO. 2 OLEFINS FLARE, DDM-3101				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	REGENERATION FURNACE, DB-201				Sulfur Dioxide (SO2)	NONE INDICATED	0.52	LB/H	0		NOT AVAILABLE	
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	REGENERATION HEATER, DB-601				Sulfur Dioxide (SO2)	NONE INDICATED	0.07	LB/H	0		NOT AVAILABLE	
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	REGENERATION HEATER, DDB-201				Sulfur Dioxide (SO2)	NONE INDICATED	0.5	LB/H	0		NOT AVAILABLE	
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	REGENERATION HEATER, DDB-601				Sulfur Dioxide (SO2)	NONE INDICATED	0.07	LB/H	0		NOT AVAILABLE	
TX-0347	CHOCOLATE BAYOU PLANT	TX	10/16/2001 ACT	FURNACE EMISSION CAPS FOR 30 EMISSION POINTS				Sulfur Dioxide (SO2)	NONE INDICATED	48	LB/H	0			ADDITIONAL CAPS: 53.66 LB/H, 11.75 T/YR FROM 3/31/04 TO 6/30/06, 61 37 LB/H, 13.44 T/YR AFTER 6/30/06
TX-0353	NAFTA REGION OLEFINS COMPLEX	TX	09/05/2001 ACT	BOILER, BLR	NAT GAS			Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMIT: THE NATURAL GAS STREAM SHALL CONTAIN LESS THAN 5 GR TOTAL SULFUR/100 DSCF.	3.25	LB/H	0		NOT AVAILABLE	
TX-0353	NAFTA REGION OLEFINS COMPLEX	TX	09/05/2001 ACT	HIGH PRESSURE FLARE, P-7	NAT GAS/ WASTE			Sulfur Dioxide (SO2)	NONE INDICATED	14.13	LB/H	0			
TX-0353	NAFTA REGION OLEFINS COMPLEX	TX	09/05/2001 ACT	LOW PRESSURE FLARE, P-6	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TRAIN 1- ETSH OR TBM PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TRAIN 1 - MESH PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES FOR LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TRAIN 2- MESH PRODUCTION FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SULFUR TRUCK, S-3				Sulfur Dioxide (SO2)	NONE INDICATED	0.07	LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	TANK TRUCK LOADING/UNLOADING FUGITIVES				Sulfur, Total Reduced (TRS)	SEE POLLUTANT NOTES. FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.03	LB/H	0			ALL LOADING LINES SHALL BE INSPECTED VISUALLY FOR POSSIBLE LEAK SITES BEFORE THE START OF ANY LOADING OPERATIONS. DAMAGED HOSES SHALL BE REPAIRED OR REPLACED BEFORE ANY LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADING OPERATIONS, ALL LOADING LINES (EXCEPT FOR MMP) SHALL BE PURGED WITH INERT GAS TO THE FLARE BEFORE ANY CONNECTIONS BETWEEN THE LOADING RACKS AND LOADED VESSELS ARE BROKEN. MMP RAILCAR LOADING WILL USE CLOSED LOOP VAPOR BALANCE SYSTEMS CONNECTED TO THE MMP STORAGE TANK OR THE SULFOX-TO. UPON COMPLETION OF MMP LOADING OPERATIONS THE LOADING LINE WILL BE PURGED INTO THE RAILCAR OR THE MMP STORAGE TANK. WHEN UNHOOKING THE RAILCAR FROM THE LOADING LINE, AN ACETIC ACID OR EQUIVALENT WASH WILL BE DONE AFTER EACH MMP LOADING. THE WASH MATERIAL WILL BE NEUTRALIZED AND MANAGED IN THE ON-SITE WASTEWATER SYSTEM. THE WASH MATERIAL TANK WILL VENT TO THE SULFOX-TO.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, SSM				Sulfur Dioxide (SO2)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18. SEE THE POLLUTANT NOTES.	2541.37	LB/H	0			TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW 5193 LB/H.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, SSM				Sulfur, Total Reduced (TRS)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18	24.27	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, TOTAL HOURLY AND ANNUAL				Sulfur Dioxide (SO2)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18. SEE POLLUTANT NOTES.	6207.34	LB/H	0			TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW 5193 LB/H.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Combustion of Misc. Boilers, Furnaces, & Heaters

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, TOTAL HOURLY AND ANNUAL				Sulfur, Total Reduced (TRS)	FOLLOW THE REQUIREMENTS OF 40 CFR 60.18	65.62	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	HEAT TRANSFER FLUID HEATER, H202	NATURAL GAS	31	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.02	LB/H	0.0006	LB/MMBTU	CALCULATED, USING THROUGHPUT	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	(2) SULFUR/METHANE HEATERS				Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.01	LB/H	0		NOT AVAILABLE	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	HEAT TRANSFER FLUID HEATER, H2202	NATURAL GAS	31	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 0.5 GR S/100 DSCF.	0.02	LB/H	0.0006	LB/MMBTU	CALCULATED USING THROUGHPUT	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	INCINERATOR				Sulfur Dioxide (SO2)	NONE INDICATED	139	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SULFUR STORAGE TANK, S-1				Sulfur Dioxide (SO2)	NONE INDICATED	0.86	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SULFUR PIT, S-2				Sulfur Dioxide (SO2)	NONE INDICATED	0.17	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	SOUR WATER STRIPPERS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, SSM		134.5	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	1156.47	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, SSM		134.5	MMBTU/H	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, TOTAL HOURLY AND ANNUAL		134.5	MMBTU/H	Sulfur Dioxide (SO2)	THE FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	1157.44	LB/H	0			WASTE GAS AND ATOMIZED LIQUID STREAMS FROM THE SULFOX UNITS SHALL BE ROUTED TO THE SULFOX TO. THE SULFOX TO SHALL DESTROY THE VOC STREAMS SENT TO IT AT A MINIMUM OF 99.9% OR AT A VOC OUTLET CONCENTRATION OF 10 PPMV.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, TOTAL HOURLY AND ANNUAL		134.5	MMBTU/H	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, STEADY STATE OPERATION				Sulfur Dioxide (SO2)	FOLLOW SPECIFICATIONS OF 40 CFR 60.18. SEE POLLUTANT NOTES.	3665.97	LB/H	0			TAC CHAPTER 112 REQUIREMENT: WHEN THE DISTRIBUTIVE CONTROL SYSTEM ENUNCIATES THAT EPN FLARE SO2 EMISSIONS EXCEED 5193 LB/H, THE FOLLOWING MEASURES SHALL BE TAKEN AS APPROPRIATE TO CONTROL TO THE EXTENT PRACTICABLE SO2 IMPACTS AT THE CAMS54 MONITOR: 1) PLANT PERSONNEL SHALL EVALUATE ALL RELEVANT METEORLOGICAL CONDITIONS TO DETERMINE WHETHER ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS IN THE VICINITY OF THE CAMS54 MONITOR; 2) PLANT PERSONNEL SHALL EVALUATE AMBIENT AIR QUALITY DATA PROVIDED BY THE CAMS54 MONITOR TO DETERMINE IF CURRENT SO2 CONCENTRATIONS ARE GREATER THAN 160 PPB; 3) IF IT IS DETERMINED THAT ADDITIONAL SO2 EMISSIONS FROM THE FLARE WOULD LIKELY RESULT IN INCREASED SO2 IMPACTS FROM THE FLARE AT THE CAMS54 MONITOR, AND THAT THE IMPACTS AT THE CAMS54 MONITOR ARE ABOVE 160 PPB, PLANT PERSONNNEL SHALL CURTAIL PERMITTED ACTIVITIES, AS APPROPRIATE, TO REDUCE SO2 EMISSIONS FROM THE FLARE TO THE MAXIMUM EXTENT PRACTICABLE, BUT TO AT LEAST AT OR BELOW 5193 LB/H.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	FLARE, STEADY STATE OPERATION				Sulfur, Total Reduced (TRS)	FOLLOW REQUIREMENTS OF 40 CFR 60.18	41.35	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	PRODUCT RECOVERY TOWER FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			

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TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	RAILCAR LOADING/UNLOADING FUGITIVES				Sulfur, Total Reduced (TRS)	SEE POLLUTANT NOTES.	0.03	LB/H	0			ALL LOADING LINES SHALL BE INSPECTED VISUALLY FOR POSSIBLE LEAK SITES BEFORE THE START OF ANY LOADING OPERATIONS. DAMAGED HOSES SHALL BE REPAIRED OR REPLACED BEFORE ANY LOADING OPERATIONS COMMENCE. UPON COMPLETION OF LOADING OPERATIONS, ALL LOADING LINES (EXCEPT FOR MMP) SHALL BE PURGED WITH INERT GAS TO THE FLARE BEFORE ANY CONNECTIONS BETWEEN THE LOADING RACKS AND LOADED VESSELS ARE BROKEN. MMP RAILCAR LOADING WILL USE CLOSED LOOP VAPOR BALANCE SYSTEMS CONNECTED TO THE MMP STORAGE TANK OR THE SULFOX-TO. UPON COMPLETION OF MMP LOADING OPERATIONS THE LOADING LINE WILL BE PURGED INTO THE RAILCAR OR THE MMP STORAGE TANK. WHEN UNHOOKING THE RAILCAR FROM THE LOADING LINE, AN ACETIC ACID OR EQUIVALENT WASH WILL BE DONE AFTER EACH MMP LOADING. THE WASH MATERIAL WILL BE NEUTRALIZED AND MANAGED IN THE ON-SITE WASTEWATER SYSTEM. THE WASH MATERIAL TANK WILL VENT TO THE SULFOX-TO.
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	DIMETHYL DISULFIDE AREA PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.06	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	(2) STEAM BOILERS, X-426A AND X-426B	NATURAL GAS	15.8	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	0.01	LB/H	0.0006	LB/MMBTU	EACH, CALCULATED USING THROUGHPUT	
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	RUNDOWN TANK FUGITIVES				Sulfur, Total Reduced (TRS)	MMP DAY STORAGE TANKS WILL VENT TO THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULF0X-TO. FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.11	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	STORAGE TANKS FUGITIVES				Sulfur, Total Reduced (TRS)	MMP DAY STORAGE TANKS WILL VENT TO THE MMP BULK STORAGE TANK WHICH WILL VENT TO SULF0X-TO. FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.15	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	DIMETHYL SULFIDE AREA PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PROCEDURES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.02	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	H2S PLANT PROCESS FUGITIVES				Sulfur, Total Reduced (TRS)	FOLLOW PRACTICES OF LEAK DETECTION, ISOLATION, AND REPAIR.	0.01	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, STEADY STATE SERVICE		134.5	MMBTU/H	Sulfur, Total Reduced (TRS)	NONE INDICATED	0.89	LB/H	0			
TX-0354	ATOFINA CHEMICALS INCORPORATED	TX	12/19/2002 ACT	THERMAL OXIDIZER, STEADY STATE SERVICE		134.5	MMBTU/H	Sulfur Dioxide (SO2)	FUEL GAS COMBUSTED IN EACH COMBUSTION EMISSION POINT NUMBER SHALL BE SWEET NATURAL GAS CONTAINING NO MORE THAN 5 GR S/100 DSCF.	4.21	LB/H	0			
TX-0359	LIMESTONE ELECTRIC GENERATING STATION	TX	05/23/2001 ACT	NO 2 SRU INCINERATOR, V-16				Sulfur Dioxide (SO2)	NONE INDICATED	10.48	LB/H	0		NOT AVAILABLE	
TX-0359	LIMESTONE ELECTRIC GENERATING STATION	TX	05/23/2001 ACT	FLUID CATALYTIC CRACK UNIT REGENERATOR VENT, V-20				Sulfur Dioxide (SO2)	NONE INDICATED	341	LB/H	100	PPMV	1 H AV	
TX-0359	LIMESTONE ELECTRIC GENERATING STATION	TX	05/23/2001 ACT	FCCU FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	3.46	LB/H	0			
TX-0359	LIMESTONE ELECTRIC GENERATING STATION	TX	05/23/2001 ACT	HCU FLARE, FL-4				Sulfur Dioxide (SO2)	NONE INDICATED	0.45	LB/H	0			
TX-0359	LIMESTONE ELECTRIC GENERATING STATION	TX	05/23/2001 ACT	BOILER, B-12	REFINERY FUEL			Sulfur Dioxide (SO2)	REFINERY FUEL GAS WITH HOURLY H2S CONTENT NOT TO EXCEED 0.10 GR/DSCF AND ANNUAL AVERAGE H2S NOT TO EXCEED 0.03 GR/DSCF	0.0376	LB/MMBTU	0.0376	LB/MMBTU		COMPLIANCE WITH THE SO2 EMISSION LIMIT SHALL BE BASED ON THE H2S CONTENT OF THE FUEL GAS, ASSUMING 100% CONVERSION OF H2S TO SO2.

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Combustion of Misc. Boilers, Furnaces, & Heaters

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	HOT AIR DRYERS ENTRY A				Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY SWEET NATURAL GAS.	0.01	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	RTP DRYER NO. 15				Sulfur Dioxide (SO2)	PIPELINE QUALITY SWEET NATURAL GAS	0.01	LB/H	0			THE FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	MAT LINE (DRYERS AND CLEANER)				Sulfur Dioxide (SO2)	PIPELINE QUALITY SWEET NATURAL GAS	0.01	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	HOT AIR DRYER NO. 45				Sulfur Dioxide (SO2)	PIPELINE QUALITY SWEET NATURAL GAS	0.01	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	BOILER NO. 2				Sulfur Dioxide (SO2)	NONE INDICATED	0.04	LB/H	0		NOT AVAILABLE	FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	EMERGENCY GENERATOR ENTRY A				Sulfur Dioxide (SO2)	NONE INDICATED	5.51	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	FURNACE NO. 5 DRYER NOS. 1-5				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			THE FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	FURNACE NO. 5 DRYER NO. 6				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	FURNACE NO. 5 FOREHEARTH MONITOR				Sulfur Dioxide (SO2)	NONE INDICATED	0.02	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	FURNACE NO. 5 CURING OVENS NOS. 1 & 2				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			THE FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	BOILER NO. 3				Sulfur Dioxide (SO2)	NONE INDICATED	0.03	LB/H	0		NOT AVAILABLE	FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	DIESEL GENERATOR	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED	0.93	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	FURNACE NO. 5				Sulfur Dioxide (SO2)	SCRUBBER AND AN ESP. ABATEMENT EQUIPMENT IS BYPASSED FOR MAINTENANCE NO MORE THAN 144 H/YR.	11.4	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	RTP DRYERS ENTRY B				Sulfur Dioxide (SO2)	USE OF PIPELINE QUALITY SWEET NATURAL GAS	0.01	LB/H	0			
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	FURNACE NO. 3				Sulfur Dioxide (SO2)	SCRUBBER AND AN ESP. ABATEMENT EQUIPMENT WILL BE BYPASSED FOR MAINTENANCE NO MORE THAN 144 H/YR.	6.66	LB/H	0			THE FACILITY NETTED OUT OF PSD REVIEW.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	FURNACE NO. 4				Sulfur Dioxide (SO2)	SCRUBBER AND AN ESP. ABATEMENT EQUIPMENT WILL BE BYPASSED FOR MAINTENANCE NO MORE THAN 286 H/YR.	9.03	LB/H	0			THE FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	FURNACES NO. 1				Sulfur Dioxide (SO2)	SCRUBBER FOLLOWED BY AN ESP. ABATEMENT EQUIPMENT WILL BE BYPASSED FOR MAINTENANCE NO MORE THAN 286 H/YR.	20.31	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	PROPANE FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.49	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	PROPANE EVAPORATOR NO 1				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	PROPANE EVAPORATOR ENTRY B				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			FACILIY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	FURNACE FOREHEARTH ENTRY A				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	FURNACE FOREHEARTH NO. 3				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	FURNACE FOREHEARTH NO. 4 AND RTP CHOPPER				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	FURNACE NO. 2				Sulfur Dioxide (SO2)	SCRUBBER AND AN ESP. ABATEMENT EQUIPMENT WILL BE BYPASSED FOR MAINTENANCE NO MORE THAN 286 H/YR.	20.31	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	HOT AIR DRYER NO. 98				Sulfur Dioxide (SO2)	PIPELINE QUALITY SWEET NATURAL GAS	0.01	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	RTP DRYERS ENTRY A				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2.
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	POST CURING OVEN NO. 1				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2

Summary of SO_2 Control Determination per EPA's RACT/BACT/LAER Database for Combustion of Misc. Boilers, Furnaces, & Heaters

RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0362	VETROTEX AMERICA	TX	03/22/2000 ACT	POST CURING OVENS NOS. 2 & 3				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			FACILITY NETTED OUT OF PSD REVIEW FOR SO2
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FOREHEARTH MONITOR, FURNACE NO 5				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	CURING OVEN NO 1 & 2 FURNACE NO 5				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(5) HOT AIR DRYERS, FURNACE NO 5				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	HOT AIR DRYER NO 6, FURNACE 5				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(6) HOT AIR DRYER NO 31, 32, 33, 34, 35, 36				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	RTP DRYER NO 15				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	MAT LINE (DRYERS & CLEANER)				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	HOT AIR DRYER NO 45				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	BOILER NO. 2	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.04	LB/H	0		NOT AVAILABLE	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(2) EMERGENCY GENERATORS NO. 1 & 2	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED	5.51	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	PROPANE FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.49	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	PROPANE EVAPORATOR NO. 1				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(3) PROPANE EVAPORATORS NO 2, 3, 4				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(2) FURNACE FOREHEARTHS NO 1 & 2				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(2) RTP DRYERS NO 12 & 13				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(3) RTP DRYERS NO 16, 17, 18				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	BOILER NO 3	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.03	LB/H	0		NOT AVAILABLE	
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	DIESEL GENERATOR	DIESEL			Sulfur Dioxide (SO2)	NONE INDICATED	0.93	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FURNACE NO 5	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	11.4	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FURNACE FOREHEARTH NO 3				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FURNACE NO 4 FOREHEARTH & RTP CHOPPER				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	HOT AIR DRYER NO 98				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(2) RTP DRYERS 10 & 11				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	POST CURING OVEN NO 1				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	(2) POST CURING OVENS NO 2 & 3				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FURNACE NO 3	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	6.66	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FURNACE NO. 1	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	20.31	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FURNACE NO 2	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	20.31	LB/H	0			
TX-0363	SAINT-GOBAIN VETROTEX AMERICA	TX	11/13/2000 ACT	FURNACE NO 4	NAT GAS			Sulfur Dioxide (SO2)	ESP & SCRUBBER	9.03	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	PACKAGE BOILER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE	
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	STANDBY INCINERATOR				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	PACKAGE BOILER BO-4	NAT GAS	60	MMBTU/H	Sulfur Dioxide (SO2)	NONE INDICATED	0.95	LB/H	0 02	LB/MMBTU	CALCULATED USING THROUGHPUT	
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	REGENERATIVE GAS HEATER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE	

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	MONUMENT NO. 2 FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	WASTE HEAT BOILER	NAT GAS			Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE	
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	TRAIN NO. 8 FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0378	LA PORTE POLYPROPYLENE PLANT	TX	11/05/2001 ACT	ALKYL FLARE				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0			
TX-0380	SYNTHESIS GAS UNIT	TX	06/01/2001 ACT	(2) AIR PREHEATERS 1106 & 1206, F1106SGU &F1206SGU				Sulfur Dioxide (SO2)	NONE INDICATED	0.01	LB/H	0		NOT AVAILABLE	
TX-0380	SYNTHESIS GAS UNIT	TX	06/01/2001 ACT	FLARE, FS28	SYNGAS			Sulfur Dioxide (SO2)	NONE INDICATED	3337.57	LB/H	0			
TX-0403	LOUISIANA-PACIFIC CORPORATION	TX	07/06/1999 ACT	THERMAL OIL HEATER, BYPASS STACK, (2)	WOOD/NATURAL GAS			Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.02	LB/H	0		SEE NOTE	LIMIT APPLIES WHEN BURNING NATURAL GAS ONLY. LIMIT AS LBS/MMBTU NOT AVAILABLE.
TX-0403	LOUISIANA-PACIFIC CORPORATION	TX	07/06/1999 ACT	WOOD DRYERS, (5)	WOOD WASTE	1636250	sqf/d	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	1.09	LB/H	0			THE EMISSION POINT FOR THIS PROCESS IS THE RTO.
TX-0403	LOUISIANA-PACIFIC CORPORATION	TX	07/06/1999 ACT	PRESS		1636250	sqf/D	Sulfur Dioxide (SO2)	LOW SULFUR FUEL	0.01	LB/H	0			THE LIMIT CORRESPONDS TO THE EMISSIONS FROM RTO.
TX-0415	PORT ARTHUR REFINERY	TX	03/04/1999 ACT	FLARE	WASTE GAS			Sulfur Dioxide (SO2)	REFINERY GAS LIMIT: 160 PPMV HYDROGEN SULFIDE	0.03	LB/H	0			
TX-0415	PORT ARTHUR REFINERY	TX	03/04/1999 ACT	CRACKING FURNACE, RECYCLE ETHANE	REFINERY GAS	302	mmbtu/h	Sulfur Dioxide (SO2)	REFINERY GAS LIMIT: 160 PPMV HYDROGEN SULFIDE	1.12	LB/H	0.0037	LB/MMBTU	CALCULATED	
TX-0415	PORT ARTHUR REFINERY	TX	03/04/1999 ACT	CRACKING HEATER, FRESH FEED, (8)	REFINERY GAS	441.7	mmbtu/h	Sulfur Dioxide (SO2)	REFINERY GAS LIMIT: 160 PPMV HYDROGEN SULFIDE	1.61	LB/H	0.0036	LB/MMBTU	CALCULATED	
TX-0415	PORT ARTHUR REFINERY	TX	03/04/1999 ACT	HEATER, DP REACTOR FEED	REFINERY GAS	62 58	mmbtu/h	Sulfur Dioxide (SO2)	REFINERY GAS LIMIT: 160 PPMV HYDROGEN SULFIDE	0.22	LB/H	0.0035	LB/MMBTU	CALCULATED	
TX-0415	PORT ARTHUR REFINERY	TX	03/04/1999 ACT	HEATER, DP REACTOR REGENERATION	REFINERY GAS	21 56	mmbtu/h	Sulfur Dioxide (SO2)	REFINERY GAS LIMIT: 160 PPMV HYDROGEN SULFIDE	0.07	LB/H	0.0032	LB/MMBTU	CALCULATED	
TX-0415	PORT ARTHUR REFINERY	TX	03/04/1999 ACT	BOILER, AUXILIARY	REFINERY GAS	416	mmbtu/h	Sulfur Dioxide (SO2)	REFINERY GAS LIMIT: 160 PPMV HYDROGEN SULFIDE	1.44	LB/H	0.0035	LB/MMBTU	CALCULATED	
TX-0415	PORT ARTHUR REFINERY	TX	03/04/1999 ACT	HEATER, CONDENSATE SPLITTER	REFINERGY GAS	211 07	mmbtu/h	Sulfur Dioxide (SO2)	REFINERY GAS LIMIT: 160 PPMV HYDROGEN SULFIDE	0.73	LB/H	0.0035	LB/MMBTU		
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	TX	12/05/2002 ACT	HEATER, STARTUP, MALEIC ANHYDRIDE REACTOR	NATURAL GAS	160.7	mmbtu/h	Sulfur Dioxide (SO2)	PIPELINE QUALITY NATURAL GAS < 2.0 GR S PER 1000 DSCF	0.64	LB/H	0.004	LB/MMBTU	CALCULATED	
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	TX	12/05/2002 ACT	FLARE, BDO UNIT	NATURAL GAS			Sulfur Dioxide (SO2)		0.05	LB/H	0			
TX-0422	BP TEXAS CITY CHEMICAL PLANT B	TX	12/05/2002 ACT	BOILER, SCRUBBER OFF-GAS				Sulfur Oxides (SOx)		7.75	LB/H	0		SEE NOTE	STANDARDIZED EMISSION LIMIT UNAVAILABLE.
TX-0446	JASPER ORIENTED STRANDBOARD MILL	TX	02/09/2004 ACT	THERMAL OIL HEATER BYPASS				Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0446	JASPER ORIENTED STRANDBOARD MILL	TX	02/09/2004 ACT	EMERGENCY GENERATOR				Sulfur Dioxide (SO2)		3.24	LB/H	0			
TX-0446	JASPER ORIENTED STRANDBOARD MILL	TX	02/09/2004 ACT	FIRE WATER PUMP				Sulfur Dioxide (SO2)		1.18	LB/H	0			
TX-0446	JASPER ORIENTED STRANDBOARD MILL	TX	02/09/2004 ACT	DRYER RTOS				Sulfur Dioxide (SO2)		2.18	LB/H	0			
TX-0446	JASPER ORIENTED STRANDBOARD MILL	TX	02/09/2004 ACT	PRESS RTO				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0446	JASPER ORIENTED STRANDBOARD MILL	TX	02/09/2004 ACT	PRESS BYPASS				Sulfur Dioxide (SO2)		0.33	LB/H	0			
TX-0447	CARHAGE ORIENTED STRANDBOARD MILL	TX	03/16/2004 ACT	DRYER RTOS (2)				Sulfur Dioxide (SO2)		2.68	LB/H	0			
TX-0447	CARHAGE ORIENTED STRANDBOARD MILL	TX	03/16/2004 ACT	PRESS RTO				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0447	CARHAGE ORIENTED STRANDBOARD MILL	TX	03/16/2004 ACT	THERMAL OIL HEATER BYPASS				Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0447	CARHAGE ORIENTED STRANDBOARD MILL	TX	03/16/2004 ACT	EMERGENCY GENERATOR				Sulfur Dioxide (SO2)		3.24	LB/H	0			
TX-0447	CARHAGE ORIENTED STRANDBOARD MILL	TX	03/16/2004 ACT	FIRE WATER PUMP				Sulfur Dioxide (SO2)		1.23	LB/H	0			
TX-0448	SID RICHARDSON CARBON BORGER PLANT	TX	03/29/2004 ACT	BOILER STACK, PLANT 1 DRYER, AND PLANT 2 DRYER				Sulfur Dioxide (SO2)	EMISSIONS OF SO2 WILL BE MINIMIZED BY RESTRICTING THE SULFUR CONTENT OF THE CARBON BLACK FEEDSTOCK OIL TO 3 0% ON AN ANNUAL BASIS AND THE USE OF PIPELINE QUALITY SWEET NATURAL GAS AS THE PRIMARY REACTOR FUEL	3921.6	LB/H	0			
TX-0448	SID RICHARDSON CARBON BORGER PLANT	TX	03/29/2004 ACT	OIL PREHEATER STACK (3)				Sulfur Dioxide (SO2)		0.01	LB/H	0			

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RBLCID	FACILITY NAME	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	STANDARD EMISSION LIMIT	STANDARD EMISSION LIMIT UNIT	STANDARD LIMIT AVERAGE TIME CONDITION	POLLUTANT COMPLIANCE NOTES
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	TX	03/18/2005 ACT	PILOT PLANT FLARE				Sulfur Dioxide (SO2)		435.27	LB/H	0			
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	TX	03/18/2005 ACT	PROCESS BAG FILTER				Sulfur Dioxide (SO2)		0.15	LB/H	0			
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	TX	03/18/2005 ACT	FEED STOCK OIL PRE HEATER	NATURAL GAS, FUEL OIL, OR FLUE GAS	0.9	MMBTU/H	Sulfur Dioxide (SO2)		0 001	LB/H	0			
TX-0464	CONTINENTAL CARBON SUNRAY PLANT	TX	03/18/2005 ACT	OXYGEN PRE HEATER	NATURAL GAS			Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	COOPER-BESSEMER ENGINE 3105 HP		3105	HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.26	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	HOT OIL HEATER		32.5	MMBTU/H	Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	FLARES (2)				Sulfur Dioxide (SO2)		50.48	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	HP TEG FIREBOX				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	COOPER-BESSEMER ENGINE		2400	HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.36	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	CLARK ENGINE (2)		2000	HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.31	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	INGERSOLL-RAND ENGINE		440	HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.7	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	HOT OIL HEATER		12	MMBTU/H	Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	INGERSOLL-RAND ENGINE 1330 HP		1330	HP	Sulfur Dioxide (SO2)	LEAN COMBUSTION	0.33	LB/H	0			
TX-0465	SALT CREEK GAS PLANT	TX	01/31/2003 ACT	GLYCOL REBOILER		2.5	MMBUT/H	Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	PYROLYSIS FURNACE (1010B)	FUEL GAS	250	MMBtu/H	Sulfur Dioxide (SO2)		0.41	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	PYROLYSIS FURNACES (1001-1008, 1009 B)	FUEL GAS	250	MMBtu/h	Sulfur Dioxide (SO2)		0.38	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	REBOILER (1 AND 2)	FUEL GAS	250	MMBtu	Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	FLARE				Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	DIESEL EMERGENCY GENERATOR				Sulfur Dioxide (SO2)		2.06	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	PYROLYSIS FURNACE (1054-1056)	FUEL GAS	250	mmbtu/h	Sulfur Dioxide (SO2)		0.38	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	PYROLYSIS FURNACE (1057-1062, 1091)	FUEL GAS	250	MMBTU/h	Sulfur Dioxide (SO2)		0.38	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	PYROLYSIS FURNACE (N1011-1012)		250	MMBTU/H	Sulfur Dioxide (SO2)		0.41	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	FLARE (1067)				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	FLARE (1087)				Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	DIESEL EMERGENCY GENERATOR (N7900LJD)	DIESEL			Sulfur Dioxide (SO2)		1.85	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	REGENERATION HEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	SECOND STAGE FEED HEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	FLARE (8003B)				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0476	CONOCOPHILLIPS BORGER REFINERY	TX	04/08/2005 ACT	VACUUM UNIT 51 AND COKER UNIT 50				Sulfur Dioxide (SO2)	LIMIT H2S IN FUEL GAS	6681	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	DHT STRIPPER REBOILER	REFINERY FUEL GAS			Sulfur Dioxide (SO2)		1.9	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	COKER HEATER		291	MMBUT/H	Sulfur Dioxide (SO2)		6.6	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER		62	MMBTU/H	Sulfur Dioxide (SO2)		1.4	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	ACID GAS FLARE				Sulfur Dioxide (SO2)		0.2	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	NO.3 BOILER	REFINERY FUEL GAS	99	MMBTU/H	Sulfur Dioxide (SO2)		2.2	LB/H	0			

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TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	TAIL GAS INCINERATOR		100	MMBTU/H	Sulfur Dioxide (SO2)		22.4	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER REBOILER HEATER	REFINERY FUEL GAS	82	MMBTU/H	Sulfur Dioxide (SO2)		5.7	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	SOUR WATER STRIPPER FLARE				Sulfur Dioxide (SO2)		0.19	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	FLARE-COKE DRUM BLOWDOWN				Sulfur Dioxide (SO2)		1056	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	DHT CHARGER HEATER				Sulfur Dioxide (SO2)		2.1	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	L-AREA GAS TURBINE	NATURAL GAS			Sulfur Dioxide (SO2)		0.03	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N5/6 FLARE				Sulfur Dioxide (SO2)		0.11	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N-3 BACKUP INSTRUMENT AIR COMPRESSOR				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N7/8 PREHEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N3/7 FEED AND EXIT GAS FLARE				Sulfur Dioxide (SO2)		0.11	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N-3,4 PREHEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N-5/6 PREHEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0493	DOW CHEMICAL PLANT B AND OYSTER CREEK LIGHT HYDROCARBONS PLA	TX	07/05/2005 ACT	B-7200 UNIT	HYDROCARBONS			Sulfur Dioxide (SO2)		201	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	TURBINE EXHAUST DUCT BURNER (3)	NATURAL GAS			Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	POWER STEAM BOILER	NATURAL GAS	93	MMBTU/H	Sulfur Dioxide (SO2)		0.05	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	TREATED GAS COMPRESSOR ENGINE STACK WITH CATALYTIC CONVERTER WAUKESHA L-7042GSI		875	HP	Sulfur Dioxide (SO2)		0.46	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	TAIL GAS INCINERATOR STACK				Sulfur Dioxide (SO2)		350	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	BOTTOM HEATERS (2)		15	MMBTU/H	Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	ALLISON 501KB GAS TURBINE GENERATOR	NATURAL GAS			Sulfur Dioxide (SO2)		0.67	LB/H	0			
TX-0604	GOLDSMITH GAS PLANT	TX	11/03/2011 ACT	Tail Gas Incinerator	Natural Gas	0		Sulfur Dioxide (SO2)		1521.8	T/YR	0			
VA-0299	UNITED STATES GYPSUM COMPANY	VA	06/19/2006 ACT	BURNERS, (2) CALCINING HAMMER MILL	DISTILLATE OIL	60	MMBTU/H	Sulfur Dioxide (SO2)		3.1	LB/H	0			EMISSION LIMITS ARE FOR ONE OF TWO BURNERS
VA-0299	UNITED STATES GYPSUM COMPANY	VA	06/19/2006 ACT	DRYING KILN, WET & DRY ZONE BURNERS	DISTILLATE OIL	100	MMBTU/H	Sulfur Dioxide (SO2)		5.1	LB/H	0			EMISSION LIMITS ARE FOR ONE OF TWO BURNERS
WI-0202	COMBINED LOCKS MILL	WI	08/13/2003 ACT	OFF-MACHINE COATER, DRYER (P51 / S51)	NATURAL GAS	1256	T/D	Sulfur Dioxide (SO2)	USE NATURAL GAS	0		0		see note	BACT for this pollutant is use of natural gas, no emission rate limits
WI-0212	SENA - NIAGARA MILL	WI	07/15/2005 ACT	PROCESS HEATER PAPER MACHINE P51 DRYER	NATURAL GAS	35.3	MMBTU/H	Sulfur Dioxide (SO2)	NATURAL GAS AS FUEL	0		0			NO EMISSION RATE LIMITS, BACT IS POLLUTION PREVENTION.

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FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	01/10/2007 ACT	COMBINED CYCLE COMBUSTION GAS TURBINES - 6 UNITS	NATURAL GAS	2333	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUELS	2	GS/100 SCF GAS	0			SULFUR FUEL SPECIFICATIONS COMBINED WITH THE EFFICIENT COMBUSTION DESIGN AND OPERATION OF EACH GAS TURBINE REPRESENTS (BACT) FOR PM/PM10 EMISSIONS.
FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	01/10/2007 ACT	TWO 99.8 MMBTU/H GAS-FUELED AUXILIARY BOILERS	NATURAL GAS	99.8	MMBTU/H	Sulfur Dioxide (SO2)		2	GS/100 SCF GAS	0			
FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	01/10/2007 ACT	TWO GAS-FUELED 10 MMBTU/H PROCESS HEATERS	NATURAL GAS	10	MMBTU/H	Sulfur Dioxide (SO2)		2	GS/100 SCF GAS	0			
FL-0286	FPL WEST COUNTY ENERGY CENTER	FL	01/10/2007 ACT	FOUR 2250 KW LIQUID FUEL EMERGENCY GENERATORS	FUEL OIL			Sulfur Dioxide (SO2)		0.0015	% S FUEL OIL	0			
GA-0145	CARBO CERAMICS INC. - MILLEN FACILITY	GA	04/06/2012 ACT	CALCINER	NATURAL GAS	60	MMBTU/H	Sulfur Dioxide (SO2)	WET SCRUBBER, USE OF NATURAL GAS AND PROPANT	90	% CONTROL BY WEIGHT	0			TEST METHOD: METHOD 6 OR 6C 40 CFR 60,SUBPART UUU
GA-0145	CARBO CERAMICS INC. - MILLEN FACILITY	GA	04/06/2012 ACT	EMERGENCY DIESEL GENERATOR	DIESEL	20.2	MMBTU/H	Sulfur Dioxide (SO2)		15	PPM SULFUR IN FUEL	0			40 CFR 60, SUBPART IIII 40 CFR 63, SUBPART ZZZZ
LA-0137	NORTH BEND CARBON BLACK PLANT	LA	05/22/2002 ACT	DRYER STACK (EMISSION POINT 59)	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK TO 3 RUBBER GRADE UNITS <= 3% BY WEIGHT; SULFUR CONTENT OF FEEDSTOCK TO 5 INDUSTRIAL GRADE UNITS <= 1 5% BY WEIGHT.	580.25	LB/H	0			*AS IMPOSED BY PSD-LA-580(M-4), ISSUED JULY 11, 2005. ANNUAL SO2 LIMIT FOR THE DRYER STACK (59), STEAM BOILER (62), MAIN COMBUSTION STACK (81), DRYER STACK (84), AND NEW TAIL GAS FLARE (123) ESTABLISHED AT 15,095.70 TPY (ANNUAL MAXIMUM). PSD-LA-580(M-3) SET LIMITS FOR THE DRYER STACK AT 389 26 LB/HR (HOURLY MAXIMUM) & 1704 94 TPY (ANNUAL MAXIMUM).
LA-0137	NORTH BEND CARBON BLACK PLANT	LA	05/22/2002 ACT	STEAM BOILER	FEEDSTOCK OIL	15	MMBTU/H	Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK TO 3 RUBBER GRADE UNITS <= 3% BY WEIGHT; SULFUR CONTENT OF FEEDSTOCK TO 5 INDUSTRIAL GRADE UNITS <= 1 5% BY WEIGHT.	166.17	LB/H	0			*AS IMPOSED BY PSD-LA-580(M-4), ISSUED JULY 11, 2005. ANNUAL SO2 LIMIT FOR THE DRYER STACK (59), STEAM BOILER (62), MAIN COMBUSTION STACK (81), DRYER STACK (84), AND NEW TAIL GAS FLARE (123) ESTABLISHED AT 15,095.70 TPY (ANNUAL MAXIMUM). PSD-LA-580(M-3) SET LIMITS FOR THE STEAM BOILER AT 97 01 LB/HR (HOURLY MAXIMUM) & 424.91 TPY (ANNUAL MAXIMUM).
LA-0137	NORTH BEND CARBON BLACK PLANT	LA	05/22/2002 ACT	MAIN COMBUSTION STACK	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK TO 3 RUBBER GRADE UNITS <= 3% BY WEIGHT; SULFUR CONTENT OF FEEDSTOCK TO 5 INDUSTRIAL GRADE UNITS <= 1 5% BY WEIGHT.	2437.79	LB/H	0			*AS IMPOSED BY PSD-LA-580(M-4), ISSUED JULY 11, 2005. ANNUAL SO2 LIMIT FOR THE DRYER STACK (59), STEAM BOILER (62), MAIN COMBUSTION STACK (81), DRYER STACK (84), AND NEW TAIL GAS FLARE (123) ESTABLISHED AT 15,095.70 TPY (ANNUAL MAXIMUM). PSD-LA-580(M-3) SET LIMITS FOR THE MAIN COMBUSTION STACK AT 2633.15 LB/HR (HOURLY MAXIMUM) & 11,533.21 TPY (ANNUAL MAXIMUM).
LA-0137	NORTH BEND CARBON BLACK PLANT	LA	05/22/2002 ACT	DRYER STACK (EMISSION POINT 84)	FEEDSTOCK OIL			Sulfur Dioxide (SO2)	SULFUR CONTENT OF FEEDSTOCK TO 3 RUBBER GRADE UNITS <= 3% BY WEIGHT; SULFUR CONTENT OF FEEDSTOCK TO 5 INDUSTRIAL GRADE UNITS <= 1 5% BY WEIGHT.	263.12	LB/H	0			*AS IMPOSED BY PSD-LA-580(M-4), ISSUED JULY 11, 2005. ANNUAL SO2 LIMIT FOR THE DRYER STACK (59), STEAM BOILER (62), MAIN COMBUSTION STACK (81), DRYER STACK (84), AND NEW TAIL GAS FLARE (123) ESTABLISHED AT 15,095.70 TPY (ANNUAL MAXIMUM). PSD-LA-580(M-3) SET LIMITS FOR THE DRYER STACK AT 327 07 LB/HR (HOURLY MAXIMUM) & 1432 55 TPY (ANNUAL MAXIMUM).
MI-0303	MIDLAND COGENERATION	MI	07/26/2001 ACT	DUCT BURNERS, 2 EACH	NATURAL GAS	400	MMBTU/H	Sulfur Dioxide (SO2)	30 DAY ROLLING AVERAGE. WILL FIRE ONLY PIPELINE QUALITY NATURAL GAS. NOT OVER 3100 HOURS/YR.	0.8	LB/MMBTU	0.8	LB/MMBTU		
OH-0277	DAIMLER CHRYSLER CORPORATION BODY SHOP	OH	08/31/2004 ACT	HOT WATER BOILER, W/ NATURAL GAS, 2 UNITS	NATURAL GAS	50	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, EQUAL TO OR LESS THAN 0 5 % SULFUR	0.03	LB/H	0.0006	LB/MMBTU	FROM NATURAL GAS	LB/H LIMIT FOR EACH BOILER. *T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL COMBUSTION UNITS NOT TO EXCEED 8 99 T/ROLLING 12-MO.
OH-0277	DAIMLER CHRYSLER CORPORATION BODY SHOP	OH	08/31/2004 ACT	AIR SUPPLY MAKE UP UNITS (40 UNITS) AND BODY WASHERS (2 UNITS)	NATURAL GAS	90	MMBTU/H	Sulfur Dioxide (SO2)		0.06	LB/H	0.0006	LB/MMBTU		*T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL COMBUSTION UNITS NOT TO EXCEED 8 99 T/ROLLING 12-MO.
OH-0277	DAIMLER CHRYSLER CORPORATION BODY SHOP	OH	08/31/2004 ACT	HOT WATER BOILER, W/ #2 FUEL OIL, 2 UNITS	NUMBER 2 FUEL OIL	50	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, EQUAL TO OR LESS THAN 0 5 % SULFUR	26	LB/H	0 51	LB/MMBTU	FROM #2 FUEL OIL	LB/H LIMIT FOR EACH BOILER. *T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL COMBUSTION UNITS NOT TO EXCEED 8 99 T/ROLLING 12-MO.
OH-0278	DAIMLER CHRYSLER CORPORATION ROLLING CHASSIS	OH	08/31/2004 ACT	AIR SUPPLY MAKE UP UNITS (20 UNITS)	NATURAL GAS	50	MMBTU/H	Sulfur Dioxide (SO2)		0.03	LB/H	0.0006	LB/MMBTU		
OH-0279	DAIMLER CHRYSLER CORPORATION ASSEMBLY PLANT	OH	09/02/2004 ACT	HOT WATER BOILER, W/ NATURAL GAS, 2 UNITS	NATURAL GAS	50	MMBTU/H	Sulfur Dioxide (SO2)		0.03	LB/H	0.0006	LB/MMBTU	FROM NATURAL GAS	LB/H LIMIT FOR EACH BOILER. *T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN THE 2 BOILERS, THE AIR SUPPLY MAKE UP UNITS, AND 4 FINAL REPAIR OVENS NOT TO EXCEED 9 01 T/ROLLING 12-MO.

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OH-0279	DAIMLER CHRYSLER CORPORATION ASSEMBLY PLANT	OH	09/02/2004 ACT	HOT WATER BOILER, W/ #2 FUEL OIL	#2 FUEL OIL	50	MMBTU/H	Sulfur Dioxide (SO2)	LOW SULFUR FUEL, EQUAL TO OR LESS THAN 0 5 % SULFUR	26	LB/H	0 51	LB/MMBTU	FROM #2 FUEL OIL	LB/H LIMIT FOR EACH BOILER. *T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN THE 2 BOILERS, THE AIR SUPPLY MAKE UP UNITS, AND 4 FINAL REPAIR OVENS NOT TO EXCEED 9 01 T/ROLLING 12-MO.
OH-0279	DAIMLER CHRYSLER CORPORATION ASSEMBLY PLANT	OH	09/02/2004 ACT	AIR SUPPLY MAKE UP UNITS	NATURAL GAS	95	MMBTU/H	Sulfur Dioxide (SO2)		0.06	LB/H	0.0006	LB/MMBTU		*T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN THE 2 BOILERS, THE AIR SUPPLY MAKE UP UNITS, AND 4 FINAL REPAIR OVENS NOT TO EXCEED 9.01 T/ROLLING 12-MO.
OH-0279	DAIMLER CHRYSLER CORPORATION ASSEMBLY PLANT	OH	09/02/2004 ACT	NAT GAS DRYING OVENS,4,FOR 4 AUTOMOTIVE OFF-LINE REPAIR BOOTHS	NATURAL GAS	5	MMBTU/H EACH	Sulfur Dioxide (SO2)		0.01	LB/H	0			LB/H & T/YR LIMITS ARE FOR EACH DRYING OVEN FROM COMBUSTION OF NATURAL GAS, AT 5 MMBTU/H EACH. THE COMBINED SO2 EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN THE 2 BOILERS, THE AIR SUPPLY MAKE UP UNITS, AND 4 FINAL REPAIR OVENS IS NOT TO EXCEED 9.01 T/ROLLING 12-MO.
OH-0280	DAIMLER CHRYSLER CORPORATION PAINT SHOP	OH	09/02/2004 ACT	HOT WATER BOILER, W/ NATURAL GAS, 2 UNITS	NATURAL GAS	50	MMBTU/H	Sulfur Dioxide (SO2)		0.03	LB/H	0.0006	LB/MMBTU	FROM NATURAL GAS	LB/H LIMIT FOR EACH BOILER. *T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19 T/ROLLING 12-MO.
OH-0280	DAIMLER CHRYSLER CORPORATION PAINT SHOP	OH	09/02/2004 ACT	AIR SUPPLY MAKEUP UNITS (30 UNITS)	NATURAL GAS	20	MMBTU/H	Sulfur Dioxide (SO2)		0.02	LB/H	0.0006	LB/MMBTU		LB/H LIMIT FOR EACH UNIT. *T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19 T/ROLLING 12-MO.
OH-0280	DAIMLER CHRYSLER CORPORATION PAINT SHOP	OH	09/02/2004 ACT	ELECTRODEPOSITION		200064	JOBS/ROLLING 12-MO	Sulfur Dioxide (SO2)		0.01	LB/H	0.0006	LB/MMBTU		*T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19 T/ROLLING 12-MO.
OH-0280	DAIMLER CHRYSLER CORPORATION PAINT SHOP	OH	09/02/2004 ACT	ELECTRODEPOSITION OVEN	NATURAL GAS	29.6	MMBTU/H	Sulfur Dioxide (SO2)		0.02	LB/H	0.0006	LB/MMBTU		*T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19T/ROLLING 12-MO.
OH-0280	DAIMLER CHRYSLER CORPORATION PAINT SHOP	OH	09/02/2004 ACT	AIR SUPPLY MAKE UP UNITS (17 UNITS)	NATURAL GAS	10	MMBTU/H	Sulfur Dioxide (SO2)		0.04	LB/H	0.0006	LB/MMBTU		*T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19 T/ROLLING 12-MO.
OH-0280	DAIMLER CHRYSLER CORPORATION PAINT SHOP	OH	09/02/2004 ACT	ELECTROSTATIC POWDER PRIMER SPRAY BOOTH OVEN	NATURAL GAS	37.3	MMBTU/H	Sulfur Dioxide (SO2)		0.03	LB/H	0.0006	LB/MMBTU		*T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19 T/ROLLING 12-MO.
OH-0280	DAIMLER CHRYSLER CORPORATION PAINT SHOP	OH	09/02/2004 ACT	TOPCOAT BOOTHS (TWO) FOR BASECOAT AND CLEARCOAT		200064	JOBS/ROLLING 12-MO	Sulfur Dioxide (SO2)		0.01	LB/H	0.0006	LB/MMBTU		EMISSIONS FROM THERMAL OXIDIZER CONTROL. *T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19 T/ROLLING 12-MO.
OH-0280	DAIMLER CHRYSLER CORPORATION PAINT SHOP	OH	09/02/2004 ACT	TOPCOAT DRYING OVEN	NATURAL GAS	66	MMBTU/H	Sulfur Dioxide (SO2)		0.04	LB/H	0.0006	LB/MMBTU		*T/ROLLING 12-MO IS THE COMBINED EMISSIONS FROM COMBUSTION OF FUEL OIL AND NATURAL GAS IN ALL UNITS IN PERMIT, NOT TO EXCEED 9.19 T/ROLLING 12-MO.
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	OH	05/03/2007 ACT	BOILER (2), NATURAL GAS	NATURAL GAS	20.4	MMBTU/H	Sulfur Dioxide (SO2)		0.01	LB/H	0.0006	LB/MMBTU		LIMITS ARE FOR EACH BOILER.
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	OH	05/03/2007 ACT	BOILER (2), NO. 2 FUEL OIL	FUEL OIL #2	20.4	MMBTU/H	Sulfur Dioxide (SO2)		10.4	LB/H	0 51	LB/MMBTU		LIMITS ARE FOR EACH BOILER.
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	OH	05/03/2007 ACT	AIR SUPPLY MAKE UP UNITS (24)	NATURAL GAS	20	MMBTU/H	Sulfur Dioxide (SO2)		0.02	LB/H	0.0006	LB/MMBTU		LIMITS ARE FOR EACH UNIT. 24 AIR SUPPLY MAKE UP UNITS.
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	OH	05/03/2007 ACT	AIR SUPPLY MAKE UP UNITS	NATURAL GAS	28 95	MMBTU/H	Sulfur Dioxide (SO2)		0.02	LB/H	0.0006	LB/MMBTU		
OH-0309	TOLEDO SUPPLIER PARK- PAINT SHOP	OH	05/03/2007 ACT	AIR SUPPLY MAKE UP UNITS (6)	NATURAL GAS	14	MMBTU/H	Sulfur Dioxide (SO2)		0.01	LB/H	0.0006	LB/MMBTU		LIMITS ARE FOR EACH UNIT. 6 AIR SUPPLY UNITS.
OH-0348	LORAINE COUNTY LFG POWER STATION	OH	09/14/2011 ACT	Reciprocating Internal Combustion Engines (10)	Landfill Gas	2233	HP	Sulfur Dioxide (SO2)		0.28	LB/H	0			
OH-0348	LORAINE COUNTY LFG POWER STATION	OH	09/14/2011 ACT	Thermal Oxidizer	landfill gas	6	MMBTU/H	Sulfur Dioxide (SO2)		0.09	LB/H	0			
TX-0371	CORPUS CHRISTI ENERGY CENTER	TX	02/04/2000 EST	(3) TURBINE/HRSG NOS 1-3, CU1-3	NAT GAS			Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMIT	48.35	LB/H	0			
TX-0371	CORPUS CHRISTI ENERGY CENTER	TX	02/04/2000 EST	(3) AUXILIARY BOILERS 1-3, AB1-3	NAT GAS	315	MMBTU/H	Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS.	9.4	LB/H	0 03	LB/MMBTU	EACH, CALCULATED	SO2 STANDARD EMISSIONS REQUIRED IN LB/MMBTU, CALCULATED FROM MAXIMUM ALLOWABLE RATES IN LB/H AND HEAT INPUT CAPACITY.
TX-0371	CORPUS CHRISTI ENERGY CENTER	TX	02/04/2000 EST	ANNUAL TOTALS FOR TURBINES & AUXILIARY BOILERS	GASEOUS FUEL			Sulfur Dioxide (SO2)	FUEL SULFUR CONTENT LIMITS.	189.3	T/YR	0			
TX-0440	CORPUS CHRISTI LNG	TX	01/20/2004 ACT	SUBMERGED COMBUSTION VAPORIZERS (SVCS) -16	NATURAL GAS			Sulfur Dioxide (SO2)	FIRING LOW SULFUR NATURAL GAS IN THE SCVS REPRESENTS BACT FOR SO2 AND PM10.	0.03	LB/H	0			
TX-0440	CORPUS CHRISTI LNG	TX	01/20/2004 ACT	DIESEL FIRWATER PUMP	DIESEL	660	HP	Sulfur Dioxide (SO2)		1.08	LB/H	0			

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TX-0440	CORPUS CHRISTI LNG	TX	01/20/2004 ACT	DIESEL FIREWATER BOOSTER PUMP	DIESEL	525	HP	Sulfur Dioxide (SO2)		1.35	LB/H	0			
TX-0440	CORPUS CHRISTI LNG	TX	01/20/2004 ACT	EMERGENCY DIESEL GENERATOR	DIESEL	1500	KW	Sulfur Dioxide (SO2)		4.44	LB/H	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	SR- 3/4 INCINERATOR				Sulfur Dioxide (SO2)		300	PPMV	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	EAST PROPERTY FLARE				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	COKER FLARE				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	TWENTY ONE FURNACES	REFINERY FUEL GAS			Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	FOURTEEN HEATERS				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	DHT H2 HEATER	HYDROGEN			Sulfur Dioxide (SO2)		300	PPMV	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	CO BOILER	CARBON MONOXIDE			Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	CCU FLARE				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	FOUR TAIL GAS INCINERATORS				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	WEST PROPERTY FLARE				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	THREE FLARES				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0442	SHELL OIL DEER PARK	TX	07/30/2004 ACT	ANALYZER				Sulfur Dioxide (SO2)		300	PPM	0			
TX-0451	DIAMOND SHAMROCK REFINING VALERO	TX	05/20/2004 ACT	COMBUSTION UNITS, TANKS, PROCESS VENTS, LOADING, FLARES, FUGITIVES (4), WASTEWATER, COOLING TOWERS				Sulfur Dioxide (SO2)		466.38	LB/H	0			
TX-0455	DEGUSSA ENGINEERED CARBONS ORANGE CARBON BLACK PLANT	TX	08/21/2003 ACT	WASTE GAS COMBUSTION ANNUAL EMISSIONS CAP				Sulfur Dioxide (SO2)	EMISSIONS OF SO2 WILL BE LIMITED BY REDUCING THE CARBON BLACK OIL FEEDSTOCK SULFUR LEVEL TO 3 0% ON AN ANNUAL BASIS	5821.2	T/YR	0			
TX-0455	DEGUSSA ENGINEERED CARBONS ORANGE CARBON BLACK PLANT	TX	08/21/2003 ACT	VOC INCINERATOR, WASTE HEAT BOILER				Sulfur Dioxide (SO2)	EMISSIONS OF SO2 WILL BE LIMITED BY REDUCING THE CARBON BLACK OIL FEEDSTOCK SULFUR LEVEL TO 3 0% ON AN ANNUAL BASIS	968.8	LB/H	0			
TX-0455	DEGUSSA ENGINEERED CARBONS ORANGE CARBON BLACK PLANT	TX	08/21/2003 ACT	BOILER STACK, DRYER 1-4				Sulfur Dioxide (SO2)	EMISSIONS OF SO2 WILL BE LIMITED BY REDUCING THE CARBON BLACK OIL FEEDSTOCK SULFUR LEVEL TO 3 0% ON AN ANNUAL BASIS	123.3	LB/H	0			
TX-0455	DEGUSSA ENGINEERED CARBONS ORANGE CARBON BLACK PLANT	TX	08/21/2003 ACT	DRYER FILTER 1-4				Sulfur Dioxide (SO2)	EMISSIONS OF SO2 WILL BE LIMITED BY REDUCING THE CARBON BLACK OIL FEEDSTOCK SULFUR LEVEL TO 3 0% ON AN ANNUAL BASIS	12.3	LB/H	0			
TX-0457	CITY PUBLIC SERVICE LEON CREEK PLANT	TX	06/26/2003 ACT	GE LM6000 COMBUSTION TURBINE (4)	NATURAL GAS			Sulfur Dioxide (SO2)	CONTROLLED BY PROPER COMBUSTION OF NATURAL GAS	1.3	LB/H	0			
TX-0457	CITY PUBLIC SERVICE LEON CREEK PLANT	TX	06/26/2003 ACT	EMERGENCY GENERATOR (5)				Sulfur Dioxide (SO2)		2.8	LB/H	0			
TX-0458	JACK COUNTY POWER PLANT	TX	07/22/2003 ACT	COMBUSTION TURBINE WITH 550 MMBTU/HR DUCT BURNER	NATURAL GAS			Sulfur Dioxide (SO2)	BURN LOW SULFUR NATURAL GAS	14.5	LB/H	0			
TX-0458	JACK COUNTY POWER PLANT	TX	07/22/2003 ACT	AUXILIARY BOILER	NATURAL GAS	36	mmbtu/h	Sulfur Dioxide (SO2)		0.3	LB/H	0			
TX-0458	JACK COUNTY POWER PLANT	TX	07/22/2003 ACT	FIRE WATER PUMP ENGINE				Sulfur Dioxide (SO2)		0.5	LB/H	0			
TX-0458	JACK COUNTY POWER PLANT	TX	07/22/2003 ACT	EMERGENCY GENERATOR (6)				Sulfur Dioxide (SO2)		1.4	LB/H	0			
TX-0470	DEGUSSA ENGINEERED CARBONS ORANGE CARBON BLACK PLANT	TX	08/21/2003 ACT	VOC INCINERATOR, WASTE HEAT BOILER	TAIL GAS			Sulfur Dioxide (SO2)	LIMIT SULFUR CONTENT IN TAIL GAS	968.8	LB/H	0			
TX-0470	DEGUSSA ENGINEERED CARBONS ORANGE CARBON BLACK PLANT	TX	08/21/2003 ACT	DRYER FILTER 1-4				Sulfur Dioxide (SO2)	LIMIT SULFUR IN GAS	12.3	LB/H	0			
TX-0470	DEGUSSA ENGINEERED CARBONS ORANGE CARBON BLACK PLANT	TX	08/21/2003 ACT	BOILER STACK, DRYER 1-4				Sulfur Dioxide (SO2)	LIMIT SULFUR IN GAS	123.3	LB/H	0			
TX-0470	DEGUSSA ENGINEERED CARBONS ORANGE CARBON BLACK PLANT	TX	08/21/2003 ACT	WASTE GAS COMBUSTION ANNUAL EMISSIONS CAP				Sulfur Dioxide (SO2)		5821.2	T/YR	0			

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TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	PYROLYSIS FURNACE (1010B)	FUEL GAS	250	MMBtu/H	Sulfur Dioxide (SO2)		0.41	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	PYROLYSIS FURNACES (1001-1008, 1009 B)	FUEL GAS	250	MMBtu/h	Sulfur Dioxide (SO2)		0.38	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	REBOILER (1 AND 2)	FUEL GAS	250	MMBtu	Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	FLARE				Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	DIESEL EMERGENCY GENERATOR				Sulfur Dioxide (SO2)		2.06	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	PYROLYSIS FURNACE (1054-1056)	FUEL GAS	250	mmbtu/h	Sulfur Dioxide (SO2)		0.38	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	PYROLYSIS FURNACE (1057-1062, 1091)	FUEL GAS	250	MMBTU/h	Sulfur Dioxide (SO2)		0.38	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	PYROLYSIS FURNACE (N1011-1012)		250	MMBTU/H	Sulfur Dioxide (SO2)		0.41	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	FLARE (1067)				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	FLARE (1087)				Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	DIESEL EMERGENCY GENERATOR (N7900LJD)	DIESEL			Sulfur Dioxide (SO2)		1.85	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	REGENERATION HEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	SECOND STAGE FEED HEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0475	FORMOSA POINT COMFORT PLANT	TX	05/09/2005 ACT	FLARE (8003B)				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	DHT STRIPPER REBOILER	REFINERY FUEL GAS			Sulfur Dioxide (SO2)		1.9	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	COKER HEATER		291	MMBUT/H	Sulfur Dioxide (SO2)		6.6	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER		62	MMBTU/H	Sulfur Dioxide (SO2)		1.4	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	ACID GAS FLARE				Sulfur Dioxide (SO2)		0.2	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	NO.3 BOILER	REFINERY FUEL GAS	99	MMBTU/H	Sulfur Dioxide (SO2)		2.2	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	TAIL GAS INCINERATOR		100	MMBTU/H	Sulfur Dioxide (SO2)		22.4	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	MIXED DISTILLATE HYDROHEATER REBOILER HEATER	REFINERY FUEL GAS	82	MMBTU/H	Sulfur Dioxide (SO2)		5.7	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	SOUR WATER STRIPPER FLARE				Sulfur Dioxide (SO2)		0.19	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	FLARE-COKE DRUM BLOWDOWN				Sulfur Dioxide (SO2)		1056	LB/H	0			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	TX	04/20/2005 ACT	DHT CHARGER HEATER				Sulfur Dioxide (SO2)		2.1	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	L-AREA GAS TURBINE	NATURAL GAS			Sulfur Dioxide (SO2)		0.03	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N5/6 FLARE				Sulfur Dioxide (SO2)		0.11	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N-3 BACKUP INSTRUMENT AIR COMPRESSOR				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N7/8 PREHEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N3/7 FEED AND EXIT GAS FLARE				Sulfur Dioxide (SO2)		0.11	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N-3,4 PREHEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0487	ROHM AND HAAS CHEMICALS LLC LONE STAR PLANT	TX	03/24/2005 ACT	N-5/6 PREHEATER				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0494	FLINT HILLS RESOURCES INSTALLATION OF BOILERS	TX	01/24/2005 ACT	FLARES 5,6				Sulfur Dioxide (SO2)		942.51	LB/H	0			
TX-0494	FLINT HILLS RESOURCES INSTALLATION OF BOILERS	TX	01/24/2005 ACT	MARINE VAPOR COMBUSTOR				Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0499	SANDY CREEK ENERGY STATION	TX	07/24/2006 ACT	PULVERIZED CAOL BOILER	COAL	8185	MMBTU/H	Sulfur Dioxide (SO2)		2456	LB/H	0			

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TX-0499	SANDY CREEK ENERGY STATION	TX	07/24/2006 ACT	AUXILLARY BOILER	NATURAL GAS	175	MMBTU/H	Sulfur Dioxide (SO2)		0.11	LB/H	0			
TX-0499	SANDY CREEK ENERGY STATION	TX	07/24/2006 ACT	PLANT-EMISSION CAP				Sulfur Dioxide (SO2)		3585	T/YR	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	TURBINE EXHAUST DUCT BURNER (3)	NATURAL GAS			Sulfur Dioxide (SO2)		0.02	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	POWER STEAM BOILER	NATURAL GAS	93	MMBTU/H	Sulfur Dioxide (SO2)		0.05	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	TREATED GAS COMPRESSOR ENGINE STACK WITH CATALYTIC CONVERTER WAUKESHA L-7042GSI		875	HP	Sulfur Dioxide (SO2)		0.46	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	TAIL GAS INCINERATOR STACK				Sulfur Dioxide (SO2)		350	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	BOTTOM HEATERS (2)		15	MMBTU/H	Sulfur Dioxide (SO2)		0.01	LB/H	0			
TX-0501	TEXSTAR GAS PROCESS FACILITY	TX	07/11/2006 ACT	ALLISON 501KB GAS TURBINE GENERATOR	NATURAL GAS			Sulfur Dioxide (SO2)		0.67	LB/H	0			
VA-0297	CITY OF HARRISONBURG RESOURCE RECOVERY FACILITY	VA	11/18/2005 ACT	RESOURCE RECOVERY - WASTE COMBUSTION	SOLID WASTE	34675	tons/year	Sulfur Dioxide (SO2)	DRY-DRY FLUE GAS SCRUBBING SYSTEM USING A HYDRATED LIME SORBENT OR OTHER DEQ APPROVED SUITABLE SORBENT. CEM SYSTEM.	30	PPM @ 7% O2	30	PPM @ 7% O2		
VA-0297	CITY OF HARRISONBURG RESOURCE RECOVERY FACILITY	VA	11/18/2005 ACT	RESOURCE RECOVERY - WASTE COMBUSTION	NATURAL GAS	43.2	mmbtu	Sulfur Dioxide (SO2)	GOOD COMBUSTION PRACTICES AND CEM SYSTEM.	2.19	LB/H	2 03	LB/MMBTU	CALCULATED	
VA-0297	CITY OF HARRISONBURG RESOURCE RECOVERY FACILITY	VA	11/18/2005 ACT	RESOURCE RECOVERY - WASTE COMBUSTION	DISTILLATE OIL	1 08	MMBTU/H	Sulfur Dioxide (SO2)	PROPER OPERATION AND MAINTENANCE.	0.32	LB/H	0.3	LB/MMBTU		

APPENDIX B
COST CALCULATION DETAILS

CONTENTS

Table B1b. Direct and Indirect Installation Costs, Boiler House #1 - Dispersion

Cost Item	**Factor**	**Cost**
Direct Costs		
Purchased Equipment Costs		
Primary Equipment[1]		$ 2,346,681
Ancilliary Equipment		$ -
Allowance for Unforseen		$ 234,668
Instrumentation	0.04	$ 103,254
Sales Taxes	0.06	$ 154,881
Freight	0.05	$ 129,067
Purchased Equipment Cost, PEC		$ 2,968,551
Direct Installation Costs		
Foundations and Supports[2]	0.1	$ 258,135
Handling and Erection	0.75	$ 1,929,124
Electrical	0.01	$ 25,813
Piping	0.04	$ 90,347
Ductwork	0.26	$ 671,151
Painting	0.01	$ 13,165
Direct Installation Costs, DC		$ 2,987,735
Site Preparation		$ 20,000
Buildings		$ -
Total Direct Costs (PEC +DC)		$ 5,976,287
Indirect Costs (Installation)		
Engineering	0.15	$ 445,283
Construction an Field Expenses	0.1	$ 296,855
Contractor Fees	0.1	$ 296,855
Startup	0.006	$ 17,811
Performance Test	0.005	$ 14,843
Model Study	0	$ -
Contingencies	0.1	$ 296,855
Total Indirect Costs, IC		$ 1,368,502
Total Installed Cost		**$ 7,324,789**

[1] Primary equipment includes stack/chimney. Ancillary equipment includes:
partial quench system, and ID fans.

2 Due to the high water table at this location, it is probable that piling foundations will be required for instllation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required.

Table B1a. Annual Cost Factors, Boiler House #1 - Dispersion

Cost Item	Factor	Cost
Direct Annual Costs, DC		
Operating Labor		
Operator	General Operating	$ 28,470
Supervisor	15% of Operator	$ 4,271
Material	5% of total operating	$ 1,637
Maintenance		
Maintenance Employee	General Maintenance	$ 63,489
Supervisor	15% of Maintenance Labor	$ 11,204
Material	100% of Maintenance Labor	$ 74,693
Utilities		
Electricity		$ 137,163
Water		$ 21,024
Indirect Annual Costs, IC		
Administrative Charges	2% of Total Capital Investment	$ 146,496
Property Tax	1% of Total Capital Investment	$ 73,248
Insurance	1% of Total Capital Investment	$ 73,248
Overhead	60% of total Labor and Materials	$ 204,189
Capital Recovery	0.1098 x Total Capital Investment	$ 804,262
Total Annual Cost		**$ 1,643,394**
	2010 Uncontrolled SO_2 Actual Emissions (tpy)	*407.35*
	Ambient Air Quality Impact Reduction (ug/m^3)	*13.8*
	Control Cost Per ug/m^3 Reduction in SO_2 Impact	***$ 119,259***

[1] Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #1 Dispersion

Notes

KJ 2-12-14

1 This option involves ducting the flue gas from all five boilers in the boilerhouse into one common duct. This duct will convey the flue gas approximately 450 feet to and ID fan and GEP stack/chimney.

4 Installed Equipment Costs for Boiler House #1 - Dispersion

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	New Chimney/stack	1	-	-	International Chimney Corp.	1	$ 666,667	$666,667	2014	1	1	1	$ 666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	$ 104,576	$104,576	2014	1	1	1	$ 104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	$ 472,844	$472,844	2014	1	1	1	$ 472,844
4	New Fans	4	CS	CS	Included with baghouse	1	$ 554,774	$554,774	2014	1	1	1	$ 554,774
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	$ 658	$361,900	2011	593	600	1	$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	$ 109,852	$109,852	2011	593	600	1	$ 111,148
7	Partial Quench System	9	CS	CS	CB&I Estimate	1	$ 70,500	$70,500	2014	1	1	1	$ 70,500
8													
9													
10													
21													
													$ 2,346,681

Notes:

1 New stack cost based on estimate from International Chimney Corporation, ICC File CC-42408-C, February 27, 2014.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECOST3, EPA cost model, 2014 basis. Estimate based on duct flow of 330,130 acfm acfm at 300 Deg. F.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Partial quench system @ 200 gpm (pumps, valves, lances/nozzles, duct corrosion lining).

5.0 Installed Equipment Costs for Boiler House #1 Dispersion

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity

Fan Electricity

Flow	330130	ACFM	
Pressure Drop	5	iwc	(4 inches duct, 1 inch stack)
Fan Efficiency	0.8	fraction	
Gas S.G. (Air = 1)	1		Use 1
Belt Efficiency	1		Typical Efficiencies
Motor Efficiency	0.95		Motor *1kW - 0.4*
Power (BHP)	325	BHP	Motor *10 kW - 0.87*
Motor Efficiency	95	%	
Power (KW)	254.8	KW	Motor *100 kW - 0.92*
Electricity Cost ($/KW-hr)	$ 0.06		Belt *1 kW - 0.78*
Hours Operated/Yr	8760	hr	Belt *10 kW - 0.88*
Annual Electricity Cost ($)	$ 133,930		Belt *100 kW - 0.93*

Pumping

Pumping Rate	200	gpm
TDH	200	ft
Pump Efficiency	75%	
Motor Efficiency	92%	
Annual Hours of Operation	8760	hr/yr
Electricity Cost ($/KW-hr)	0.06	$/Kw-hr
Brake Horsepower	7.59	BHP
Annual Electricity Cost	$ 3,233.48	($/year)

Electricity Other Uses

Other Costs	0	KW
Electricity Cost ($/KW-hr)	$ 0.06	
Hours Operated/Yr	8760	hr
Annual Electricity Cost ($)	$ -	
Total Electricity Cost ($)	**$ 137,163.18**	

2.0 Water Costs

Partial Quench

Estimated Partial Quench (gpm)	200	Quench associated with lowering temperature of flue gas
Hours Per Year	8760	
Water Cost ($/kgal)	$ 0.20	
Annual Water Cost	**$ 21,024**	

3.0 Operating Labor Cost

Quench System	$ 18,980.00	26 $/hr	730	1 hr/shift x 2 shifts x 365 day/yr
Stack	$ 9,490.00	26 $/hr	365	1 hr/day x 365 day/yr
Misc.	$ -			
Supervision	$ 4,270.50	Note 1		
Annual Total Operating Labor	**$ 32,740.50**			

4.0 Maintenance

Total Installed Direct Cost	$ 2,987,735	
Total Maintenance Materials	$ 74,693	Note 2
Total Maintenance Labor	$ 74,693	Note 2
Total Annual Maintenance Cost	**$ 149,387**	Note 3

TOTAL LABOR AND MATERIALS	**$ 340,314.44**

5.0 Installed Equipment Costs for Boiler House #1 Dispersion

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on CEUCOST basis of 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.

Table B2b. Direct and Indirect Installation Costs, Boiler House #2 - Dispersion

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment[1]		$ 2,504,827
Ancilliary Equipment		$ -
Allowance for Unforseen		$ 250,483
Instrumentation	0.04	$ 110,212.39
Sales Taxes	0.06	$ 165,318.58
Freight	0.05	$ 137,765.49
Purchased Equipment Cost, PEC		$ 3,168,606
Direct Installation Costs		
Foundations and Supports[2]	0.1	$ 275,531
Handling and Erection	0.69	$ 1,903,834
Electrical	0.01	$ 27,553
Piping	0.03	$ 95,058
Ductwork	0.25	$ 688,827
Painting	0.01	$ 14,052
Direct Installation Costs, DC		$ 3,004,856
Site Preparation		$ 20,000
Buildings		$ -
Total Direct Costs (PEC +DC)		$ 6,193,462
Indirect Costs (Installation)		
Engineering	0.15	$ 475,291
Construction an Field Expenses	0.1	$ 316,861
Contractor Fees	0.1	$ 316,861
Startup	0.006	$ 19,012
Performance Test	0.005	$ 15,843
Model Study	0	$ -
Contingencies	0.1	$ 316,861
Total Indirect Costs, IC		$ 1,460,727
Total Installed Cost		**$ 7,654,189**

1 Primary equipment includes stack/chimney. Ancillary equipment includes: partial quench system, and ID fans.

2 Due to the high water table at this location, it is probable that piling foundations will be required for instllation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required.

Table B2a. Annual Cost Factors, Boiler House #2 - Dispersion

Cost Item	Factor	Cost	
Direct Annual Costs, DC			
Operating Labor			
Operator	General Operating	$	28,470
Supervisor	15% of Operator	$	4,271
Material	5% of total operating	$	1,637
Maintenance			
Maintenance Employee	General Maintenance	$	63,853
Supervisor	15% of Maintenance Labor	$	11,268
Material	100% of Maintenance Labor	$	75,121
Utilities			
Electricity		$	168,612
Water		$	21,024
Indirect Annual Costs, IC			
Administrative Charges	2% of Total Capital Investment	$	153,084
Property Tax	1% of Total Capital Investment	$	76,542
Insurance	1% of Total Capital Investment	$	76,542
Overhead	60% of total Labor and Materials	$	223,572
Capital Recovery[1]	0.1098 x Total Capital Investment	$	840,430
Total Annual Cost		**$**	**1,744,426**
	2010 Uncontrolled SO_2 Actual Emissions (tpy)		*750.35*
	Ambient Air Quality Impact Reduction (ug/m^3)		*8.3*
	Control Cost Per ug/m^3 Reduction in SO_2 Impact	***$***	***210,934***

[1] Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #2 Dispersion

Notes

KJ 2-12-14

1 This option involves ducting the flue gas from all five boilers in the boilerhouse into one common duct. This duct will convey the flue gas approximately 450 feet to and ID fan and GEP stack/chimney.

4 Installed Equipment Costs for Boiler House #2 Dispersion

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	New Chimney/stack	1	-	-	International Chimney Corp.	1	$ 666,667	$666,667	2014	1	1	1	$ 666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	$ 104,576	$104,576	2014	1	1	1	$ 104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	$ 472,844	$472,844	2014	1	1	1	$ 472,844
4	New Fans (2)	4	CS	CS	CUECOST3	1	$ 712,920	$712,920	2014	1	1	1	$ 712,920
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	$ 658	$361,900	2011	593	600	1	$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	$ 109,852	$109,852	2011	593	600	1	$ 111,148
7	Partial Quench System	9	CS	CS	CB&I Estimate	1	$ 70,500	$70,500	2014	1	1	1	$ 70,500
8													
9													
10													
21													
													$ 2,504,827

Notes:

1 Estimate for self supporting stack, 12'10" diameter, including aircarft warning lights, ladder, and testing platform. Pricing from International Chimney Corporation, ICC File CC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CEUCOST3, EPA cost model, 1998 basis. Estimate based on duct flow of 330,130 acfm acfm at 300 Deg. F.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Partial quench system @ 200 gpm (pumps, valves, lances/nozzles, duct corrosion lining).

5.0 Installed Equipment Costs for Boiler House #2 Dispersion

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity

Fan Electricity

Flow	406355	ACFM	
Pressure Drop	5	iwc	(4 inches duct, 1 inch stack)
Fan Efficiency	0.8	fraction	
Gas S.G. (Air = 1)	1		Use 1
Belt Efficiency	1		Typical Efficiencies
Motor Efficiency	0.95		Motor *1kW - 0.4*
Power (BHP)	400	BHP	Motor *10 kW - 0.87*
Motor Efficiency	95	%	
Power (KW)	313.6	KW	Motor *100 kW - 0.92*
Electricity Cost ($/KW-hr)	$ 0.06		Belt *1 kW - 0.78*
Hours Operated/Yr	8760	hr	Belt *10 kW - 0.88*
Annual Electricity Cost ($)	$ 164,853		Belt *100 kW - 0.93*

Pumping

Pumping Rate	200	gpm
TDH	200	ft
Pump Efficiency	75%	
Motor Efficiency	92%	
Annual Hours of Operation	8760	hr/yr
Electricity Cost ($/KW-hr)	0.06	$/Kw-hr
Brake Horsepower	7.59	BHP
Annual Electricity Cost	$ 3,233.48	($/year)

	acfm	Deg. F
Base Boiler Flow	540025	550
Quenched	406355	300

Electricity Other Uses

From CEUCOST3	1	KW
Electricity Cost ($/KW-hr)	$ 0.06	
Hours Operated/Yr	8760	hr
Annual Electricity Cost ($)	$ 525.60	

Total Electricity Cost ($)	**$ 168,612**

2.0 Water Costs

Partial Quench

Estimated Partial Quench (gpm)	200	Quench associated with lowering temperature of flue gas
Hours Per Year	8760	
Water Cost ($/kgal)	$ 0.20	
Annual Water Cost	**$ 21,024**	

3.0 Operating Labor Cost

Quench System	$ 18,980.00	26	$/hr	730	1 hr/shift x 2 shifts x 365 day/yr
Stack	$ 9,490.00	26	$/hr	365	1 hr/day x 365 day/yr
Misc.	$ -				
Supervision	$ 4,270.50	Note 1			
Annual Total Operating Labor	**$ 32,740.50**				

4.0 Maintenance

Total Installed Direct Cost	$ 3,004,856	
Total Maintenance Materials	$ 75,121	Note 2
Total Maintenance Labor	$ 75,121	Note 2
Total Annual Maintenance Cost	**$ 150,243**	Note 3

TOTAL LABOR AND MATERIALS	**$ 372,619.61**

5.0 Installed Equipment Costs for Boiler House #2 Dispersion

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

Notes:
1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on CEUCOST basis of 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.

Table B3b. Direct and Indirect Installation Costs, HSM Furnaces - Dispersion

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment[1]		$ 3,606,756
Ancilliary Equipment		$ -
Allowance for Unforseen		$ 360,676
Instrumentation	0.04	$ 158,697
Sales Taxes	0.06	$ 238,046
Freight	0.05	$ 198,372
Purchased Equipment Cost, PEC		$ 4,562,546
Direct Installation Costs		
Foundations and Supports[2]	0.125	$ 495,929
Handling and Erection	0.50	$ 1,977,749
Electrical	0.01	$ 39,674
Piping	0.03	$ 99,186
Ductwork	0.34	$ 1,344,959
Painting	0.01	$ 20,234
Direct Installation Costs, DC		$ 3,977,731
Site Preparation		$ 20,000
Buildings		$ -
Total Direct Costs (PEC +DC)		$ 8,560,277
Indirect Costs (Installation)		
Engineering	0.15	$ 684,382
Construction an Field Expenses	0.1	$ 456,255
Contractor Fees	0.1	$ 456,255
Startup	0.006	$ 27,375
Performance Test	0.005	$ 22,813
Model Study	0	$ -
Contingencies	0.1	$ 456,255
Total Indirect Costs, IC		$ 2,103,334
Total Installed Cost		**$ 10,663,611**

1 Primary equipment includes stack/chimney. Ancillary equipment includes: partial quench system, and ID fans.

2 Due to the high water table at this location, it is probable that piling foundations will be required for instllation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required.

Table B3a. Annual Cost Factors, HSM Furnaces - Dispersion

Cost Item	Factor	Cost	
Direct Annual Costs, DC			
Operating Labor			
Operator	General Operating	$	37,960
Supervisor	15% of Operator	$	5,694
Material	5% of total operating	$	2,183
Maintenance			
Maintenance Employee	General Maintenance	$	84,527
Supervisor	15% of Maintenance Labor	$	14,916
Material	100% of Maintenance Labor	$	99,443
Utilities			
Electricity		$	293,997
Water		$	42,048
Indirect Annual Costs, IC			
Administrative Charges	2% of Total Capital Investment	$	213,272
Property Tax	1% of Total Capital Investment	$	106,636
Insurance	1% of Total Capital Investment	$	106,636
Overhead	60% of total Labor and Materials	$	347,151
Capital Recovery[1]	0.1098 x Total Capital Investment	$	1,170,864
Total Annual Cost		**$**	**2,525,328**
	2010 Uncontrolled SO_2 Actual Emissions (tpy)		*2240.06*
	Ambient Air Quality Impact Reduction (ug/m^3)		*30.5*
	Control Cost Per ug/m^3 Reduction in SO_2 Impact	***$***	***82,934***

[1] Capital Recovery Actor is derived rom EPA Air Pollution control Cost Manual, Xixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for HSM Furnaces Dispersion

Notes

KJ 2-12-14

1 This option involves ducting the flue gas from all five boilers in the boilerhouse into one common duct. This duct will convey the flue gas approximately 450 feet to and ID fan and GEP stack/chimney.

4 Installed Equipment Costs for HSM Furnaces Dispersion

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	New Chimney/stack	1	-	-	International Chimney Corp.	1	$ 833,333	$833,333	2014	1	1	1	$ 833,333
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	2	$ 104,576	$209,152	2014	1	1	1	$ 209,152
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	2	$ 472,844	$945,688	2014	1	1	1	$ 945,688
4	New Fans	4	CS	CS	Fans (2)	1	$ 1,000,262	$1,000,262	2014	1	1	1	$ 1,000,262
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	$ 658	$361,900	2011	593	600	1	$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	$ 109,852	$109,852	2011	593	600	1	$ 111,148
7	Partial Quench System	9	CS	CS	CB&I Estimate	1	$ 141,000	$141,000	2014	1	1	1	$ 141,000
8													
9													
10													
21													
													$ 3,606,756

Notes:

1. Estimate for self supporting column (concrete with block lining), 16' 10" diameter, including aircraft lights, ladder and testing platforms. Pricing from International Chimney Corporation, ICC File CC-42408-C.
2. New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.
3. New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet. Two parallel ducts will be required for this case.
4. New fan cost is included in the baghouse estimate calculated from CUECOST3, EPA cost model, 2014 basis.
5. Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.
6. Typical allowance, as specified in RLMeans for ancillary piping/duct materials.
7. Partial quench system @ 400 gpm (pumps, valves, lances/nozzles, duct corrosion lining).

5.0 Installed Equipment Costs for HSM Furnaces Dispersion

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity

Fan Electricity

Flow	702269	ACFM	
Pressure Drop	5	iwc	(4 inches duct, 1 inch stack)
Fan Efficiency	0.8	fraction	
Gas S.G. (Air = 1)	1		Use 1
Belt Efficiency	1		Typical Efficiencies
Motor Efficiency	0.95		Motor *1kW - 0.4*
Power (BHP)	691	BHP	Motor *10 kW - 0.87*
Motor Efficiency	95	%	
Power (KW)	542.1	KW	Motor *100 kW - 0.92*
Electricity Cost ($/KW-hr)	$ 0.06		Belt *1 kW - 0.78*
Hours Operated/Yr	8760	hr	Belt *10 kW - 0.88*
Annual Electricity Cost ($)	$ 284,902		Belt *100 kW - 0.93*

Pumping

Pumping Rate	400	gpm
TDH	200	ft
Pump Efficiency	75%	
Motor Efficiency	92%	
Annual Hours of Operation	8760	hr/yr
Electricity Cost ($/KW-hr)	0.06	$/Kw-hr
Brake Horsepower	15.18	BHP
Annual Electricity Cost	$ 6,466.96	($/year)

	acfm	Temp (Deg. F)	
Base Boiler Flow	933279	550	
Quenched	702269	300	
Fan Outlet	706890	305	5 Deg F reheat

Electricity Other Uses

From CEUCOST3	5	KW
Electricity Cost ($/KW-hr)	$ 0.06	
Hours Operated/Yr	8760	hr
Annual Electricity Cost ($)	$ 2,628.00	

Total Electricity Cost ($)	**$ 293,997**

2.0 Water Costs

Partial Quench

Estimated Partial Quench (gpm)	400	Quench associated with lowering temperature of flue gas
Hours Per Year	8760	
Water Cost ($/kgal)	$ 0.20	
Annual Water Cost	**$ 42,048**	

3.0 Operating Labor Cost

Quench System	$ 18,980.00	26 $/hr	730	1 hr/shift x 2 shifts x 365 day/yr
Stack	$ 18,980.00	26 $/hr	730	1 hr/day x 365 day/yr
Misc.	$ -			
Supervision	$ 5,694.00	Note 1		
Annual Total Operating Labor	**$ 43,654.00**			

4.0 Maintenance

Total Installed Direct Cost	$ 3,977,731	
Total Maintenance Materials	$ 99,443	Note 2
Total Maintenance Labor	$ 99,443	Note 2
Total Annual Maintenance Cost	**$ 198,887**	Note 3

TOTAL LABOR AND MATERIALS	**$ 578,585**

5.0 Installed Equipment Costs for HSM Furnaces Dispersion

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on CEUCOST basis of 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.

Table B4b. Direct and Indirect Installation Costs, Boiler House #1 - Fuel Switching

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment[1]		$ 6,030,927
Ancilliary Equipment		$ -
Allowance for Unforseen		$ 603,093
Instrumentation	0.04	$ 265,361
Sales Taxes	0.06	$ 398,041
Freight	0.05	$ 331,701
Purchased Equipment Cost, PEC		$ 7,629,123
Direct Installation Costs		
Foundations and Supports	0.05	$ 331,701
Handling and Erection	0.69	$ 4,554,641
Electrical	0.05	$ 331,701
Piping	0.08	$ 530,722
Ductwork	0.02	$ 119,412
Painting	0.01	$ 33,834
Direct Installation Costs, DC		$ 5,902,010
Site Preparation		$ 20,000
Buildings		$ -
Total Direct Costs (PEC +DC)		$ 13,551,133
Indirect Costs (Installation)		
Engineering	0.15	$ 1,144,368
Construction an Field Expenses	0.1	$ 762,912
Contractor Fees	0.1	$ 762,912
Startup	0.006	$ 45,775
Performance Test	0.007	$ 53,404
Model Study	0	$ -
Contingencies	0.1	$ 762,912
Two-Week Lost Production at the Blast Furnace		$ 8,031,000
Total Indirect Costs, IC		$ 11,563,284
Total Installed Cost		**$ 25,114,417**

[1] Primary equipment includes : replacement low NOx burner systems. Also included is replacement natural gas fuel supply system.

Table B4a. Annual Cost Factors, Boiler House #1 - Fuel Switching

Cost Item			Factor	Cost	
Direct Annual Costs, DC					
	Operating Labor				
		Operator	General Operating	$	18,980
		Supervisor	15% of Operator	$	2,847
		Material	5% of Total Operating	$	1,091
	Maintenance				
		Maintenance Employee	General Maintenance	$	125,418
		Supervisor	15% of Maintenance Labor	$	22,133
		Material	100% of Maintenance Labor	$	147,550
	Utilities				
		Annual Fuel Switching Costs		$	1,146,110
Indirect Annual Costs, IC					
	Administrative Charges		2% of Total Capital Investment	$	502,288
	Property Tax		1% of Total Capital Investment	$	251,144
	Insurance		1% of Total Capital Investment	$	251,144
	Overhead		60% of total Labor and Materials	$	876,115
	Capital Recovery[1]		0.1098 x Total Capital Investment	$	2,757,563
Total Annual Cost				$	6,102,383
			2010 Uncontrolled SO_2 Actual Emissions (tpy)		*407.35*
			Allowance for Uncontrolled Maint. Outages (tpy) - 15 days		*0.0*
			SO_2 Removal Efficiency		*88.62%*
			Post-Control Emission Factor (lb/MMBtu)		*0.055*
			Control Cost Per Ton SO_2	***$***	***16,904***

[1] Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #1 Fuel Switching

Notes

KJ 2-12-14

1. This option involves replacment of existing burners in the boiler house. There are five boilers, each equipped with 4 natural gas burners. To burn 100% natural gas, these will need to be replaced with new low Nox burners. The natural gas burner upgrade will also necessitate the replacement of the natural gas supply piping to the burners to provide sufficient natural gas. This estimate is based on the natural gas utility providing gas supply to the property line, and USS installation of in-plant distribution piping.

4 Installed Equipment Costs for Boiler House #1 Fuel Switching

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	Burner System	1	CS	CS	North American Combustion , Inc.	20	$ 235,000	$4,700,000	2014	1	1	1	$ 4,700,000
2	Fuel Delivery System Replacement	2	CS	CS	CB&I Estimate	1	$ 1,330,927	$1,330,927	2014	1	1	1	$ 1,330,927
3													
4													
5													
6													
7													
8													
9													
10													
21													
													$ 6,030,927

Notes:

1 Burner system includes burner, fuel train/control valves, two (2) blowers, and control panel (I&C).

2 Fuel delivery replacement sized based on 1,000 MMBtu/hr capacity, assumes that utility will bring NG to site. Tie point will be Zug Island Rd on north side. Fuel piping will be routed along existing structural support systsems. Pricing based on Sch. 40 CS.

5.0 Installed Equipment Costs for Boiler House #1 Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

5.1 Baseline Cost of Fuel

Total Rating	1,684,852	MMBtu/yr				Baseline SO_2 Emissions			
Baseline NG	69,206	MMBtu/yr		Btu/scf	NG	0.0006	41	lb/yr
Baseline COG	503,315	MMBtu/yr	NG HHV	1012	COG	1.431	720,385	lb/yr
Baseline BFG	1,112,332	MMBtu/yr	BFG HHV	89	BFG	0.08279	92,087	lb/yr
Annual Hours Operation	8,760	hrs/yr	COG HHV	496		Total	812,513	lb/yr
Cost NG ($ per MMBtu)	$ 4.89	(Based on 2010 cost)					406	tpy
Cost COG ($ per MMBtu)	$ 2.92	(Based on 2010 Cost)						
Baseline Annual Cost	$ 1,808,096	(Cost NG and COG)						

5.2 Fuel Use After Fuel Switch

Total Rating	1,684,852	MMBtu/yr		Btu/scf		Post-Fuel Switch SO_2 Emissions		
Post-Fuel Switch NG	572,521	MMBtu/yr	NG HHV	1012	NG	0.0006	339	lb/yr
Post-Fuel Switch COG	-	MMBtu/yr	BFG HHV	89	COG	1.431	-	lb/yr
Post-Fuel Switch BFG	1,112,332	MMBtu/yr	COG HHV	496	BFG	0.082787	92,087	lb/yr
Annual Hours Operation	8,760	hrs/yr				Total	92,426	lb/yr
Cost NG ($ per MMBtu)	$ 5.16	(Based on average EIA Short-Term Projection for 2014/2015)					46	tpy
Future Projected Annual Cost	$ 2,954,207	(Cost NG and COG)						
				Post-Fuel Switch SO_2 Emission Reduction			360.0	tpy
					Post Control SO_2 Factor:		0.0549	lb/MMBtu

5.3 Baseline Fuel Cost - Fuel Swich Fuel Cost

$ 1,146,110

3.0 Operating Labor Cost

Burners	$ 18,980	26 $/hr	730	1 hr/shift x 2 shifts x 365 day/yr
Other	$ -	26 $/hr	0	-
Annual Total Operating Labor	**$ 18,980**			

4.0 Maintenance

Total Installed Direct Cost	$ 5,902,010	
Total Maintenance Materials	$ 147,550	Note 2
Total Maintenance Labor	$ 147,550	Note 2
Total Annual Maintenance Cost	**$ 295,101**	Note 3
TOTAL LABOR AND MATERIALS	**$ 1,460,191**	

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
4. Fuel SO_2 emission factors from 2013 Air Inventory.

5.0 Installed Equipment Costs for Boiler House #1 Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

Flow			Flow
	5%	NG	
	28%	COG	
	67%	BFG	
	100%		

Table B5b. Direct and Indirect Installation Costs, Boiler House #2 - Fuel Switching

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment[1]		$ 6,090,046
Ancilliary Equipment		$ -
Allowance for Unforseen		$ 609,005
Instrumentation	0.04	$ 267,962.04
Sales Taxes	0.06	$ 401,943
Freight	0.05	$ 334,953
Purchased Equipment Cost, PEC		$ 7,703,909
Direct Installation Costs		
Foundations and Supports	0.05	$ 334,953
Handling and Erection	0.68	$ 4,560,550
Electrical	0.05	$ 334,953
Piping	0.08	$ 535,924
Ductwork	0.02	$ 133,981
Painting	0.01	$ 34,165
Direct Installation Costs, DC		$ 5,934,526
Site Preparation		$ 20,000
Buildings		$ -
Total Direct Costs (PEC +DC)		$ 13,658,434
Indirect Costs (Installation)		
Engineering	0.15	$ 1,155,586
Construction an Field Expenses	0.1	$ 770,391
Contractor Fees	0.1	$ 770,391
Startup	0.006	$ 46,223
Performance Test	0.02	$ 154,078
Model Study	0	$ -
Contingencies	0.1	$ 770,391
Two-Week Lost Production at the Blast Furnace		$ 8,031,000
Total Indirect Costs, IC		$ 11,698,061
Total Installed Cost		**$ 25,356,495**

[1] Primary equipment includes : replacement low NOx burner systems. Also included is replacement natural gas fuel supply system.

Table B5a. Annual Cost Factors, Boiler House #2 - Fuel Switching

Cost Item	Factor	Cost
Direct Annual Costs, DC		
Operating Labor		
Operator	General Operating	$ 18,980
Supervisor	15% of Operator	$ 2,847
Material	5% of Total Operating	$ 1,091
Maintenance		
Maintenance Employee	General Maintenance	$ 126,109
Supervisor	15% of Maintenance Labor	$ 22,254
Material	100% of Maintenance Labor	$ 148,363
Utilities		
Cost of Fuel Switch (Natural Gas for COG) 2010 Basis		$ 2,075,812
Indirect Annual Costs, IC		
Administrative Charges	2% of Total Capital Investment	$ 507,130
Property Tax	1% of Total Capital Investment	$ 253,565
Insurance	1% of Total Capital Investment	$ 253,565
Overhead	60% of total Labor and Materials	$ 1,434,911
Capital Recovery[1]	0.1098 x Total Capital Investment	$ 2,784,143
Total Annual Cost		$ 7,628,771
	2010 Uncontrolled SO_2 Actual Emissions (tpy)	*750*
	Allowance for Uncontrolled Maint. Outages (tpy) - 15 days	*0.0*
	SO_2 Removal Efficiency	*83.80%*
	Post-Control Emission Factor (lb/MMBtu)	*0.057*
	Control Cost Per Ton SO_2	***$ 12,133***

[1] Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #2 Fuel Switching

Notes

KJ 2-12-14

1 This option involves replacment of existing burners in the boiler house. There are five boilers, each equipped with 4 natural gas burners. To burn 100% natural gas, these will need to be replaced with new low NOx burners. The natural gas burner upgrade will also necessitate the replacement of the natural gas supply piping to the burners to provide sufficient natural gas. This estimate is based on the natural gas utility providing gas supply to the property line, and USS providing installation of in-plant distribution piping.

4 Installed Equipment Costs for Boiler House #2 Fuel Switching

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	Burner System	1	CS	CS	North American Combustion , Inc.	20	$ 235,000	$4,700,000	2014	1	1	1	$ 4,700,000
2	Fuel Delivery System Replacement	2	CS	CS	CB&I Estimate	1	$ 1,390,046	$1,390,046	2014	1	1	1	$ 1,390,046
3													
4													
5													
6													
7													
8													
9													
10													
21													
													$ 6,090,046

Notes:

1 Burner system includes burner, fuel train/control valves, blower, and control panel (I&C).

2 Fuel delivery replacement sized based on 1,000 MMBtu/hr capacity, assumes that utility will bring NG to site. Tie point will be Zug Island Rd on north side.
Fuel piping will be routed along existing structural support systsems. Pricing based on Sch. 40 CS.

5.0 Installed Equipment Costs for Boiler House #2 Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

5.1 Baseline Cost of Fuel -2010

Total Usage	4,216,399	MMBtu/yr		Btu/scf					
Baseline NG	424,030	MMBtu/yr	NG HHV	1012	NG	0.0006	251.40	lbs /yr
Baseline COG	875,590	MMBtu/yr	BFG HHV	89	COG	1.431	1,253,217.00	lbs /yr
Baseline BFG	2,916,778	MMBtu/yr	COG HHV	496	BFG	0.08279	241,472.12	lbs /yr
Annual Hours Operation	8,760	hrs/yr				Total	1,494,941	lbs /yr
Cost NG	$ 4.89	(Based on 2010 cost)					747.47	tons /yr
Cost COG	$ 2.92	(Based on 2010 Cost)						
Baseline Annual Cost	$ 4,630,232	(Cost NG and COG)						

5.2 Fuel Use After Fuel Switch

Total Rating	4,216,399	MMBtu/yr		Btu/scf				
Post Fuel Switch NG	1,299,621	MMBtu/yr	NG HHV	1012	NG	0.0006	770.53	lbs /yr
Post Fuel Switch COG	-	MMBtu/yr	BFG HHV	89	COG	1.431	-	lbs /yr
Post Fuel Switch BFG	2,916,778	MMBtu/yr	COG HHV	496	BFG	0.082787	241,472	lbs /yr
Annual Hours Operation	8,760	hrs/yr				Total	242,243	lbs /yr
Cost NG	$ 5.16	(Based on average EIA Short-Term Projection for 2014/2015)					121.12	tons /yr
Future Projected Annual Cost	$ 6,706,045	(Cost NG and COG)						

Post Fuel Switch SO_2 Emission Reduction 626.35 tpy

Post Control SO_2 Factor: 0 057 lb/MMBtu

5.3 Baseline Fuel Cost - Fuel Swich Fuel Cost

$ 2,075,812

3.0 Operating Labor Cost

Burners	$ 18,980	26 $/hr	730	1 hr/shift x 2 shifts x 365 day/yr
Other	$ -	26 $/hr	0	-
Annual Total Operating Labor	**$ 18,980**			

4.0 Maintenance

Total Installed Direct Cost	$ 5,934,526	
Total Maintenance Materials	$ 148,363	Note 2
Total Maintenance Labor	$ 148,363	Note 2
Total Annual Maintenance Cost	**$ 296,726**	Note 3
TOTAL LABOR AND MATERIALS	**$ 2,391,519**	

Notes:
1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
4. Fuel SO_2 emission factors from 2013 Air Inventory.

Table B6b. Direct and Indirect Installation Costs, HSM Furnaces - Fuel Switching

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment[1]		$ 13,658,240
Ancilliary Equipment		$ -
Allowance for Unforseen		$ 1,365,824
Instrumentation	0.04	$ 600,963
Sales Taxes	0.06	$ 901,444
Freight	0.05	$ 751,203
Purchased Equipment Cost, PEC		$ 17,277,674
Direct Installation Costs		
Foundations and Supports	0.05	$ 751,203
Handling and Erection	0.45	$ 6,801,702
Electrical	0.056	$ 841,348
Piping	0.07	$ 1,051,684
Ductwork	0.03	$ 450,722
Painting	0.01	$ 76,623
Direct Installation Costs, DC		$ 9,973,282
Site Preparation		$ 20,000
Buildings		$ -
Total Direct Costs (PEC +DC)		$ 27,270,956
Indirect Costs (Installation)		
Engineering	0.15	$ 2,591,651
Construction an Field Expenses	0.1	$ 1,727,767
Contractor Fees	0.1	$ 1,727,767
Startup	0.006	$ 103,666
Performance Test	0.02	$ 345,553
Model Study	0	$ -
Contingencies	0.1	$ 1,727,767
Two-Week Lost Production at the HSM		$ 15,600,000
Total Indirect Costs, IC		$ 23,824,173
Total Installed Cost		**$ 51,095,128**

[1] Primary equipment includes : replacement low NOx burner systems. Also included is replacement of fuel line to handle added natural gas demand.

Table B6a. Annual Cost Factors, HSM Furnaces - Fuel Switching

Cost Item	Factor	Cost
Direct Annual Costs, DC		
Operating Labor		
Operator	General Operating	$ 18,980
Supervisor	15% of Operator	$ 2,847
Material	5% of Total Operating	$ 1,091
Maintenance		
Maintenance Employee	General Maintenance	$ 91,953
Supervisor	15% of Maintenance Labor	$ 16,227
Material	100% of Maintenance Labor	$ 108,180
Utilities		
Fuel Switch Replacement Cost		$ 7,765,439
Indirect Annual Costs, IC		
Administrative Charges	2% of Total Capital Investment	$ 1,021,903
Property Tax	1% of Total Capital Investment	$ 510,951
Insurance	1% of Total Capital Investment	$ 510,951
Overhead	60% of total Labor and Materials	$ 4,800,468
Capital Recovery	0.1098 x Total Capital Investment	$ 5,610,245
Total Annual Cost		$ 20,459,236
	2010 Uncontrolled SO_2 Actual Emissions (tpy)	*2240.1*
	Allowance for Uncontrolled Maint. Outages (tpy) - 15 days	*0.0*
	SO_2 Removal Efficiency	*99.92%*
	Post-Control Emission Factor (lb/MMBtu)	*0.0006*
	Control Cost Per Ton SO_2	***$ 9,129***

[1] Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for HSM Fuel Switching

Notes

KJ 2-12-14

1 This option involves replacment of existing COG burners in the boiler house. There are five furnaces, each equipped with multiple natural gas and COG burners. To burn 100% natural gas, these will need to be replaced with new low NOx burners. The natural gas burner upgrade will also necessitate the replacement of the natural gas supply piping to the burners to provide sufficient natural gas. This esimate is based on the natural gas utility providing gas supply to the property line, and USS installation of in-plant distribution piping.

4 Installed Equipment Costs for HSM Fuel Switching

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	COG to NG Replacement Burners 12.5 MM	1	CS	CS	North American Combustion , Inc.	75	$ 65,000	$4,875,000	2014	1	1	1	$ 4,875,000
2	COG to NG Replacement Burners 17.5 MM	2	CS	CS	North American Combustion , Inc.	80	$ 80,000	$6,400,000	2014	1	1	1	$ 6,400,000
3	Panels and Instrumentation	3	-	-	North American Combustion , Inc.	5	$ 100,000	$500,000	2014	1	1	1	$ 500,000
4	Panels and Instrumentation	4	-	-	North American Combustion , Inc.	5	$ 100,000	$500,000	2014	1	1	1	$ 500,000
5	Fuel Delivery System Replacement	2	CS	CS	CB&I Estimate	1	$ 1,383,240	$1,383,240	2014	1	1	1	$ 1,383,240
6													
7													
8													
9													
10													
21													
													$ 13,658,240

Notes:

1 Burner system includes burner, fuel train/control valves, blower.

2 Burner system includes burner, fuel train/control valves, blower.

3 Panels for Smaller Burners. Actual configuration of panels will depend on detailed systems control analysis.

4 Panels for Larger Burners. Actual configuration of panels will depend on detailed systems control analysis.

5.0 Installed Equipment Costs for HSM Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

5.1 Baseline Cost of Fuel -2010

Total Usage	5,930,934	MMBtu/yr						
Baseline NG	2,801,957	MMBtu/yr	NG HHV	1012	NG	0 0006	1,661.24	lbs /yr
Baseline COG	3,128,978	MMBtu/yr	BFG HHV	89	COG	1.431	4,478,450.16	lbs /yr
Baseline BFG	-	MMBtu/yr	COB HHV	496	BFG	0.08279	-	lbs /yr
Annual Hours Operation	8,760	hrs/yr				Total	4,480,111	lbs /yr
Cost NG	$ 4.89	(Based on 2010 cost)					2,240.06	tons/yr
Cost COG	$ 2.92	(Based on 2010 Cost)						
Baseline Annual Cost	$ 22,838,183	(Cost NG and COG)						

5.2 Fuel Use After Fuel Switch

Total Rating	5,930,934	MMBtu/yr						
Post Fuel Switch NG	5,930,934	MMBtu/yr	NG HHV	1012	NG	0 0006	3,516.36	lbs /yr
Post Fuel Switch COG	-	MMBtu/yr	BFG HHV	89	COG	1.431	-	lbs /yr
Post Fuel Switch BFG	-	MMBtu/yr	COG HHV	496	BFG	0.082787	-	lbs /yr
Annual Hours Operation	8,760	hrs/yr				Total	3,516	lbs /yr
Cost NG	$ 5.16	(Based on average EIA Short-Term Projection for 2014/2015)					1.76	tons /yr
Future Projected Annual Cost	$ 30,603,622	(Cost NG and COG)						
			Post Fuel Switch SO_2 Emission Reduction				2,238.3	tpy
					Post Control SO_2 Factor:		0 0006	lb/MMBtu

5.3 Baseline Fuel Cost - Fuel Swich Fuel Cost

$ 7,765,439

3.0 Operating Labor Cost

Burners	$ 18,980	26 $/hr	730	1 hr/shift x 2 shifts x 365 day/yr
Other	$ -	26 $/hr	0	-
Annual Total Operating Labor	**$ 18,980**			

4.0 Maintenance

Total Installed Direct Cost	$ 4,327,217	
Total Maintenance Materials	$ 108,180	Note 2
Total Maintenance Labor	$ 108,180	Note 2
Total Annual Maintenance Cost	**$ 216,361**	Note 3
TOTAL LABOR AND MATERIALS	**$ 8,000,779**	

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
4. Fuel SO_2 emission factors from 2013 Air Inventory.
5. Actual rating is 2660 MMBtu/hr. Firing rate adjusted using 2013 emission factors to reach the PTE of 620.6 lb/hr (2713 tpy).

Table B7b. Direct and Indirect Installation Costs, Boiler House #1 - Wet Scrubber

Cost Item	Factor		Cost
Direct Costs			
Purchased Equipment Costs			
Primary Equipment[1]		$	19,555,261
Ancilliary Equipment		$	-
Allowance for Unforseen		$	1,955,526
Instrumentation	0.04	$	860,431.46
Sales Taxes	0.06	$	1,290,647.19
Freight	0.05	$	1,075,539.33
Purchased Equipment Cost, PEC		$	24,737,405
Direct Installation Costs			
Foundations and Supports[2]	0.02	$	494,748
Handling and Erection	0.68	$	14,559,588
Electrical	0.011	$	236,619
Piping	0.01	$	215,108
Ductwork	0.03	$	677,589.78
Painting	0.01	$	107,554
Direct Installation Costs, DC		$	16,291,207
Site Preparation		$	20,000
Buildings		$	-
Total Direct Costs (PEC + DC)		$	41,048,611
Indirect Costs (Installation)			
Engineering	0.15	$	3,710,611
Construction an Field Expenses	0.1	$	2,473,740
Contractor Fees	0.1	$	2,473,740
Startup	0.01	$	148,424
Performance Test	0.003	$	74,212
Model Study	0.005	$	123,687
Contingencies	0.1	$	2,473,740
Total Indirect Costs, IC		$	11,478,156
Total Installed Cost		***$***	***52,526,767***

[1] Primary equipment includes wet scrubber system. Associated equipment includes flue gas handling system, ID fans, and GEP stack.

[2] Due to the high water table at this location, it is probable that piling foundationss will be required for installation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required to determine the scope of the piling effort.

Table B7a. Annual Cost Factors, Boiler House #1 - Wet Scrubber

Cost Item			**Factor**		**Cost**
Direct Annual Costs, DC					
	Operating Labor				
		Operator	General Operating	$	333,970
		Supervisor	15% of Operator	$	50,096
		Material	0.5% of General Operation	$	1,670
	Maintenance				
		Maintenance Employee	General Maintenance	$	871,858
		Supervisor	15% of Maintenance Labor	$	153,857
		Material	100% of Maintenance Labor	$	1,025,715
	Utilities				
		Electricity		$	375,201
		Water		$	21,024
	Reagents		Limestone	$	34,288
	Sludge Disposal		Gypsum sludge	$	61,350
	Wastewater Disposal[1]				-
Indirect Annual Costs, IC					
	Administrative Charges		2% of Total Capital Investment	$	1,050,535
	Property Tax		1% of Total Capital Investment	$	525,268
	Insurance		1% of Total Capital Investment	$	525,268
	Overhead		60% of total Labor and Materials	$	1,851,024
	Capital Recovery[2]		0.1098 x Total Capital Investment	$	5,767,439
Total Annual Cost				$	12,648,563
			2010 Uncontrolled SO_2 Actual Emissions (tpy)		*407.4*
			Allowance for Uncontrolled Maint. Outages (tpy) - 15 days		*19.3*
			Control Effectiveness		*80%*
			Post-Control SO_2 Emission Factor (lb/MMBtu)		*0.026*
			Cost Per Ton SO_2 Removed	**$**	**40,747**

[1] It not know whether wastewater treatment will be technically feasible. The potential for the facility to discharge process wastewtater is limited, and would likely required construction of a new wastewater treatment system specifically for this project. Further technical feasibility evaluation is required beyond the scope of this assessment.

[2] Captal Recover Factor is derived from *EPA Air Pollution Control Manual* , Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, p. 2-21, based on 15 year equipment service life.

3. Installed Equipment Costs for Boiler House #1 Wet Scrubber

Summary of Equipment Included in Estimate

KJ 2-12-14

1 This option involves the addition of a new wet scrubber (flue gas desulfurization unit) system. The existing stacks will be tied into a new duct system to the wet scrubber, and a new stack. Due to plot plan limitations there will need to be a 450 ft flue gas handling system run from the boiler house to the stack. The rack will be elevated 30 ft above grade. A partial quench will be provided before the wet scrubber to reduce duct temperatures to 300 Deg. F. The wet scrubber includes the following components: ball mill and hydroclone system, SO_2 removal system, absorber tower, spray pumps, ID fans, waste/byproduct handling system, and thickening system. A new GEP chimney is also included.

4 Installed Equipment Costs for Boiler House #1 Wet Scrubber

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	New Stack/Chimney	1	-	-	International Chimney Corp.	1	$ 666,667	$666,667	2014	1	1	1	$ 666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	$ 104,576	$104,576	2014	1	1	1	$ 104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	$ 472,844	$472,844	2014	1	1	1	$ 472,844
4	New Fans	4	CS	CS	CUECOST (lot of 2 fans)	1	$ 534,266	$534,266	2014	1	1	1	$ 534,266
5	Tie stacks into new Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	$ 658	$361,900	2011	593	600	1	$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	$ 109,852	$109,852	2011	593	600	1	$ 111,148
7	Wet FGD Scrubber System	7	-	-	CUECOST	1	$ 17,229,088	$17,229,088	2014	1	1	1	$ 17,229,088
8	Partial Quench System	8	CS	CS	CB&I Estimate	1	$ 70,500	$70,500	2014	1	1	1	$ 70,500
9													
10													
20													
													$ 19,555,261

Notes:

1 New cost based on estimate from International Chimney Corporation, ICC File CC-42408-C, February 27, 2014. Stack is 11' 7" ID, and includes aircraft lighting, stairs, and testing platform. Stack is 213 ft high.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECost3, EPA cost model, 2014 basis. New fans sized at 254,982 acfm.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

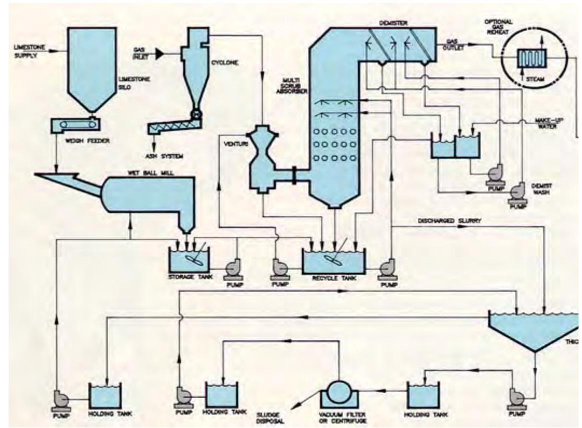
7 Cost for Wet Scrubber system based on CUECost3 EPA cost model. The wet scrubber was estimated based on an inlet flow of 330,130 acfm. The gas leaving the SDA will be quenched. The basis the outlet gas is an adiabatic saturation temperature of 127 Deg. F . A 5 Deg. F reheat at the fan is added. SO2 flow is based on 470.2 lb/hr SO2 into the wet scrubber. Equipment components included in the cost include the ball mill, hydroclone system, SO_2 removal system, absorber tower, spray pumps, ID fans, waste/byproduct handling system, and thickener.

8 Partial quench system @ 200 gpm(pumps, piping, valves, lances/nozzles, I&C).

5.0 Installed Equipment Costs for Boiler House #1 Wet Scrubber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14



1. Electricity

Fan Electricity

Flow	330130	ACFM	
Pressure Drop	8	iwc	(3 "duct, 4" WS, 1 inch stack)
Fan Efficiency	0.8	fraction	
Gas S.G. (Air = 1)	1		Use 1
Belt Efficiency	1		Typical Efficiencies
Motor Efficiency	0.95		Motor *1kW - 0.4*
Power (BHP)	519	BHP	Motor *10 kW - 0.87*
Motor Efficiency	95	%	
Power (KW)	407.7	KW	Motor *100 kW - 0.92*
Electricity Cost ($/KW-hr)	$ 0.06		Belt *1 kW - 0.78*
Hours Operated/Yr	8760	hr	Belt *10 kW - 0.88*
Annual Electricity Cost ($)	$ 214,288		Belt *100 kW - 0.93*

Pumping

Pumping Rate	200	gpm
TDH	200	ft
Pump Efficiency	75%	
Motor Efficiency	92%	
Annual Hours of Operation	8760	hr/yr
Electricity Cost ($/KW-hr)	0.06	$/Kw-hr
Brake Horsepower	7.59	BHP
Annual Electricity Cost	$ 3,233.48	($/year)

Electricity Other Uses

Other electricity	300	KW	Estimate from CUECost output
Electricity Cost ($/KW-hr)	$ 0.06	$/KW-hr	
Hours Operated/Yr	8760	hr	
Annual Electricity Cost ($)	$ 157,680.00		
Total Electricity Cost ($)	**$ 375,201.00**		

2.0 Water Costs

Partial Quench System

Estimated Water Use (gpm)	200	gpm	Water primarily evaporated in wet scrubber + blowdown
Hours Per Year	8760	hr/year	
Annual Gallons	105,120,000	gal/yr	
Water Cost ($/kgal)	$ 0.20	$/kgal	
Annual Water Cost	**$ 21,024.00**		

2.0 Operating Labor Cost

		Labor Cost	Labor (hr/yr)	Comment
FGD System	$ 324,480.00	26 $/hr	12480	Note 6
Stack	$ 9,490.00	26 $/hr	365	1 hr/day x 365 day/yr
Misc.	$ -			
Supervision	$ 50,095.50	Note 1		
Annual Total Operating Labor	**$ 384,065.50**			

3.0 Maintenance

Total Installed Direct Cost	$ 41,028,611	
Total Maintenance Materials	$ 1,025,715	Note 2
Total Maintenance Labor	$ 1,025,715	Note 2
Total Annual Maintenance Cost	**$ 2,051,431**	

4.0 Reagents

Limestone Reagent Purity	90	%	
SO2 to Absorber	470.2	tons/yr	
SO2 to Absorber	1.7	lb-mol SO2/hr	
Operating Hours	8760	hr	
Lime Requirement (100% basis)	882	tons/yr	
Actual Lime Requirement	980	tons/yr	
Limestone Unit Cost (delivered)	35	$/ton	
Annual Limestone Cost	**$ 34,288**	$/year	Note 4

Calculate Temperature Profile Through APC System

	Flow	Temperature (F)	
Initial Flow	438,726	550	
Scrubber Inlet	330,130	300	
Scrubber Outlet	254,982	127	FGD Quenching effect
Other APC	254,982	127	
Fan Outlet	257,154	132	ID Fan Reheat = 5 Deg. F

5.0 Installed Equipment Costs for Boiler House #1 Wet Scrubber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

5.0 Disposal

Annual Limestone Use	882	ton/yr	Note 5
Impurity	98	ton/yr	
Waste gypsum + Inerts	1614.48	tons	
Cost Disposal	38	$/ton	
Annual Disposal Cost	**61,350**	$/yr	

TOTAL LABOR AND MATERIALS	**$ 3,085,039**

<u>Notes:</u>

1. Supervisory labor derived from Guidance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
4. Limestone cost based on material balance assuming 90% typical lime purity. NSR Ca SO2 of 1.2 used for calculation.
5. Cost based on $38/ton disposal cost. Calculation assumes particulate from combustin of the COG and NG is negligible.
6. FGD operators include two operators plus one lab chemist per shift for total of 6 operators.

Table B8b. Direct and Indirect Installation Costs, Boiler House #2 - Wet Scrubber

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment[1]		$ 22,879,565
Ancilliary Equipment		$ -
Allowance for Unforseen		$ 2,287,956
Instrumentation	0.04	$ 1,006,700.85
Sales Taxes	0.06	$ 1,510,051.28
Freight	0.05	$ 1,258,376
Purchased Equipment Cost, PEC		$ 28,942,649
Direct Installation Costs		
Foundations and Supports[2]	0.02	$ 578,852.99
Handling and Erection	0.65	$ 16,453,930
Electrical	0.011	$ 276,842.73
Piping	0.01	$ 251,675.21
Ductwork	0.05	$ 1,258,376.06
Painting	0.01	$ 125,837.61
Direct Installation Costs, DC		$ 18,945,515
Site Preparation		$ 20,000
Buildings		$ -
Total Direct Costs (PEC + DC)		$ 47,908,164
Indirect Costs (Installation)		
Engineering	0.15	$ 4,341,397
Construction an Field Expenses	0.1	$ 2,894,265
Contractor Fees	0.1	$ 2,894,265
Startup	0.01	$ 173,656
Performance Test	0.003	$ 86,828
Model Study	0.005	$ 144,713
Contingencies	0.1	$ 2,894,265
Total Indirect Costs, IC		$ 13,429,389
Total Installed Cost		***$ 61,337,554***

[1] Primary equipment includes wet scrubber system. Associated equipment includes flue gas handling system, ID fans, and GEP stack.

[2] Due to the high water table at this location, it is probable that piling foundationss will be required for installation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required to determine the scope of the piling effort.

Table B8a. Annual Cost Factors, Boiler House #2 - Wet Scrubber

Cost Item			Factor		Cost
Direct Annual Costs, DC					
	Operating Labor				
		Operator	General Operating	$	333,970
		Supervisor	15% of Operator	$	50,096
		Material	0.5% of General Operation	$	1,670
	Maintenance				
		Maintenance Employee	General Maintenance	$	1,017,623
		Supervisor	15% of Maintenance Labor	$	179,581
		Material	100% of Maintenance Labor	$	1,197,204
	Utilities				
		Electricity		$	457,932
		Water		$	2,521
	Reagents		Limestone	$	27,198
	Sludge Disposal		Gypsum sludge	$	48,664
	Wastewater Disposal[1]				-
Indirect Annual Costs, IC					
	Administrative Charges		2% of Total Capital Investment	$	1,226,751
	Property Tax		1% of Total Capital Investment	$	613,376
	Insurance		1% of Total Capital Investment	$	613,376
	Overhead		60% of total Labor and Materials	$	2,099,249
	Capital Recovery[2]		0.1098 x Total Capital Investment	$	6,734,863
Total Annual Cost				$	14,604,073
			2010 Uncontrolled SO_2 Actual Emissions (tpy)		*750.0*
			Allowance for Uncontrolled Maint. Outages (tpy) - 15 days		*15.3*
			Control Effectiveness		*80%*
			Post-Control SO_2 Emission Factor (lb/MMBtu)		*0.037*
			Cost Per Ton SO_2 Removed	**$**	**24,848**

[1] It not know whether wastewater treatment will be technically feasible. The potential for the facility to discharge process wastewtater is limited, and would likely required construction of a new wastewater treatment system specifically for this project. Further technical feasibility evaluation is required beyond the scope of this assessment.

[2] Captal Recover Factor is derived from *EPA Air Pollution Control Manual* , Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, p. 2-21, based on 15 year equipment service life.

3. Installed Equipment Costs for Boiler House #2 Wet Scrubber

Summary of Equipment Included in Estimate KJ 2-12-14

1 This option involves the addition of a new wet scrubber (flue gas desulfurization unit) system. The existing stacks will be tied into a new duct system to the wet scrubber, and a new stack. Due to plot plan limitations there will need to be a 450 ft flue gas handling system run from the boiler house to the stack. The rack will be elevated 30 ft above grade. A partial quench will be provided before the wet scrubber to reduce duct temperatures to 300 Deg. F. The wet scrubber includes the following components: ball mill and hydroclone system, SO_2 removal system, absorber tower, spray pumps, ID fans, waste/byproduct handling system, and thickening system. A new GEP chimney is also included.

4 Installed Equipment Costs for Boiler House #2 Wet Scrubber

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	New Stack/Chimney	1	-	-	International Chimney Corp.	1	$ 666,667	$666,667	2014	1	1	1	$ 666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	$ 104,576	$104,576	2014	1	1	1	$ 104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	$ 472,844	$472,844	2014	1	1	1	$ 472,844
4	New Fans	4	CS	CS	CUECOST (lot of 2 fans)	1	$ 607,720	$607,720	2014	1	1	1	$ 607,720
5	Tie stacks into new Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	$ 658	$361,900	2011	593	600	1	$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	$ 109,852	$109,852	2011	593	600	1	$ 111,148
7	Wet FGD Scrubber System	7	-	-	CUECOST	1	$ 20,479,938	$20,479,938	2014	1	1	1	$ 20,479,938
8	Partial Quench System	8	CS	CS	CB&I Estimate	1	$ 70,500	$70,500	2014	1	1	1	$ 70,500
9													
10													
20													
													$ 22,879,565

Notes:

1 Estimate for self supporting stack, 12'10" ID, including aircraft warning lights, ladder, and testing platform. Pricing from International chimney Corporation, ICC File CC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECost3, EPA cost model, 2014 basis. Flow to fan is 313,972 acfm at 127 Deg. F.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Cost for Wet Scrubber system based on CUECost3 EPA cost model. The wet scrubber was estimated based on an inlet flow of 540,025 acfm. The gas leaving the wet scrubber will be quenched. The basis the outlet gas is an adiabatic saturation temperature of 127 Deg. F . A 5 Deg. F reheat at the fan is added. SO2 flow is based on 373 lb/hr SO2 into the wet scrubber. Equipment components included in the cost include the ball mill, hydroclone system, SO_2 removal system, absorber tower, spray pumps, ID fans, waste/byproduct handling system, and thickener.

8 Partial quench system @ 200 gpm(pumps, piping, valves, lances/nozzles, I&C).

5.0 Installed Equipment Costs for Boiler House #2 Wet Scrubber

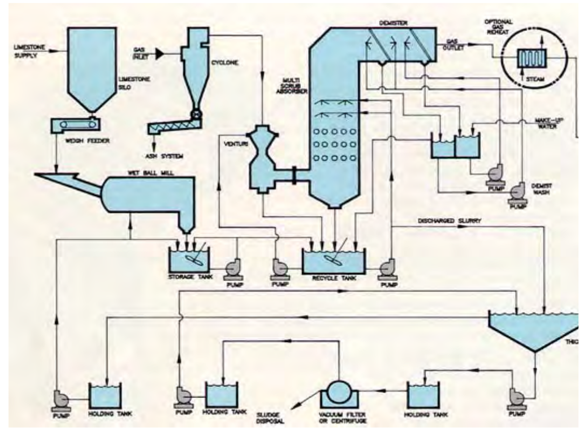
Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity

Fan Electricity

Flow	417098	ACFM	
Pressure Drop	8	iwc	(3 "duct, 4" WS, 1 inch stack)
Fan Efficiency	0.8	fraction	
Gas S.G. (Air = 1)	1		Air = .075 lb/ft3 @ 70 Deg. F
Belt Efficiency	1		Typical Efficiencies
Motor Efficiency	0.95		Motor *1kW - 0.4*
Power (BHP)	656	BHP	Motor *10 kW - 0.87*
Motor Efficiency	95	%	
Power (KW)	515.1	KW	Motor *100 kW - 0.92*
Electricity Cost ($/KW-hr)	$ 0.06		Belt *1 kW - 0.78*
Hours Operated/Yr	8760	hr	Belt *10 kW - 0.88*
Annual Electricity Cost ($)	$ 270,738		Belt *100 kW - 0.93*



Pumping

Pumping Rate	200	gpm
TDH	200	ft
Pump Efficiency	75%	
Motor Efficiency	92%	
Annual Hours of Operation	8760	hr/yr
Electricity Cost ($/KW-hr)	0.06	$/Kw-hr
Brake Horsepower	7.59	BHP
Annual Electricity Cost	$ 3,233.48	($/year)

Electricity Other Uses

Other Electricity	350	KW	Estimate from CUECost3
Electricity Cost ($/KW-hr)	$ 0.06	$/KW-hr	
Hours Operated/Yr	8760	hr	
Annual Electricity Cost ($)	$ 183,960.00		
Total Electricity Cost ($)	**$ 457,931.97**		

2.0 Water Costs

Partial Quench System

Estimated Water Use (gpm)	200	gpm	Water primarily evaporated in wet scrubber + blowdown
Hours Per Year	8760	hr/year	
Annual Gallons	12,604,317	gal/yr	
Water Cost ($/kgal)	$ 0.20	$/kgal	
Annual Water Cost	**$ 2,520.86**		

3.0 Operating Labor Cost

			Labor Cost	**Labor (hr/yr)**	**Comment**
FGD System	$ 324,480.00		26 $/hr	12480	Note 6
Stack	$ 9,490.00		26 $/hr	365	1 hr/day x 365 day/yr
Misc.	$ -				
Supervision	$ 50,095.50	Note 1			
Annual Total Operating Labor	**$ 384,065.50**				

4.0 Maintenance

Total Installed Direct Cost	$ 47,888,164	
Total Maintenance Materials	$ 1,197,204	Note 2
Total Maintenance Labor	$ 1,197,204	Note 2
Total Annual Maintenance Cost	**$ 2,394,408**	

5.0 Reagents

Limestone Reagent Purity	90	%	
SO2 to Absorber	373.0	tons/yr	
SO2 to Absorber	1.3	lb-mol SO2/hr	
Operating Hours	8760	hr	
Lime Requirement (100% basis)	699	tons/yr	
Actual Lime Requirement	777	tons/yr	
Limestone Unit Cost (delivered)	35	$/ton	
Annual Limestone Cost	**$ 27,198**	$/year	Note 4

2.0 Calculate Temperature Profile Through APC System

	Flow	Temperature	
Initial Flow	540,225	550	
Scrubber Inlet	406,506	300	
Scrubber Outlet	313,972	127	FGD Quenching effect
Other APC	313,972	127	
Fan Outlet	316,647	132	ID Fan Reheat = 5 Deg. F

5.0 Installed Equipment Costs for Boiler House #2 Wet Scrubber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

6.0 Disposal

Annual Limestone Use	699	ton/yr	Note 5
Impurity	78	ton/yr	
Waste gypsum + Inerts	1280.63	tons	
Cost Disposal	38	$/ton	
Annual Disposal Cost	**48,664**	$/yr	

TOTAL LABOR AND MATERIALS	**$ 3,498,749**

Notes:

1. Supervisory labor derived from Guidance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
4. Limestone cost based on material balance assuming 90% typical lime purity. NSR Ca SO2 of 1.2 used for calculation.
5. Cost based on $38/ton disposal cost. Calculation assumes particulate from combustin of the COG and NG is negligible.
6. FGD operators include two operators plus one lab chemist per shift for total of 6 operators.

Table B9b. Direct and Indirect Installation Costs, HSM Furnaces - Wet Scrubber

Cost Item	**Factor**	**Cost**
Direct Costs		
Purchased Equipment Costs		
Primary Equipment[1]		$ 24,846,340
Ancilliary Equipment		$ -
Allowance for Unforseen		$ 2,559,774
Instrumentation	0.04	$ 1,096,245
Sales Taxes	0.06	$ 1,644,367
Freight	0.05	$ 1,370,306
Purchased Equipment Cost, PEC		$ 31,517,031
Direct Installation Costs		
Foundations and Supports[2]	0.02	$ 630,340.63
Handling and Erection	0.61	$ 19,243,882
Electrical	0.011	$ 346,687
Piping	0.01	$ 409,721
Ductwork	0.04	$ 1,304,805
Painting	0.01	$ 157,585
Direct Installation Costs, DC		$ 22,093,022
Site Preparation		$ 20,000
Buildings		$ -
Total Direct Costs (PEC + DC)		$ 53,630,053
Indirect Costs (Installation)		
Engineering	0.15	$ 4,727,555
Construction an Field Expenses	0.1	$ 3,151,703
Contractor Fees	0.1	$ 3,151,703
Startup	0.01	$ 189,102
Performance Test	0.003	$ 94,551
Model Study	0.005	$ 157,585
Contingencies	0.1	$ 3,151,703
Total Indirect Costs, IC		$ 14,623,903
Total Installed Cost		***$ 68,253,956***

[1] Primary equipment includes wet scrubber system. Associated equipment includes flue gas handling system, ID fans, and GEP stack.

[2] Due to the high water table at this location, it is probable that piling foundationss will be required for installation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required to determine the scope of the piling effort.

Table B9a. Annual Cost Factors, HSM Furnaces - Wet Scrubber

Cost Item	Factor		Cost
Direct Annual Costs, DC			
Operating Labor			
Operator	General Operating	$	333,970
Supervisor	15% of Operator	$	50,096
Material	0.5% of General Operation	$	1,670
Maintenance			
Maintenance Employee	General Maintenance	$	1,139,214
Supervisor	15% of Maintenance Labor	$	201,038
Material	100% of Maintenance Labor	$	1,340,251
Utilities			
Electricity		$	682,755
Water		$	42,048
Reagents	Limestone	$	197,823
Sludge Disposal	Gypsum sludge	$	353,956
Wastewater Disposal[1]			-
Indirect Annual Costs, IC			
Administrative Charges	2% of Total Capital Investment	$	1,365,079
Property Tax	1% of Total Capital Investment	$	682,540
Insurance	1% of Total Capital Investment	$	682,540
Overhead	60% of total Labor and Materials	$	2,762,370
Capital Recovery[2]	0.1098 x Total Capital Investment	$	7,494,284
Total Annual Cost		$	17,329,633
	2010 Uncontrolled SO_2 Actual Emissions (tpy)		*2240.1*
	Allowance for Uncontrolled Maint. Outages (tpy) - 15 days		*111.7*
	Control Effectiveness		*80%*
	Post-Control SO_2 Emission Factor (lb/MMBtu)		*0.046*
	Cost Per Ton SO_2 Removed	**$**	**10,178**

[1] It not know whether wastewater treatment will be technically feasible. The potential for the facility to discharge process wastewtater is limited, and would likely required construction of a new wastewater treatment system specifically for this project. Further technical feasibility evaluation is required beyond the scope of this assessment.

[2] Captal Recover Factor is derived from *EPA Air Pollution Control Manual* , Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, p. 2-21, based on 15 year equipment service life.

3. Installed Equipment Costs for HSM Furnaces Wet Scrubber

Summary of Equipment Included in Estimate KJ 2-12-14

1 This option involves the addition of a new wet scrubber (flue gas desulfurization unit) system. The existing stacks will be tied into a new duct system to the wet scrubber, and a new stack. Due to plot plan limitations there will need to be a 450 ft flue gas handling system run from the boiler house to the stack. The rack will be elevated 30 ft above grade. A partial quench will be provided before the wet scrubber to reduce duct temperatures to 300 Deg. F. The wet scrubber includes the following components: ball mill and hydroclone system, SO_2 removal system, absorber tower, spray pumps, ID fans, waste/byproduct handling system, and thickening system. A new GEP chimney is also included.

4 Installed Equipment Costs for HSM Furnaces Wet Scrubber

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	New Stack/Chimney	1	-	-	International Chimney Corp.	1	$ 833,333	$833,333	2014	1	1	1	$ 833,333
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	2	$ 104,576	$209,152	2014	1	1	1	$ 209,152
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	2	$ 472,844	$945,688	2014	1	1	1	$ 945,688
4	New Fans	4	CS	CS	CUECOST (lot of 2 fans)	1	$ 941,668	$941,668	2014	1	1	1	$ 941,668
5	Tie stacks into new Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	$ 658	$361,900	2011	593	600	1	$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	$ 109,852	$109,852	2011	593	600	1	$ 111,148
7	Wet FGD Scrubber System	7	-	-	CUECOST	1	$ 22,120,076	$22,120,076	2014	1	1	1	$ 22,120,076
8	Partial Quench System	8	CS	CS	CB&I Estimate	1	$ 70,500	$70,500	2014	1	1	1	$ 70,500
9													
10													
11													
12													
13													
14	***Known Installation Costs to Be Factored In***		***Amt***		***Basis***								
15	Chimney and General Facilities (total direct)		$ 2,500,000		International Chimney Corp.								
16	New Structural Ductwork (total direct)		$ 1,782,294		CB&I Estimate								
17	Wet FGD Scrubber System		$ 38,046,531		CUECOST (2014 basis)								
	Tie In to Structural Ductwork		$ 676,172		CB&I Estimate								
18	Fans (2)		$ 1,783,218		CUECOST (2014 basis)								
19	Partial Quench System		$ 211,000.00		CB&I Estimate								
20													
													$ 25,597,738

Notes:

1 Estimate for self supporting column (concrete with block lining), 16' 10" diameter, including aircraft lights, ladder and testing platform. Pricing from International Chimney Corporation, ICC File CC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECost3, EPA cost model, 2014 basis. Flow to fan is 637,017 acfm at 127 Deg. F.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Cost for Wet Scrubber system based on CUECost3 EPA cost model. The wet scrubber was estimated based on an inlet flow of 824,758 acfm. The gas leaving the wet scrubber will be quenched. The basis the outlet gas is an adiabatic saturation temperature of 127 Deg. F . A 5 Deg. F reheat at the fan is added. SO2 flow is based on 620.9 lb/hr SO2 into the wet scrubber. Equipment components included in the cost include the ball mill, hydroclone system, SO_2 removal system, absorber tower, spray pumps, ID fans, waste/byproduct handling system, and thickener.

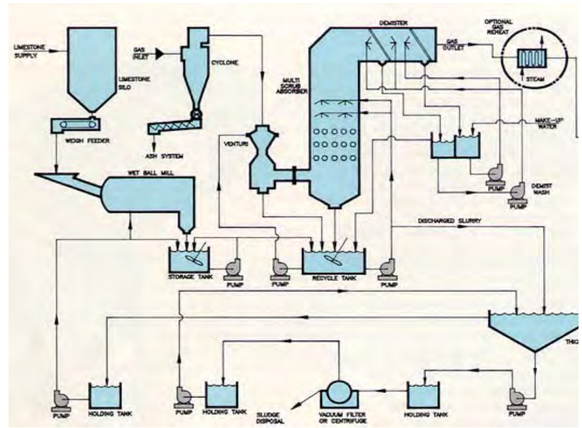
8 Partial quench system @ 200 gpm(pumps, piping, valves, lances/nozzles, I&C).

5.0 Installed Equipment Costs for HSM Furnaces Wet Scrubber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity



Fan Electricity

Flow	637,017	ACFM	
Pressure Drop	8	iwc	(3 "duct, 4" WS, 1 inch stack)
Fan Efficiency	0.8	fraction	
Gas S.G. (Air = 1)	1		Air = .075 lb/ft3 @ 70 Deg. F
Belt Efficiency	1		Typical Efficiencies
Motor Efficiency	0.95		Motor *1kW - 0.4*
Power (BHP)	1002	BHP	Motor *10 kW - 0.87*
Motor Efficiency	95	%	
Power (KW)	786.7	KW	Motor *100 kW - 0.92*
Electricity Cost ($/KW-hr)	$ 0.06		Belt *1 kW - 0.78*
Hours Operated/Yr	8760	hr	Belt *10 kW - 0.88*
Annual Electricity Cost ($)	$ 413,488		Belt *100 kW - 0.93*

Pumping

Pumping Rate	400	gpm
TDH	200	ft
Pump Efficiency	75%	
Motor Efficiency	92%	
Annual Hours of Operation	8760	hr/yr
Electricity Cost ($/KW-hr)	0.06	$/Kw-hr
Brake Horsepower	15.18	BHP
Annual Electricity Cost	$ 6,466.96	($/year)

Electricity Other Uses

Other Electricity	500	KW	Estimate from CUECost3
Electricity Cost ($/KW-hr)	$ 0.06	$/KW-hr	
Hours Operated/Yr	8760	hr	
Annual Electricity Cost ($)	$ 262,800.00		

Total Electricity Cost ($)	**$ 682,754.96**

2.0 Water Costs

Partial Quench System

Estimated Water Use (gpm)	400	gpm	Water primarily evaporated in wet scrubber + blowdown
Hours Per Year	8760	hr/year	
Annual Gallons	210,240,000	gal/yr	
Water Cost ($/kgal)	$ 0.20	$/kgal	
Annual Water Cost	**$ 42,048.00**		

2.0 Operating Labor Cost

		Labor Cost	Labor (hr/yr)	Comment
FGD System	$ 324,480.00	26 $/hr	12480	Note 6
Stack	$ 9,490.00	26 $/hr	365	1 hr/day x 365 day/yr
Misc.	$ -			
Supervision	$ 50,095.50	Note 1		
Annual Total Operating Labor	**$ 384,065.50**			

3.0 Maintenance

Total Installed Direct Cost	$ 53,610,053	
Total Maintenance Materials	$ 1,340,251	Note 2
Total Maintenance Labor	$ 1,340,251	Note 2
Total Annual Maintenance Cost	**$ 2,680,503**	

4.0 Reagents

Limestone Reagent Purity	90	%	
SO2 to Absorber	2713.0	tons/yr	
SO2 to Absorber	9.7	lb-mol SO2/hr	
Operating Hours	8760	hr	
Lime Requirement (100% basis)	5087	tons/yr	
Actual Lime Requirement	5652	tons/yr	
Limestone Unit Cost (delivered)	35	$/ton	
Annual Limestone Cost	**$ 197,823**	$/year	Note 4

2.0 Calculate Temperature Profile Through APC System

	Flow	Temperature	
Furnace Outlet	933,279	400	
Scrubber Inlet	824,758	300	
Scrubber Outlet	637,017	127	FGD Quenching effect
Other APC	637,017	127	
Fan Outlet	642,443	132	ID Fan Reheat = 5 Deg. F

5.0 Disposal

5.0 Installed Equipment Costs for HSM Furnaces Wet Scrubber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

Annual Limestone Use	5,087	ton/yr	Note 5
Impurity	565	ton/yr	
Waste gypsum + Inerts	9314.63	tons	
Cost Disposal	38	$/ton	
Annual Disposal Cost	**353,956**	$/yr	

TOTAL LABOR AND MATERIALS	**$ 4,603,950**

Notes:

1. Supervisory labor derived from Guidance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
4. Limestone cost based on material balance assuming 90% typical lime purity. NSR Ca SO2 of 1.2 used for calculation.
5. Cost based on $38/ton disposal cost. Calculation assumes particulate from combustin of the COG and NG is negligible.
6. FGD operators include two operators plus one lab chemist per shift for total of 6 operators.

Table B10b. Direct and Indirect Installation Costs, Boiler House #1 - Spray Dryer Absorber

Cost Item	Factor	Factor	Cost
Direct Costs			
Purchased Equipment Costs			
Primary Equipment[1]			$ 16,765,668
Ancilliary Equipment			$ -
Allowance for Unforseen			$ 1,676,567
Instrumentation		0.04	$ 737,689.41
Sales Taxes		0.06	$ 1,106,534.11
Freight		0.05	$ 922,112
Purchased Equipment Cost, PEC			$ 21,208,570
Direct Installation Costs[2]			
Foundations and Supports		0.03	$ 461,056
Handling and Erection		0.70	$ 12,930,722
Electrical		0.009	$ 165,980
Piping		0.01	$ 221,307
Ductwork		0.05	$ 922,112
Painting		0.01	$ 92,211
Direct Installation Costs, DC			$ 14,793,387
Site Preparation			$ 20,000
Buildings			$ -
Total Direct Costs (PEC + DC)			$ 36,021,958
Indirect Costs (Installation)			
Engineering		0.15	$ 3,181,286
Construction an Field Expenses		0.1	$ 2,120,857
Contractor Fees		0.1	$ 2,120,857
Startup		0.01	$ 127,251
Performance Test		0.003	$ 63,626
Model Study		0.005	$ 106,043
Contingencies		0.1	$ 2,120,857
Total Indirect Costs, IC			$ 9,840,777
Total Installed Cost			***$ 45,862,734***

[1] Primary equipment includes spray dry absorber and pulse jet fabric filter baghouse. Auxillary equipment is included with primary equipment cost.

[2] Due to the high water table at this location, it is probable that piling foundations will be required for installation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required to determine the scope of the piling effort.

Table B10a. Annual Cost Factors, Boiler House #1 - Spray Dry Absorber

Cost Item	**Factor**	**Cost**
Direct Annual Costs, DC		
Operating Labor		
Operator	General Operating	$ 336,830
Supervisor	15% of Operator	$ 50,525
Material	0.5% of General Operation	$ 1,684
Maintenance		
Maintenance Employee	General Maintenance	$ 765,042
Supervisor	15% of Maintenance Labor	$ 135,007
Material	100% of Maintenance Labor	$ 900,049
Utilities		
Electricity		$ 71,832
Water		$ 2,521
Reagents	Lime	$ 101,612
Solids Disposal	Gypsum solids from FFBH	$ 64,026
Indirect Annual Costs, IC		
Administrative Charges	2% of Total Capital Investment	$ 917,255
Property Tax	1% of Total Capital Investment	$ 458,627
Insurance	1% of Total Capital Investment	$ 458,627
Overhead	60% of total Labor and Materials	$ 1,454,953
Capital Recovery[1]	0.1098 x Total Capital Investment	$ 5,035,728
Total Annual Cost		$ 10,754,317
	2010 Uncontrolled SO_2 Actual Emissions (tpy)	*407.4*
	Allowance for Uncontrolled Maint Outages (tpy) - 15 days	*19.3*
	SO_2 Removal Efficiency	*80%*
	Post-Control Emission Factor (lb/MMBtu)	*0.026*
	Control Cost Per Ton SO_2	**$ 34,644**

[1] Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #1 Spray Dry Absorber

Summary of Equipment Included in Estimate KJ 2-12-14

1 This option involves the addition of a new Spray Dry Absorber system and associated baghouse to collect residual carryover. The existing stacks will be tied into a new duct system to the SDA, the baghouse, and a new stack. Due to plot plan limitations this will need to a 450 ft flue gas handling system duct run from the boiler house to the stack. The duct will be elevated 30 ft above grade. Prior to entering the SDA the flue gas will be partially quenched to 300 ^{o}F. The primary SDA components include: Lime/reagent feed system, SO_2 removal system, spray dryers, ID fans, and waste/byproduct handling system. A new GEP chimney is also included. The key fabric filter components include: fabric filter enclosure, bags, and ash handling system.

4 Installed Equipment Costs for Boiler House #1 Spray Dry Absorber

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	New Stack	1	-	-	International Chimney Corp.	1	$ 666,667	$666,667	2014	1	1	1	$ 666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	$ 104,576	$104,576	2014	1	1	1	$ 104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	$ 472,844	$472,844	2014	1	1	1	$ 472,844
4	New Fans	4	CS	CS	Included with baghouse	1	$ -	$0	2014	1	1	1	$ -
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	$ 658	$361,900	2011	593	600	1	$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	$ 108,570	$108,570	2011	593	600	1	$ 109,852
7	Spray Dry Injection System	7	-	-	CUECOST	1	$ 11,793,535	$11,793,535	2014	1	1	1	$ 11,793,535
8	New FFBH for SDA system	8	-	-	CUECOST	1	$ 3,181,523	$3,181,523	2014	1	1	1	$ 3,181,523
9	Partial Quench System (to 300 F)	9	CS	CS	CB&I Estimate	1	$ 70,500	$70,500	2014	1	1	1	$ 70,500
10													
11													
													$ 16,765,668

Notes:

1 Estimate for self supporting stack, 11'7" ID, including aircraft warning lights, ladder, and testing platform. Pricing from International Chimney Corporation, ICC File CC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECost3, EPA cost model, 2014 basis. Estimate based on duct flow of 263,670 acfm at 152 Deg. F entering the IDF.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Cost for SDA system based on CUECost3 EPA cost model, 2014 basis. The SDA was estimated based on an inlet flow of 330130 acfm. The gas leaving the SDA will approach saturation temperature . The basis the outlet gas is an adiabatic saturation temperature of 127 Deg. F, with a 20 degree approach, for a SDA outlet temperature of 147 Deg. F. A 5 Deg. F reheat at the fan is added. Control costs are based on a SO2 loading of 470 ton per year to the SDA.

8 New pulse jet fabric filter baghouse based on CEUCOST 3, EPA cost model, 2014 basis. The FFBH was estimated based on a flow of 263670 acfm at 147 Deg. F. The cost is based on Pulse Jet type, and Gas-to-Cloth Ratio of 4. An ash rate of 5,000 lb/hr was used for ash handling equipment sizing, as this is a minimal value for a basic ash handling system..

9 Partial quench system @ 200 gpm (pumps, piping, valves, lances/nozzles, I&C)

5.0 Installed Equipment Costs for Boiler House #1 Spray Dry Absorber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity

Fan Electricity

Flow	330130	ACFM	
Pressure Drop	15	iwc	(3 inches duct, 5 inches SDA, 6 inches FFBH, 1 inch stack)
Fan Efficiency	0.8	fraction	
Gas S.G. (Air = 1)	1		Use 1
Belt Efficiency	1		Typical Efficiencies
Motor Efficiency	0.95		Motor *1kW - 0.4*
Power (BHP)	974	BHP	Motor *10 kW - 0.87*
Motor Efficiency	95	%	
Power (KW)	764.4	KW	Motor *100 kW - 0.92*
Electricity Cost ($/KW-hr)	$ 0.06		Belt *1 kW - 0.78*
Hours Operated/Yr	8760	hr	Belt *10 kW - 0.88*
Annual Electricity Cost ($)	$ 401,789		Belt *100 kW - 0.93*

Electricity Other Uses

From CUECOST3	120	KW	Costing from CUECOST model for FFBH
Electricity Cost ($/KW-hr)	$ 0.06		
Hours Operated/Yr	8760	hr	
Annual Electricity Cost ($)	$ 63,072.00		
Total Electricity Cost ($)	**$ 71,832.00**		

2.0 Water Costs

SDA System

Estimated Water Use (gpm)	200	gpm	Water primarily evaporated in SDA
Hours Per Year	8760		
Annual Gallons	12,604,317	gal/yr	
Water Cost ($/kgal)	$ 0.20		
Annual Water Cost	**$ 2,520.86**		

2.0 Operating Labor Cost

		Labor Cost		Labor (hr/yr)	Comment
Quench System	$ 18,980	26	$/hr	730	1 hr/shift x 2 shifts x 365 day/yr
SDA System	$ 270,400	26	$/hr	10400	Note 6
Stack	$ 9,490	26	$/hr	365	1 hr/day x 365 day/yr
Baghouse	$ 37,960	26	$/hr	1460	Inspect 2/shift x 2 * 365
Misc.	$ -				
Supervision	$ 50,525	Note 1			
Annual Total Operating Labor	**$ 387,355**				

3.0 Maintenance

Total Installed Direct Cost	$ 36,001,958	
Total Maintenance Materials	$ 900,049	Note 2
Total Maintenance Labor	$ 900,049	Note 2
Total Annual Maintenance Cost	**$ 1,800,098**	

Calculate Temperature Profile Through APC System

	Flow	Temperature	
Absorber Inlet	330,130	300	
Absorber Outlet	263,670	147	SDA quenching effect
FFBH Outlet	263,670	147	
Fan Outlet	265,842	152	ID Fan Reheat = 5 Deg F

Note: Flow prior to quench is 438,726 acfm at 550 Deg. F

4.0 Reagents

Reagent Purity	90		
SO_2 to Absorber	470.2	tons/yr	
Operating Hours	8760	hr	
Lime Requirement (100% basis)	494	tons/yr	
Actual Lime Requirement	549	tons/yr	
Lime Unit Cost	185	$/ton	
Annual Lime Cost	**$ 101,612**	$/year	Note 4

5.0 Disposal

CaO + SO2 + 1/2 O2 + 2H20 --> CaSO4*2H20

Annual Lime Use	494	ton/yr	Note 5
Impurity	55	ton/yr	
Waste gypsum + Inerts	1685	tons	
Cost Disposal	38	$/ton	
Annual Disposal Cost	**64,026**	$/yr	

TOTAL LABOR AND MATERIALS **$ 2,424,921.64**

5.0 Installed Equipment Costs for Boiler House #1 Spray Dry Absorber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
4. Lime cost based on material balance assuming 90% typical lime purity. NSR Ca:SO2 of 1.2 used for calculation.
5. Cost based on $38/ton disposal cost. Calculation assumes particulate from combustin of the COG and NG is negligible.
6. Within the utility industry, the SDA is labor intensitve. For a typical 200-500 MW application there are 16-20 operators required. This will be a slightly smaller operation that typical utility, and for purposes of this estimate a total of 10 operators is used 5 per shift.

Table B11b. Direct and Indirect Installation Costs, Boiler House #2 - Spray Dryer Absorber

Cost Item	Factor	Factor	Cost
Direct Costs			
Purchased Equipment Costs			
Primary Equipment[1]			$ 17,901,564
Ancilliary Equipment			$ -
Allowance for Unforseen			$ 1,790,156
Instrumentation		0.04	$ 787,668.83
Sales Taxes		0.06	$ 1,181,503.25
Freight		0.05	$ 984,586
Purchased Equipment Cost, PEC			$ 22,645,479
Direct Installation Costs[2]			
Foundations and Supports		0.03	$ 590,752
Handling and Erection		0.697	$ 13,728,195
Electrical		0.009	$ 177,225
Piping		0.01	$ 196,917
Ductwork		0.05	$ 984,586
Painting		0.01	$ 98,459
Direct Installation Costs, DC			$ 15,776,134
Site Preparation			$ 20,000
Buildings			$ -
Total Direct Costs (PEC + DC)			$ 38,441,613
Indirect Costs (Installation)			
Engineering		0.15	$ 3,396,822
Construction an Field Expenses		0.1	$ 2,264,548
Contractor Fees		0.1	$ 2,264,548
Startup		0.01	$ 135,873
Performance Test		0.003	$ 67,936
Model Study		0.005	$ 113,227
Contingencies		0.1	$ 2,264,548
Total Indirect Costs, IC			$ 10,507,502
Total Installed Cost			***$ 48,949,115***

[1] Primary equipment includes spray dry absorber and pulse jet fabric filter baghouse. Auxillary equipment is included with primary equipment cost.

[2] Due to the high water table at this location, it is probable that piling foundations will be required for installation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required to determine the scope of the piling effort.

Table B11a. Annual Cost Factors, Boiler House #2 - Spray Dry Absorber

Cost Item	Factor	Cost
Direct Annual Costs, DC		
Operating Labor		
Operator	General Operating	$ 336,830
Supervisor	15% of Operator	$ 50,525
Material	0.5% of General Operation	$ 1,684
Maintenance		
Maintenance Employee	General Maintenance	$ 816,459
Supervisor	15% of Maintenance Labor	$ 144,081
Material	100% of Maintenance Labor	$ 960,540
Utilities		
Electricity		$ 471,735
Water		$ 2,521
Reagents	Lime	$ 80,606
Sludge Disposal	Gypsum sludge	$ 50,790
Indirect Annual Costs, IC		
Administrative Charges	2% of Total Capital Investment	$ 978,982
Property Tax	1% of Total Capital Investment	$ 489,491
Insurance	1% of Total Capital Investment	$ 489,491
Overhead	60% of total Labor and Materials	$ 1,746,940
Capital Recovery[1]	0.1098 x Total Capital Investment	$ 5,374,613
Total Annual Cost		$ 11,995,290
	2010 Uncontrolled SO_2 Actual Emissions (tpy)	*750.4*
	Allowance for Uncontrolled Maint Outages (tpy) - 15 days	*15.3*
	SO_2 Removal Efficiency	*80%*
	Post-Control Emission Factor (lb/MMBtu)	*0.037*
	Control Cost Per Ton SO_2	**$ 20,400**

[1] Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #2 Spray Dry Absorber

Summary of Equipment Included in Estimate KJ 2-12-14

1 This option involves the addition of a new Spray Dry Absorber system and associated baghouse to collect residual carryover. The existing stacks will be tied into a new duct system to the SDA, the baghouse, and a new stack. Due to plot plan limitations this will need to a 450 ft flue gas handling system duct run from the boiler house to the stack. The duct will be elevated 30 ft above grade. Prior to entering the SDA the flue gas will be partially quenched to 300 ^{o}F. The primary SDA components include: Lime/reagent feed system, SO_2 removal system, spray dryers, ID fans, and waste/byproduct handling system. A new GEP chimney is also included. The key fabric filter components include: fabric filter enclosure, bags, and ash handling system.

4 Installed Equipment Costs for Boiler House #2 Spray Dry Absorber

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	New Stack	1	-	-	International Chimney Corp.	1	$ 666,667	$666,667	2014	1	1	1	$ 666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	$ 104,576	$104,576	2014	1	1	1	$ 104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	$ 472,844	$472,844	2014	1	1	1	$ 472,844
4	New Fans	4	CS	CS	Included with baghouse	1	$ -	$0	2014	1	1	1	$ -
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	$ 658	$361,900	2011	593	600	1	$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	$ 108,570	$108,570	2011	593	600	1	$ 109,852
7	Spray Dry Injection System	7	-	-	CUECOST	1	$ 12,477,234	$12,477,234	2014	1	1	1	$ 12,477,234
8	New FFBH for SDA system	8	-	-	CUECOST	1	$ 3,633,720	$3,633,720	2014	1	1	1	$ 3,633,720
9	Partial Quench System (to 300 F)	9	CS	CS	CB&I Estimate	1	$ 70,500	$70,500	2014	1	1	1	$ 70,500
10													
11													
													$ 17,901,564

Notes:

1 Estimate for self supporting stack, 12'10" ID, including aircraft warning lights, ladder, and testing platform. Pricing from International Chimney Corporation, ICC File CC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECost3, EPA cost model, 2014 basis. Estimate based on duct flow of 324,550 acfm at 147 Deg. F entering the IDF.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Cost for SDA system based on CUECost3 EPA cost model, 2014 basis. The SDA was estimated based on an inlet flow of 406,355 acfm. The gas leaving the SDA will approach saturation temperature .
The basis the outlet gas is an adiabatic saturation temperature of 127 Deg. F, with a 20 degree approach, for a SDA outlet temperature of 147 Deg. F. A 5 Deg. F reheat at the fan is added.
Control costs are based on a SO_2 loading of 373 ton per year to the SDA.

8 New pulse jet fabric filter baghouse based on CEUCOST 3, EPA cost model, 2014 basis. The FFBH was estimated based on a flow of 324,550 acfm at 147 Deg. F. The cost is based on Pulse Jet type, and Gas-to-Cloth Ratio of 4.
An ash rate of 5,000 lb/hr was used for ash handling equipment sizing, as this is a minimal value for a basic ash handling system..

9 Partial quench system @ 200 gpm (pumps, piping, valves, lances/nozzles, I&C)

5.0 Installed Equipment Costs for Boiler House #2 Spray Dry Absorber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity

Fan Electricity

Flow	324550	ACFM	
Pressure Drop	15	iwc	(3 inches duct, 5 inches SDA, 6 inches FFBH, 1 inch stack)
Fan Efficiency	0.8	fraction	
Gas S.G. (Air = 1)	1		Use 1
Belt Efficiency	1		Typical Efficiencies
Motor Efficiency	0.95		Motor *1kW - 0.4*
Power (BHP)	957	BHP	Motor *10 kW - 0.87*
Motor Efficiency	95	%	
Power (KW)	751.5	KW	Motor *100 kW - 0.92*
Electricity Cost ($/KW-hr)	$ 0.06		Belt *1 kW - 0.78*
Hours Operated/Yr	8760	hr	Belt *10 kW - 0.88*
Annual Electricity Cost ($)	$ 394,998		Belt *100 kW - 0.93*

Electricity Other Uses

From CEUCOST3	146	KW	Costing from CUECOST model.
Electricity Cost ($/KW-hr)	$ 0.06		
Hours Operated/Yr	8760	hr	
Annual Electricity Cost ($)	$ 76,737.60		
Total Electricity Cost ($)	**$ 471,735.49**		

2.0 Water Costs

SDA System

Estimated Water Use (gpm)	200	gpm	Water primarily evaporated in SDA
Hours Per Year	8760		
Annual Gallons	12,604,317	gal/yr	
Water Cost ($/kgal)	$ 0.20		
Annual Water Cost	**$ 2,520.86**		

2.0 Operating Labor Cost

		Labor Cost	Labor (hr/yr)	Comment
Quench System	$ 18,980	26 $/hr	730	1 hr/shift x 2 shifts x 365 day/yr
SDA System	$ 270,400	26 $/hr	10400	Note 6
Stack	$ 9,490	26 $/hr	365	1 hr/day x 365 day/yr
Baghouse	$ 37,960	26 $/hr	1460	Inspect 2/shift x 2 * 365
Misc.	$ -			
Supervision	$ 50,525	Note 1		
Annual Total Operating Labor	**$ 387,355**			

3.0 Maintenance

Total Installed Direct Cost	$ 38,421,613	
Total Maintenance Materials	$ 960,540	Note 2
Total Maintenance Labor	$ 960,540	Note 2
Total Annual Maintenance Cost	**$ 1,921,081**	

Calculate Temperature Profile Through APC System

	Flow	Temperature	
Absorber Inlet	330,130	300	
Absorber Outlet	263,670	147	SDA quenching effect
FFBH Outlet	263,670	147	
Fan Outlet	265,842	152	ID Fan Reheat = 5 Deg F

Note: Flow prior to quench is 438726 acfm at 550 Deg. F

4.0 Reagents

Reagent Purity	90		
SO2 to Absorber	373	tons/yr	
Operating Hours	8760	hr	
Lime Requirement (100% basis)	392	tons/yr	
Actual Lime Requirement	436	tons/yr	
Lime Unit Cost	185	$/ton	
Annual Lime Cost	**$ 80,606**	$/year	Note 4

5.0 Disposal

CaO + SO2 + 1/2 O2 + 2H20 --> CaSO4*2H20

Annual Lime Use	392	ton/yr	Note 5
Impurity	44	ton/yr	
Waste gypsum + Inerts	1337	tons	
Cost Disposal	38	$/ton	
Annual Disposal Cost	**50,790**	$/yr	

TOTAL LABOR AND MATERIALS **$ 2,911,567.28**

5.0 Installed Equipment Costs for Boiler House #2 Spray Dry Absorber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
4. Lime cost based on material balance assuming 90% typical lime purity. NSR Ca:SO2 of 1.2 used for calculation.
5. Cost based on $38/ton disposal cost. Calculation assumes particulate from combustin of the COG and NG is negligible.
6. Within the utility industry, the SDA is labor intensitve. For a typical 200-500 MW application there are 16-20 operators required. This will be a slightly smaller operation that typical utility, and for purposes of this estimate a total of 10 operators is used 5 per shift.

Table B12b. Direct and Indirect Installation Costs, HSM Furnaces - Spray Dryer Absorber

Cost Item	Factor	Factor	Cost
Direct Costs			
Purchased Equipment Costs			
Primary Equipment[1]			$ 24,907,540
Ancilliary Equipment			$ -
Allowance for Unforseen			$ 2,490,754
Instrumentation		0.04	$ 1,095,932
Sales Taxes		0.06	$ 1,643,898
Freight		0.05	$ 1,369,915
Purchased Equipment Cost, PEC			$ 31,508,038
Direct Installation Costs[2]			
Foundations and Supports		0.02	$ 630,161
Handling and Erection		0.700	$ 19,191,888
Electrical		0.009	$ 246,585
Piping		0.01	$ 273,983
Ductwork		0.05	$ 1,369,915
Painting		0.01	$ 136,991
Direct Installation Costs, DC			$ 21,849,522
Site Preparation			$ 20,000
Buildings			$ -
Total Direct Costs (PEC + DC)			$ 53,377,561
Indirect Costs (Installation)			
Engineering		0.15	$ 4,726,206
Construction an Field Expenses		0.1	$ 3,150,804
Contractor Fees		0.1	$ 3,150,804
Startup		0.01	$ 189,048
Performance Test		0.003	$ 94,524
Model Study		0.005	$ 157,540
Contingencies		0.1	$ 3,150,804
Total Indirect Costs, IC			$ 14,619,730
Total Installed Cost			***$ 67,977,290***

[1] Primary equipment includes spray dry absorber and pulse jet fabric filter baghouse. Auxillary equipment is included with primary equipment cost.

[2] Due to the high water table at this location, it is probable that piling foundations will be required for installation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required to determine the scope of the piling effort.

Table B12a. Annual Cost Factors, HSM Furnaces - Spray Dry Absorber

Cost Item	Factor	Cost
Direct Annual Costs, DC		
Operating Labor		
Operator	General Operating	$ 336,830
Supervisor	15% of Operator	$ 50,525
Material	0.5% of General Operation	$ 1,684
Maintenance		
Maintenance Employee	General Maintenance	$ 1,133,848
Supervisor	15% of Maintenance Labor	$ 200,091
Material	100% of Maintenance Labor	$ 1,333,939
Utilities		
Electricity		$ 953,604
Water		$ 5,042
Reagents	Lime	$ 586,288
Solids Disposal	Gypsum solids from FFBH	$ 369,420
Indirect Annual Costs, IC		
Administrative Charges	2% of Total Capital Investment	$ 1,359,546
Property Tax	1% of Total Capital Investment	$ 679,773
Insurance	1% of Total Capital Investment	$ 679,773
Overhead	60% of total Labor and Materials	$ 2,978,726
Capital Recovery[1]	0.1098 x Total Capital Investment	$ 7,463,906
Total Annual Cost		$ 18,132,994
	2010 Uncontrolled SO_2 Actual Emissions (tpy)	*2240.0*
	Allowance for Uncontrolled Maint Outages (tpy) - 15 days	*111.7*
	SO_2 Removal Efficiency	*80%*
	Post-Control Emission Factor (lb/MMBtu)	*0.046*
	Control Cost Per Ton SO_2	**$ 10,650**

[1] Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for HSM Furnaces Spray Dry Absorber

Summary of Equipment Included in Estimate KJ 2-12-14

1 This option involves the addition of a new Spray Dry Absorber system and associated baghouse to collect residual carryover. The existing stacks will be tied into a new duct system to the SDA, the baghouse, and a new stack. Due to plot plan limitations this will need to a 450 ft flue gas handling system duct run from the boiler house to the stack. The duct will be elevated 30 ft above grade. Prior to entering the SDA the flue gas will be partially quenched to 300 ^{o}F. The primary SDA components include: Lime/reagent feed system, SO_2 removal system, spray dryers, ID fans, and waste/byproduct handling system. A new GEP chimney is also included. The key fabric filter components include: fabric filter enclosure, bags, and ash handling system.

4 Installed Equipment Costs for HSM Furnaces Spray Dry Absorber

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	New Stack	1	-	-	International Chimney	1	$ 833,333	$833,333	2014	1	1	1	$ 833,333
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	2	$ 104,576	$209,152	2014	1	1	1	$ 209,152
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	2	$ 472,844	$945,688	2014	1	1	1	$ 945,688
4	New Fans	4	CS	CS	Included with SDA	1	$ -	$0	2014	1	1	1	$ -
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	$ 658	$361,900	2011	593	600	1	$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	$ 108,570	$108,570	2011	593	600	1	$ 109,852
7	Spray Dry Injection System	7	-	-	CUECOST	1	$ 16,550,960	$16,550,960	2014	1	1	1	$ 16,550,960
8	New FFBH for SDA system	8	-	-	CUECOST	1	$ 5,821,883	$5,821,883	2014	1	1	1	$ 5,821,883
9	Partial Quench System (to 300 F)	9	CS	CS	CB&I Estimate	1	$ 70,500	$70,500	2014	1	1	1	$ 70,500
10													
11													
													$ 24,907,540

Notes:

1 Estimate for self supporting column (concrete with block lining), 16' 10" diameter, including aircraft lights, ladder and testing platforms. Pricing from International Chimney Corporation, ICC File CC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECost3, EPA cost model, 2014 basis. Estimate based on duct flow of 658,721 acfm at 147 Deg. F entering the IDF.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Cost for SDA system based on CUECost3 EPA cost model, 2014 basis. The SDA was estimated based on an inlet flow of 824,758 acfm. The gas leaving the SDA will approach saturation temperature .
The basis the outlet gas is an adiabatic saturation temperature of 127 Deg. F, with a 20 degree approach, for a SDA outlet temperature of 147 Deg. F. A 5 Deg. F reheat at the fan is added.
Control costs are based on a SO2 loading of 2713 ton per year to the SDA.

8 New pulse jet fabric filter baghouse based on CUECOST 3, EPA cost model, 2014 basis. The FFBH was estimated based on a flow of 658,721 acfm at 147 Deg. F. The cost is based on Pulse Jet type, and Gas-to-Cloth Ratio of 4.
An ash rate of 5,000 lb/hr was used for ash handling equipment sizing, as this is a minimal value for a basic ash handling system..

9 Partial quench system @ 200 gpm (pumps, piping, valves, lances/nozzles, I&C)

5.0 Installed Equipment Costs for HSM Furnaces Spray Dry Absorber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity

Fan Electricity

Flow	658721	ACFM	
Pressure Drop	15	iwc	(3 inches duct, 5 inches SDA, 6 inches FFBH, 1 inch stack)
Fan Efficiency	0.8	fraction	
Gas S.G. (Air = 1)	1		Use 1
Belt Efficiency	1		Typical Efficiencies
Motor Efficiency	0.95		Motor *1kW - 0.4*
Power (BHP)	1943	BHP	Motor *10 kW - 0.87*
Motor Efficiency	95	%	
Power (KW)	1525.3	KW	Motor *100 kW - 0.92*
Electricity Cost ($/KW-hr)	$ 0.06		Belt *1 kW - 0.78*
Hours Operated/Yr	8760	hr	Belt *10 kW - 0.88*
Annual Electricity Cost ($)	$ 801,705		Belt *100 kW - 0.93*

Electricity Other Uses

From CUECOST3	289	KW	Costing from CUECOST model.
Electricity Cost ($/KW-hr)	$ 0.06		
Hours Operated/Yr	8760	hr	
Annual Electricity Cost ($)	$ 151,898.40		
Total Electricity Cost ($)	**$ 953,603.54**		

2.0 Water Costs

SDA System

Estimated Water Use (gpm)	400	gpm	Water primarily evaporated in SDA
Hours Per Year	8760		
Annual Gallons	25,208,633	gal/yr	
Water Cost ($/kgal)	$ 0.20		
Annual Water Cost	**$ 5,041.73**		

2.0 Operating Labor Cost

		Labor Cost		Labor (hr/yr)	Comment
Quench System	$ 18,980	26	$/hr	730	1 hr/shift x 2 shifts x 365 day/yr
SDA System	$ 270,400	26	$/hr	10400	Note 6
Stack	$ 9,490	26	$/hr	365	1 hr/day x 365 day/yr
Baghouse	$ 37,960	26	$/hr	1460	Inspect 2/shift x 2 * 365
Misc.	$ -				
Supervision	$ 50,525	Note 1			
Annual Total Operating Labor	**$ 387,355**				

3.0 Maintenance

Total Installed Direct Cost	$ 53,357,561	
Total Maintenance Materials	$ 1,333,939	Note 2
Total Maintenance Labor	$ 1,333,939	Note 2
Total Annual Maintenance Cost	**$ 2,667,878**	

Calculate Temperature Profile Through APC System

	Flow	Temperature	
Absorber Inlet	824,758	300	
Absorber Outlet	658,721	147	SDA quenching effect
FFBH Outlet	658,721	147	
Fan Outlet	664,147	152	ID Fan Reheat = 5 Deg F

Note: Flow prior to quench is 933,279 acfm at 550 Deg. F

4.0 Reagents

Reagent Purity	90		
SO2 to Absorber	2713	tons/yr	
Operating Hours	8760	hr	
Lime Requirement (100% basis)	2852	tons/yr	
Actual Lime Requirement	3169	tons/yr	
Lime Unit Cost	185	$/ton	
Annual Lime Cost	**$ 586,288**	$/year	Note 4

5.0 Disposal

CaO + SO2 + 1/2 O2 + 2H20 --> CaSO4*2H20

Annual Lime Use	2,852	ton/yr	Note 5
Impurity	317	ton/yr	
Waste gypsum + Inerts	9722	tons	
Cost Disposal	38	$/ton	
Annual Disposal Cost	**369,420**	$/yr	

TOTAL LABOR AND MATERIALS **$ 4,964,544.02**

5.0 Installed Equipment Costs for HSM Furnaces Spray Dry Absorber

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
4. Lime cost based on material balance assuming 90% typical lime purity. NSR Ca:SO2 of 1.2 used for calculation.
5. Cost based on $38/ton disposal cost. Calculation assumes particulate from combustin of the COG and NG is negligible.
6. Within the utility industry, the SDA is labor intensitve. For a typical 200-500 MW application there are 16-20 operators required. This will be a slightly smaller operation that typical utility, and for purposes of this estimate a total of 10 operators is used 5 per shift.

Table B13b. Direct and Indirect Installation Costs, Boiler House #1 - Dry Sorbent Injection

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment[1]		$ 8,144,619
Ancilliary Equipment		$ -
Allowance for Unforseen		$ 814,462
Instrumentation	0.04	$ 358,363.23
Sales Taxes	0.06	$ 537,544.84
Freight	0.05	$ 447,954
Purchased Equipment Cost, PEC		$ 10,302,943
Direct Installation Costs		
Foundations and Supports[2]	0.1	$ 895,908
Handling and Erection	0.66	$ 5,902,510
Electrical	0.015	$ 134,386
Piping	0.03	$ 268,772
Ductwork	0.09	$ 806,317
Painting	0.01	$ 45,691
Direct Installation Costs, DC		$ 8,053,585
Site Preparation		$ 20,000
Buildings		$ -
Total Direct Costs (PEC +DC)		$ 18,376,528
Indirect Costs (Installation)		
Engineering	0.15	$ 1,545,441
Construction an Field Expenses	0.1	$ 1,030,294
Contractor Fees	0.1	$ 1,030,294
Startup	0.007	$ 72,121
Performance Test	0.005	$ 51,515
Model Study	0	$ -
Contingencies	0.1	$ 1,030,294
Total Indirect Costs, IC		$ 4,759,960
Total Installed Cost		**$ 23,136,488**

[1] Primary equipment includes dry sorbent injection system, and pulse jet baghouse. Ancillary equipment includes: partial quench system, ID fans, and new stack/chimney.

2 Due to the high water table at this location, it is probable that piling foundations will be required for instllation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required.

Table B13a. Annual Cost Factors, Boiler House #1 - Dry Sorbent Injection

Cost Item	Factor		Cost
Direct Annual Costs, DC			
Operating Labor			
Operator	General Operating	$	120,510
Supervisor	15% of Operator	$	18,077
Material	5% of Operation	$	6,929
Maintenance			
Maintenance Employee	General Maintenance	$	171,139
Supervisor	15% of Maintenance Labor	$	30,201
Material	100% of Maintenance Labor	$	201,340
Utilities			
Electricity		$	414,195
Water		$	24,528
Reagents	Trona	$	68,083
Ash Disposal		$	11,777
Indirect Annual Costs, IC			
Administrative Charges	2% of Total Capital Investment	$	462,730
Property Tax	1% of Total Capital Investment	$	231,365
Insurance	1% of Total Capital Investment	$	231,365
Overhead	60% of total Labor and Materials	$	635,910
Capital Recovery[1]	0.1098 x Total Capital Investment	$	2,540,386
Total Annual Cost		$	5,168,534
	2010 Uncontrolled SO_2 Actual Emissions (tpy)		*407.35*
	Allowance for Uncontrolled Maint. Outages (tpy) - 15 days		*19.3*
	SO_2 Removal Efficiency		*50%*
	Post-Control SO_2 Emission Factor (lb/MMBtu)		*0.057*
	Control Cost Per Ton SO_2	***$***	***26,640***

[1] Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #1 Dry Sorbent Injection

Notes

KJ 2-12-14

1 This option involves the addition of a new dry sorbent injection system and associated baghouse. The existing stacks will be tied together into a new duct system to a new stack. Due to plot plan limitations this will need to a 450 ft run from the boiler house to the stack. The rack will be elevated 30 ft above grade. A partial quench system will be added to the system to reduce the duct temperature to around 300 Deg. F. Key components of the DSI system will include storage and feeding systems. Key components of the pulse jet fabric filter will include the baghouse structure, bags/cages, and ash handling system. The system will also include new fans and stack/chimney.

4.0 Installed Equipment Costs for Boiler House #1 Dry Sorbent Injection

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	New Chimney/stack	1	-	-	International Chimney	1	$ 666,667	$666,667	2014	1	1	1	$ 666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	$ 104,576	$104,576	2014	1	1	1	$ 104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	$ 472,844	$472,844	2014	1	1	1	$ 472,844
4	New Fans	4	CS	CS	Included with baghouse	1	$ -	$0	2014	1	1	1	$ -
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	$ 658	$361,900	2011	593	600	1	$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	$ 109,852	$109,852	2011	593	600	1	$ 111,148
7	Dry Sorbent Injection System	7	-	-	IPM Cost Model	1	$ 2,678,702	$2,678,702	2014	1	1	1	$ 2,678,702
8	New Baghouse for DIS system	8	-	-	CUECOST3	1	$ 3,674,010	$3,674,010	2014	1	1	1	$ 3,674,010
9	Partial Quench System	9	CS	CS	CB&I Estimate	1	$ 70,500	$70,500	2014	1	1	1	$ 70,500
10													
11													
													$ 8,144,619

Notes:

1 Estimate for self supporting stack, 11'7" ID, including aircraft warning lights, ladder, and tesitng platform. Pricing for 213 ft stack from International Chimney Corporation, ICC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECOST3, EPA cost model, 2014 basis. Estimate based on duct flow of 330,130 acfm acfm at 300 Deg. F.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Cost based on EPA Cost Model, IPM Model, Project 12301-007, August 20, 2010. Cost estimate is based on Trona feed rate. PTE of 470.2 tons of SO2 per year was factored based on a total heat input of 250 MMBtu/hr. Calculated SO2 emission factor of 107.36 lb/hr/250MMBtu/hr = 0.429 lb/MMBtu. Estimate from model is total direct installation cost, and includes DSI equipment, installation, foundations, controls, electrical, and retrofit difficulty.

8 New baghouse based on CUECOST 3, EPA cost model, 2014 basis. The baghouse was estimated based on a flow of 330130 acfm at 300 Deg. F. The cost is based on Pulse Jet type, and Gas-to-Cloth Ratio of 6. A nominal ash rate of 5,000 lb/hr was used for ash equipment sizing.

9 Partial quench system @ 200 gpm (pumps, valves, lances/nozzles, duct corrosion lining).

5.0 Installed Equipment Costs for Boiler House #1 Dry Sorbent Injection

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity

Fan Electricity

Flow	330130	ACFM	
Pressure Drop	12	iwc	(3 inches duct, 2 inches DSI, 6 inches FFBH, 1 inch stack)
Fan Efficiency	0.8	fraction	
Gas S.G. (Air = 1)	1		Use 1
Belt Efficiency	1		Typical Efficiencies
Motor Efficiency	0.95		Motor *1kW - 0.4*
Power (BHP)	779	BHP	Motor *10 kW - 0.87*
Motor Efficiency	95	%	
Power (KW)	611.6	KW	Motor *100 kW - 0.92*
Electricity Cost ($/KW-hr)	$ 0.06		Belt *1 kW - 0.78*
Hours Operated/Yr	8760	hr	Belt *10 kW - 0.88*
Annual Electricity Cost ($)	$ 321,431		Belt *100 kW - 0.93*

	acfm	Deg. F
Boiler Flow	438,726	550
Post Quench	330,130	300
Post DSI	330,130	300
Post FFBH	330,130	300
IDF Outlet	332,302	305

Pumping

Pumping Rate	200	gpm
TDH	200	ft
Pump Efficiency	75%	
Motor Efficiency	92%	
Annual Hours of Operation	8760	hr/yr
Electricity Cost ($/KW-hr)	0.06	$/Kw-hr
Brake Horsepower	7.59	BHP
Annual Electricity Cost	$ 3,233.48	($/year)

Electricity Other Uses

Other	170.34	KW	Costing from CEUCOST model - FFBH + DSI
Electricity Cost ($/KW-hr)	$ 0.06		
Hours Operated/Yr	8760	hr	
Annual Electricity Cost ($)	$ 89,530.70		

Total Electricity Cost ($)	**$ 414,195.46**

2.0 Water Costs

Partial Quench

Estimated Partial Quench (gpm)	200	Quench associated with lowering temperature of flue gas
Hours Per Year	8760	
Water Cost ($/kgal)	$ 2.00	
Annual Water Cost	$ 3,504.00	

Annual Water Cost	**$ 24,528.00**

3.0 Operating Labor Cost

Quench System	$ 18,980.00	26	$/hr	730	1 hr/shift x 2 shifts x 365 day/yr
DSI System	$ 54,080.00	26	$/hr	4160	1 operator x 2 shifts x 365 days/yr
Stack	$ 9,490.00	26	$/hr	365	1 hr/day x 365 day/yr
Baghouse	$ 37,960.00	26	$/hr	1460	Inspect 2/shift x 2 * 365
Misc.	$ -				
Supervision	$ 18,076.50	Note 1			
Annual Total Operating Labor	**$ 138,586.50**				

4.0 Maintenance

Total Installed Direct Cost	$ 8,053,585	
Total Maintenance Materials	$ 201,340	Note 2
Total Maintenance Labor	$ 201,340	Note 2
Total Annual Maintenance Cost	**$ 402,679**	Note 3

5.0 Reagents

Trona Reagent	**68,083**	Note 4

5.0 Installed Equipment Costs for Boiler House #1 Dry Sorbent Injection

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

6.0 Disposal

Trona Disposal	**$ 11,777**	Note 5
TOTAL LABOR AND MATERIALS	**$ 1,059,849.23**	

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on a basis of 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
4. Trona cost based on EPA Cost Model, IPM Model, August 20, 2010 .
   Basis for Trona is milled trona at a NSR of 0.848. Model based on 50% SO_2 removal.
5. Cost based on $38/ton disposal cost.

Table B14b. Direct and Indirect Installation Costs, Boiler House #2 - Dry Sorbent Injection

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment[1]		$ 8,508,675
Ancilliary Equipment		$ -
Allowance for Unforseen		$ 850,868
Instrumentation	0.04	$ 374,381.70
Sales Taxes	0.06	$ 561,572.56
Freight	0.05	$ 467,977
Purchased Equipment Cost, PEC		$ 10,763,474
Direct Installation Costs		
Foundations and Supports[2]	0.1	$ 935,954
Handling and Erection	0.66	$ 6,192,890
Electrical	0.015	$ 140,393
Piping	0.03	$ 280,786
Insulation for Ductwork	0.09	$ 842,359
Painting	0.01	$ 47,734
Direct Installation Costs, DC		$ 8,440,116
Site Preparation		$ 20,000
Buildings		$ -
Total Direct Costs (PEC +DC)		$ 19,223,590
Indirect Costs (Installation)		
Engineering	0.15	$ 1,614,521
Construction an Field Expenses	0.1	$ 1,076,347
Contractor Fees	0.1	$ 1,076,347
Startup	0.006	$ 64,581
Performance Test	0.005	$ 53,817
Model Study	0	$ -
Contingencies	0.1	$ 1,076,347
Total Indirect Costs, IC		$ 4,961,962
Total Installed Cost		**$ 24,165,552**

1 Primary equipment includes dry sorbent injection system, and pulse jet baghouse. Ancillary equipment includes: partial quench system, ID fans, and new stack/chimney.

2 Due to the high water table at this location, it is probable that piling foundations will be required for instllation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required.

Table B14a. Annual Cost Factors, Boiler House #2 - Dry Sorbent Injection

Cost Item	Factor	Cost
Direct Annual Costs, DC		
Operating Labor		
Operator	General Operating	$ 120,510
Supervisor	15% of Operator	$ 18,077
Material	5% of Operation	$ 6,929
Maintenance		
Maintenance Employee	General Maintenance	$ 179,352
Supervisor	15% of Maintenance Labor	$ 31,650
Material	100% of Maintenance Labor	$ 211,003
Utilities		
Electricity		$ 503,434
Water		$ 24,528
Reagents	Trona	$ 53,984
Solids Disposal		$ 9,338
Indirect Annual Costs, IC		
Administrative Charges	2% of Total Capital Investment	$ 483,311
Property Tax	1% of Total Capital Investment	$ 241,656
Insurance	1% of Total Capital Investment	$ 241,656
Overhead	60% of total Labor and Materials	$ 691,126
Capital Recovery	0.1098 x Total Capital Investment	$ 2,653,378
Total Annual Cost		$ 5,469,930
	2010 Uncontrolled SO_2 Actual Emissions (tpy)	*750*
	Allowance for Uncontrolled Maint. Outages (tpy) - 15 days	*15.3*
	SO_2 Removal Efficiency	*50%*
	Post-Control SO_2 Emission Factor (lb/MMBtu)	*0.087*
	Control Cost Per Ton SO_2	***$ 14,890***

[1] Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #2 Dry Sorbent Injection

Notes

KJ 2-12-14

1 This option involves the addition of a new dry sorbent injection system and associated baghouse. The existing stacks will be tied together into a new duct system to a new stack. Due to plot plan limitations this will need to a 450 ft run from the boiler house to the stack. The rack will be elevated 30 ft above grade. A partial quench system will be added to the system to reduce the duct temperature to around 300 Deg. F. Key components of the DSI system will include storage and feeding systems. Key components of the pulse jet fabric filter will include the baghouse structure, bags/cages, and ash handling system. The system will also include new fans and stack/chimney.

4 Installed Equipment Costs for Boiler House #2 Dry Sorbent Injection

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	New Chimney/stack	1	-	-	International Chimney Corp.	1	$ 666,667	$666,667	2014	1	1	1	$ 666,667
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	1	$ 104,576	$104,576	2014	1	1	1	$ 104,576
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	1	$ 472,844	$472,844	2014	1	1	1	$ 472,844
4	New Fans	4	CS	CS	Included with baghouse	1	$ -	$0	2014	1	1	1	$ -
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	$ 658	$361,900	2011	593	600	1	$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	$ 109,852	$109,852	2011	593	600	1	$ 111,148
7	Dry Sorbent Injection System	7	-	-	IPM Cost Model	1	$ 2,508,522	$2,508,522	2014	1	1	1	$ 2,508,522
8	New Baghouse for DSI system	8	-	-	CUECOST3	1	$ 4,208,246	$4,208,246	2014	1	1	1	$ 4,208,246
9	Partial Quench System	9	CS	CS	CB&I Estimate	1	$ 70,500	$70,500	2014	1	1	1	$ 70,500
10													
11													
													$ 8,508,675

Notes:

1 New stack calculated from CUECOST3, EPA cost model, 2014 basis. Stack sizing based on 409,029 acfm at 305 Deg. F

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECOST3, EPA cost model, 2014 basis. Estimate based on duct flow of 406,355 acfm at 300 Deg. F.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Cost based on EPA Cost Model, IPM Model, Project 12301-007, August 20, 2010. Cost estimate is based on Trona feed rate. PTE of 373 tons of SO2 per year was factored based on a total heat input of 1000 MMBtu/hr. Calculated SO2 emission factor of 85.15 lb/hr/1000MMBtu/hr = 0.0815 lb/MMBtu. Estimate from model is total direct installation cost, and includes DSI equipment, installation, foundations, controls, electrical, and retrofit difficulty.

8 New baghouse based on CUECOST 3, EPA cost model, 2014 basis. The baghouse was estimated based on a flow of 406355 acfm at 300 Deg. F. The cost is based on Pulse Jet type, and Gas-to-Cloth Ratio of 6. A nominal ash rate of 5,000 lb/hr was used for ash equipment sizing.

9 Partial quench system @ 200 gpm (pumps, valves, lances/nozzles, duct corrosion lining).

5.0 Installed Equipment Costs for Boiler House #2 Dry Sorbent Injection

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity

Fan Electricity

Flow	406355	ACFM				
Pressure Drop	12	iwc	(3 inches duct, 2 inches DSI, 6 inches FFBH, 1 inch stack)			
Fan Efficiency	0.8	fraction				
Gas S.G. (Air = 1)	1		Use 1		acfm	Deg. F
Belt Efficiency	1		Typical Efficiencies	Boiler Flow	540,025	550
Motor Efficiency	0.95		Motor *1kW - 0.4*	Post Quench	406,355	300
Power (BHP)	959	BHP	Motor *10 kW - 0.87*	Post DSI	406,355	300
Motor Efficiency	95	%		Post FFBH	406,355	300
Power (KW)	752.8	KW	Motor *100 kW - 0.92*	IDF Outlet	409,029	305
Electricity Cost ($/KW-hr)	$ 0.06		Belt *1 kW - 0.78*			
Hours Operated/Yr	8760	hr	Belt *10 kW - 0.88*			
Annual Electricity Cost ($)	$ 395,648		Belt *100 kW - 0.93*			

Pumping

Pumping Rate	200	gpm
TDH	200	ft
Pump Efficiency	75%	
Motor Efficiency	92%	
Annual Hours of Operation	8760	hr/yr
Electricity Cost ($/KW-hr)	0.06	$/Kw-hr
Brake Horsepower	7.59	BHP
Annual Electricity Cost	$ 3,233.48	($/year)

Electricity Other Uses

Other	198.92	KW	Costing from CEUCOST model - FFBH +DSI.
Electricity Cost ($/KW-hr)	$ 0.06		
Hours Operated/Yr	8760	hr	
Annual Electricity Cost ($)	$ 104,552.35		
Total Electricity Cost ($)	**$ 503,433.63**		

2.0 Water Costs

Partial Quench

Estimated Partial Quench (gpm)	200	Quench associated with lowering temperature of flue gas
Hours Per Year	8760	
Water Cost ($/kgal)	$ 2.00	
Annual Water Cost	$ 3,504.00	
Annual Water Cost	**$ 24,528.00**	

3.0 Operating Labor Cost

Quench System	$ 18,980.00	26	$/hr	730	1 hr/shift x 2 shifts x 365 day/yr
DSI System	$ 54,080.00	26	$/hr	4160	1 operator x 2 shifts x 365 days/yr
Stack	$ 9,490.00	26	$/hr	365	1 hr/day x 365 day/yr
Baghouse	$ 37,960.00	26	$/hr	1460	Inspect 2/shift x 2 * 365
Misc.	$ -				
Supervision	$ 18,076.50	Note 1			
Annual Total Operating Labor	**$ 138,586.50**				

4.0 Maintenance

Total Installed Direct Cost	$ 8,440,116	
Total Maintenance Materials	$ 211,003	Note 2

5.0 Installed Equipment Costs for Boiler House #2 Dry Sorbent Injection

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

Total Maintenance Labor	$ 211,003	Note 2
Total Annual Maintenance Cost	**$ 422,006**	Note 3
5.0 Reagents		
Trona Reagent	**53,984**	Note 4
6.0 Disposal		
Trona Disposal	**$ 9,338**	Note 5
TOTAL LABOR AND MATERIALS	**$ 1,151,876**	

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on CUECOST basis of 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
4. Trona cost based on EPA Cost Model, IPM Model, August 20, 2010 .
   Basis for Trona is milled trona at a NSR of 0.848. Model based on 50% SO2 removal.
5. Cost based on $38/ton disposal cost.

Table B15b. Direct and Indirect Installation Costs, HSM Furnaces - Dry Sorbent Injection

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment[1]		$ 13,029,041
Ancilliary Equipment		$ -
Allowance for Unforseen		$ 1,302,904
Instrumentation	0.04	$ 573,277.82
Sales Taxes	0.06	$ 859,916.73
Freight	0.05	$ 716,597
Purchased Equipment Cost, PEC		$ 16,481,737
Direct Installation Costs		
Foundations and Supports[2]	0.06	$ 859,917
Handling and Erection	0.69	$ 9,834,414
Electrical	0.01	$ 143,319
Piping	0.02	$ 214,979
Ductwork	0.10	$ 1,361,535
Painting	0.01	$ 73,093
Direct Installation Costs, DC		$ 12,487,257
Site Preparation		$ 20,000
Buildings		$ -
Total Direct Costs (PEC +DC)		$ 28,988,994
Indirect Costs (Installation)		
Engineering	0.15	$ 2,472,261
Construction an Field Expenses	0.1	$ 1,648,174
Contractor Fees	0.1	$ 1,648,174
Startup	0.006	$ 98,890
Performance Test	0.005	$ 82,409
Model Study	0	$ -
Contingencies	0.1	$ 1,648,174
Total Indirect Costs, IC		$ 7,598,081
Total Installed Cost		**$ 36,587,075**

1 Primary equipment includes dry sorbent injection system, and pulse jet baghouse. Ancillary equipment includes: partial quench system, ID fans, and new stack/chimney.

2 Due to the high water table at this location, it is probable that piling foundations will be required for instllation of structural equipment. Such costs have not been included in the estimate as additional geotechnical evaluation will be required.

Table B15a. Annual Cost Factors, HSM Furnaces - Dry Sorbent Injection

Cost Item	Factor	Cost	
Direct Annual Costs, DC			
Operating Labor			
Operator	General Operating	$	120,510
Supervisor	15% of Operator	$	18,077
Material	5% of Operation	$	6,929
Maintenance			
Maintenance Employee	General Maintenance	$	265,354
Supervisor	15% of Maintenance Labor	$	46,827
Material	100% of Maintenance Labor	$	312,181
Utilities			
Electricity		$	958,465
Water		$	42,048
Reagents	Trona	$	394,334
Solids Disposal		$	68,209
Indirect Annual Costs, IC			
Administrative Charges	2% of Total Capital Investment	$	731,742
Property Tax	1% of Total Capital Investment	$	365,871
Insurance	1% of Total Capital Investment	$	365,871
Overhead	60% of total Labor and Materials	$	1,335,603
Capital Recovery[1]	0.1098 x Total Capital Investment	$	4,017,261
Total Annual Cost		$	9,049,282
	2010 Uncontrolled SO_2 Actual Emissions (tpy)		*2240*
	Allowance for Uncontrolled Maint. Outages (tpy) - 15 days		*111.7*
	SO_2 Removal Efficiency		*50%*
	Post-Control SO_2 Emission Factor (lb/MMBtu)		*0.101*
	Control Cost Per Ton SO_2	***$***	***8,081***

[1] Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for HSM Furnaces Dry Sorbent Injection

Notes

KJ 2-12-14

1 This option involves the addition of a new dry sorbent injection system and associated baghouse. The existing stacks will be tied together into a new duct system to a new stack. Due to plot plan limitations this will need to a 450 ft run from the boiler house to the stack. The rack will be elevated 30 ft above grade. A partial quench system will be added to the system to reduce the duct temperature to around 300 Deg. F. Key components of the DSI system will include storage and feeding systems. Key components of the pulse jet fabric filter will include the baghouse structure, bags/cages, and ash handling system. The system will also include new fans and stack/chimney.

4 Installed Equipment Costs for HSM Furnaces Dry Sorbent Injection

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	New Chimney/stack	1	-	-	International Chimney Corp.	1	$ 833,333	$833,333	2014	1	1	1	$ 833,333
2	New Duct Structural Supports (30 ft elev.)	2	CS	CS	CB&I Estimate	2	$ 104,576	$209,152	2014	1	1	1	$ 209,152
3	New Ductwork 450' x 15' x 20' to Stack	3	MS	MS	CB&I Estimate	2	$ 472,844	$945,688	2014	1	1	1	$ 945,688
4	New Fans	4	CS	CS	Included with baghouse	1	$ -	$0	2014	1	1	1	$ -
5	Tie Stacks into New Structural Ductwork	5	SS	SS	Quote, Shaw E&I, Atlanta, LF	550	$ 658	$361,900	2011	593	600	1	$ 366,172
6	Allowance for Duct Bends and Dampers (30%)	6	-	-	Allowance, Lot	1	$ 109,852	$109,852	2011	593	600	1	$ 111,148
7	Dry Sorbent Injection System	7	-	-	IPM Cost Model	1	$ 4,410,255	$4,410,255	2014	1	1	1	$ 4,410,255
8	New Baghouse for DIS system	8	-	-	CUECOST3	1	$ 6,082,793	$6,082,793	2014	1	1	1	$ 6,082,793
9	Partial Quench System	9	CS	CS	CB&I Estimate	1	$ 70,500	$70,500	2014	1	1	1	$ 70,500
10													
11													
													$ 13,029,041

Notes:

1 Estimate for self supporting column (concrete with block lining), 16'10" ID, including aircraft lights, ladder and testing platforms. Pricing from International Chimney Corporation, ICC File CC-42408-C.

2 New structural supports will support new structural process ductwork. Based on use of three main support structures 15 ft x 20 ft, and 4 intermediate support braces.

3 New ductwork is based on structural process duct with dimensions 15 ft x 20 ft, and an estimated run of 450 feet.

4 New fan cost is included in the baghouse estimate calculated from CUECOST3, EPA cost model, 2014 basis. Estimate based on duct flow of 702,269 acfm at 300 Deg. F.

5 Quote from Shaw E&I, Atlanta, 2011 for stainless steel large diameter flanged duct, API 5L or 10 gauge.

6 Typical allowance, as specified in RLMeans for ancillary piping/duct materials.

7 Cost based on EPA Cost Model, IPM Model, Project 12301-007, August 20, 2010. Cost estimate is based on Trona feed rate. PTE of 2713 tons of SO2 per year was factored based on a total heat input of 2660 MMBtu/hr. Calculated SO2 emission factor of 620.6 lb/hr/2660 MMBtu/hr = 0.2333 lb/MMBtu. Estimate from model is total direct installation cost, and includes DSI equipment, installation, foundations, controls, electrical, and retrofit difficulty.

8 New baghouse based on CUECOST 3, EPA cost model, 2014 basis. The baghouse was estimated based on a flow of 702269 acfm at 300 Deg. F. The cost is based on Pulse Jet type, and Gas-to-Cloth Ratio of 6. A nominal ash rate of 5,000 lb/hr was used for ash equipment sizing.

9 Partial quench system @ 200 gpm (pumps, valves, lances/nozzles, duct corrosion lining).

5.0 Installed Equipment Costs for HSM Furnaces Dry Sorbent Injection

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

1. Electricity

Fan Electricity

Flow	702,269	ACFM	
Pressure Drop	12	iwc	(3 inches duct, 2 inches DSI, 6 inches FFBH, 1 inch stack)
Fan Efficiency	0.8	fraction	
Gas S.G. (Air = 1)	1		Air = .075 lb/ft3 @ 70 Deg. F
Belt Efficiency	1		Typical Efficiencies
Motor Efficiency	0.95		Motor *1kW - 0.4*
Power (BHP)	1657	BHP	Motor *10 kW - 0.87*
Motor Efficiency	95	%	
Power (KW)	1300.9	KW	Motor *100 kW - 0.92*
Electricity Cost ($/KW-hr)	$ 0.06		Belt *1 kW - 0.78*
Hours Operated/Yr	8760	hr	Belt *10 kW - 0.88*
Annual Electricity Cost ($)	$ 683,765		Belt *100 kW - 0.93*

	acfm	Deg. F
HSM Furnace Flow	933,279	550
Post Quench	702,269	300
Post DSI	702,269	300
Post FFBH	702,269	300
IDF Outlet	706,890	305

Pumping

Pumping Rate	200	gpm
TDH	200	ft
Pump Efficiency	75%	
Motor Efficiency	92%	
Annual Hours of Operation	8760	hr/yr
Electricity Cost ($/KW-hr)	0.06	$/Kw-hr
Brake Horsepower	7.59	BHP
Annual Electricity Cost	$ 3,233.48	($/year)

Electricity Other Uses

Other	516.49	KW	Costing from CUECOST model - FFBH + DSI.
Electricity Cost ($/KW-hr)	$ 0.06		
Hours Operated/Yr	8760	hr	
Annual Electricity Cost ($)	$ 271,467.14		

Total Electricity Cost ($)	**$ 958,465.28**

2.0 Water Costs

Partial Quench

Estimated Partial Quench (gpm)	400	Quench associated with lowering temperature of flue gas
Hours Per Year	8760	
Water Cost ($/kgal)	$ 0.20	
Annual Water Cost	$ 42,048	

Other

Estimated (gpm)	0	Miscellaneous use.
Hours Per Year	8760	
Water Cost ($/kgal)	$ 0.20	
Annual Water Cost	$ -	

Annual Water Cost	**$ 42,048.00**

3.0 Operating Labor Cost

Quench System	$ 18,980.00	26 $/hr	730	1 hr/shift x 2 shifts x 365 day/yr
DSI System	$ 54,080.00	26 $/hr	8320	2 operator x 2 shifts x 365 days/yr
Stack	$ 9,490.00	26 $/hr	365	1 hr/day x 365 day/yr
Baghouse	$ 37,960.00	26 $/hr	1460	Inspect 2/shift x 2 * 365
Misc.	$ -			
Supervision	$ 18,076.50	Note 1		
Annual Total Operating Labor	**$ 138,586.50**			

5.0 Installed Equipment Costs for HSM Furnaces Dry Sorbent Injection

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

4.0 Maintenance		
Total Installed Direct Cost	$ 12,487,257	
Total Maintenance Materials	$ 312,181	Note 2
Total Maintenance Labor	$ 312,181	Note 2
Total Annual Maintenance Cost	**$ 624,363**	Note 3
5.0 Reagents		
Trona Reagent	**394,334**	Note 4
6.0 Disposal		
Trona Disposal	**$ 68,209**	Note 5
TOTAL LABOR AND MATERIALS	**$ 2,226,006**	

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on CUECOST basis of 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
4. Trona cost based on EPA Cost Model, IPM Model, August 20, 2010 . Basis for Trona is milled trona at a NSR of 0.848. Model based on 50% SO2 removal.
5. Cost based on $38/ton disposal cost.

Table B16b. Direct and Indirect Installation Costs, Boiler House #1 - Fuel Switching

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment[1]		$ 6,030,927
Ancilliary Equipment		$ -
Allowance for Unforseen		$ 603,093
Instrumentation	0.04	$ 265,361
Sales Taxes	0.06	$ 398,041
Freight	0.05	$ 331,701
Purchased Equipment Cost, PEC		$ 7,629,123
Direct Installation Costs		
Foundations and Supports	0.05	$ 331,701
Handling and Erection	0.69	$ 4,554,641
Electrical	0.05	$ 331,701
Piping	0.08	$ 530,722
Ductwork	0.02	$ 119,412
Painting	0.01	$ 33,834
Direct Installation Costs, DC		$ 5,902,010
Site Preparation		$ 20,000
Buildings		$ -
Total Direct Costs (PEC +DC)		$ 13,551,133
Indirect Costs (Installation)		
Engineering	0.15	$ 1,144,368
Construction an Field Expenses	0.1	$ 762,912
Contractor Fees	0.1	$ 762,912
Startup	0.006	$ 45,775
Performance Test	0.007	$ 53,404
Model Study	0	$ -
Contingencies	0.1	$ 762,912
Two-Week Lost Production at the Blast Furnace		$ 8,031,000
Total Indirect Costs, IC		$ 11,563,284
Total Installed Cost		**$ 25,114,417**

[1] Primary equipment includes : replacement low NOx burner systems. Also included is replacement natural gas fuel supply system.

Table B16a. Annual Cost Factors, Boiler House #1 - Fuel Switching

Cost Item	Factor	Cost	
Direct Annual Costs, DC			
Operating Labor			
Operator	General Operating	$	18,980
Supervisor	15% of Operator	$	2,847
Material	5% of Total Operating	$	1,091
Maintenance			
Maintenance Employee	General Maintenance	$	125,418
Supervisor	15% of Maintenance Labor	$	22,133
Material	100% of Maintenance Labor	$	147,550
Utilities			
Annual Fuel Switching Costs		$	1,844,586
Indirect Annual Costs, IC			
Administrative Charges	2% of Total Capital Investment	$	502,288
Property Tax	1% of Total Capital Investment	$	251,144
Insurance	1% of Total Capital Investment	$	251,144
Overhead	60% of total Labor and Materials	$	1,295,200
Capital Recovery[1]	0.1098 x Total Capital Investment	$	2,757,563
Total Annual Cost		$	7,219,944
	2010 Uncontrolled SO_2 Actual Emissions (tpy)		*407.35*
	Allowance for Uncontrolled Maint. Outages (tpy) - 15 days		*0.0*
	SO_2 Removal Efficiency		*88.62%*
	Post-Control Emission Factor (lb/MMBtu)		*0.055*
	Control Cost Per Ton SO_2	***$***	***19,999***

[1] Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #1 Fuel Switching

Notes

KJ 2-12-14

1 This option involves replacment of existing burners in the boiler house. There are five boilers, each equipped with 4 natural gas burners. To burn 100% natural gas, these will need to be replaced with new low Nox burners. The natural gas burner upgrade will also necessitate the replacement of the natural gas supply piping to the burners to provide sufficient natural gas. This estimate is based on the natural gas utility providing gas supply to the property line, and USS installation of in-plant distribution piping.

4 Installed Equipment Costs for Boiler House #1 Fuel Switching

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	Burner System	1	CS	CS	North American Combustion , Inc.	20	$ 235,000	$4,700,000	2014	1	1	1	$ 4,700,000
2	Fuel Delivery System Replacement	2	CS	CS	CB&I Estimate	1	$ 1,330,927	$1,330,927	2014	1	1	1	$ 1,330,927
3													
4													
5													
6													
7													
8													
9													
10													
21													
													$ 6,030,927

Notes:

1 Burner system includes burner, fuel train/control valves, two (2) blowers, and control panel (I&C).

2 Fuel delivery replacement sized based on 1,000 MMBtu/hr capacity, assumes that utility will bring NG to site. Tie point will be Zug Island Rd on north side. Fuel piping will be routed along existing structural support systsems. Pricing based on Sch. 40 CS.

5.0 Installed Equipment Costs for Boiler House #1 Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

5.1 Baseline Cost of Fuel

Total Rating	1,684,852	MMBtu/yr				Baseline SO_2 Emissions		
Baseline NG	69,206	MMBtu/yr		Btu/scf	NG	0.0006	41	lb/yr
Baseline COG	503,315	MMBtu/yr	NG HHV	1012	COG	1.431	720,385	lb/yr
Baseline BFG	1,112,332	MMBtu/yr	BFG HHV	89	BFG	0.08279	92,087	lb/yr
Annual Hours Operation	8,760	hrs/yr	COG HHV	496		Total	812,513	lb/yr
Cost NG ($ per MMBtu)	$ 4.89	(Based on 2010 cost)					406	tpy
Cost COG ($ per MMBtu)	$ 2.92	(Based on 2010 Cost)						
Baseline Annual Cost	$ 1,808,096	(Cost NG and COG)						

5.2 Fuel Use After Fuel Switch

Total Rating	1,684,852	MMBtu/yr		Btu/scf		Post-Fuel Switch SO_2 Emissions		
Post-Fuel Switch NG	572,521	MMBtu/yr	NG HHV	1012	NG	0.0006	339	lb/yr
Post-Fuel Switch COG	-	MMBtu/yr	BFG HHV	89	COG	1.431	-	lb/yr
Post-Fuel Switch BFG	1,112,332	MMBtu/yr	COG HHV	496	BFG	0.082787	92,087	lb/yr
Annual Hours Operation	8,760	hrs/yr				Total	92,426	lb/yr
Cost NG ($ per MMBtu)	$ 6.38	(Based on average historical USS natural gas prices)					46	tpy
Future Projected Annual Cost	$ 3,652,682	(Cost NG and COG)						
				Post-Fuel Switch SO_2 Emission Reduction			360.0	tpy
					Post Control SO_2 Factor:		0.0549	lb/MMBtu

5.3 Baseline Fuel Cost - Fuel Swich Fuel Cost

$ 1,844,586

3.0 Operating Labor Cost

Burners	$ 18,980	26 $/hr	730	1 hr/shift x 2 shifts x 365 day/yr
Other	$ -	26 $/hr	0	-
Annual Total Operating Labor	**$ 18,980**			

4.0 Maintenance

Total Installed Direct Cost	$ 5,902,010	
Total Maintenance Materials	$ 147,550	Note 2
Total Maintenance Labor	$ 147,550	Note 2
Total Annual Maintenance Cost	**$ 295,101**	Note 3
TOTAL LABOR AND MATERIALS	**$ 2,158,666**	

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
4. Fuel SO_2 emission factors from 2013 Air Inventory.

5.0 Installed Equipment Costs for Boiler House #1 Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

Flow		Flow
5%	NG	
28%	COG	
67%	BFG	
100%		

Table B17b. Direct and Indirect Installation Costs, Boiler House #2 - Fuel Switching

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment[1]		$ 6,090,046
Ancilliary Equipment		$ -
Allowance for Unforseen		$ 609,005
Instrumentation	0.04	$ 267,962.04
Sales Taxes	0.06	$ 401,943
Freight	0.05	$ 334,953
Purchased Equipment Cost, PEC		$ 7,703,909
Direct Installation Costs		
Foundations and Supports	0.05	$ 334,953
Handling and Erection	0.68	$ 4,560,550
Electrical	0.05	$ 334,953
Piping	0.08	$ 535,924
Ductwork	0.02	$ 133,981
Painting	0.01	$ 34,165
Direct Installation Costs, DC		$ 5,934,526
Site Preparation		$ 20,000
Buildings		$ -
Total Direct Costs (PEC +DC)		$ 13,658,434
Indirect Costs (Installation)		
Engineering	0.15	$ 1,155,586
Construction an Field Expenses	0.1	$ 770,391
Contractor Fees	0.1	$ 770,391
Startup	0.006	$ 46,223
Performance Test	0.02	$ 154,078
Model Study	0	$ -
Contingencies	0.1	$ 770,391
Two-Week Lost Production at the Blast Furnace		$ 8,031,000
Total Indirect Costs, IC		$ 11,698,061
Total Installed Cost		**$ 25,356,495**

[1] Primary equipment includes : replacement low NOx burner systems. Also included is replacement natural gas fuel supply system.

Table B17a. Annual Cost Factors, Boiler House #2 - Fuel Switching

Cost Item		Factor	Cost
Direct Annual Costs, DC			
Operating Labor			
	Operator	General Operating	$ 18,980
	Supervisor	15% of Operator	$ 2,847
	Material	5% of Total Operating	$ 1,091
Maintenance			
	Maintenance Employee	General Maintenance	$ 126,109
	Supervisor	15% of Maintenance Labor	$ 22,254
	Material	100% of Maintenance Labor	$ 148,363
Utilities			
	Cost of Fuel Switch (Natural Gas for COG) 2010 Basis		$ 3,661,350
Indirect Annual Costs, IC			
Administrative Charges		2% of Total Capital Investment	$ 507,130
Property Tax		1% of Total Capital Investment	$ 253,565
Insurance		1% of Total Capital Investment	$ 253,565
Overhead		60% of total Labor and Materials	$ 2,386,234
Capital Recovery[1]		0.1098 x Total Capital Investment	$ 2,784,143
Total Annual Cost			$ 10,165,632
		2010 Uncontrolled SO_2 Actual Emissions (tpy)	*750*
		Allowance for Uncontrolled Maint. Outages (tpy) - 15 days	*0.0*
		SO_2 Removal Efficiency	*83.80%*
		Post-Control Emission Factor (lb/MMBtu)	*0.057*
		Control Cost Per Ton SO_2	***$ 16,168***

[1] Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for Boiler House #2 Fuel Switching

Notes

KJ 2-12-14

1 This option involves replacment of existing burners in the boiler house. There are five boilers, each equipped with 4 natural gas burners. To burn 100% natural gas, these will need to be replaced with new low NOx burners. The natural gas burner upgrade will also necessitate the replacement of the natural gas supply piping to the burners to provide sufficient natural gas. This estimate is based on the natural gas utility providing gas supply to the property line, and USS providing installation of in-plant distribution piping.

4 Installed Equipment Costs for Boiler House #2 Fuel Switching

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	Burner System	1	CS	CS	North American Combustion , Inc.	20	$ 235,000	$4,700,000	2014	1	1	1	$ 4,700,000
2	Fuel Delivery System Replacement	2	CS	CS	CB&I Estimate	1	$ 1,390,046	$1,390,046	2014	1	1	1	$ 1,390,046
3													
4													
5													
6													
7													
8													
9													
10													
21													
													$ 6,090,046

Notes:

1. Burner system includes burner, fuel train/control valves, blower, and control panel (I&C).
2. Fuel delivery replacement sized based on 1,000 MMBtu/hr capacity, assumes that utility will bring NG to site. Tie point will be Zug Island Rd on north side. Fuel piping will be routed along existing structural support systsems. Pricing based on Sch. 40 CS.

5.0 Installed Equipment Costs for Boiler House #2 Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

5.1 Baseline Cost of Fuel -2010

Total Usage	4,216,399	MMBtu/yr		Btu/scf				
Baseline NG	424,030	MMBtu/yr	NG HHV	1012	NG	0.0006	251.40	lbs /yr
Baseline COG	875,590	MMBtu/yr	BFG HHV	89	COG	1.431	1,253,217.00	lbs /yr
Baseline BFG	2,916,778	MMBtu/yr	COG HHV	496	BFG	0.08279	241,472.12	lbs /yr
Annual Hours Operation	8,760	hrs/yr				Total	1,494,941	lbs /yr
Cost NG	$ 4.89	(Based on 2010 cost)					747.47	tons /yr
Cost COG	$ 2.92	(Based on 2010 Cost)						
Baseline Annual Cost	$ 4,630,232	(Cost NG and COG)						

5.2 Fuel Use After Fuel Switch

Total Rating	4,216,399	MMBtu/yr		Btu/scf				
Post Fuel Switch NG	1,299,621	MMBtu/yr	NG HHV	1012	NG	0.0006	770.53	lbs /yr
Post Fuel Switch COG	-	MMBtu/yr	BFG HHV	89	COG	1.431	-	lbs /yr
Post Fuel Switch BFG	2,916,778	MMBtu/yr	COG HHV	496	BFG	0.082787	241,472	lbs /yr
Annual Hours Operation	8,760	hrs/yr				Total	242,243	lbs /yr
Cost NG	$ 6.38	(Based on average historical USS natural gas prices)					121.12	tons /yr
Future Projected Annual Cost	$ 8,291,583	(Cost NG and COG)						

Post Fuel Switch SO_2 Emission Reduction: 626.35 tpy

Post Control SO_2 Factor: 0 057 lb/MMBtu

5.3 Baseline Fuel Cost - Fuel Swich Fuel Cost

$ 3,661,350

3.0 Operating Labor Cost

Burners	$ 18,980	26 $/hr	730	1 hr/shift x 2 shifts x 365 day/yr
Other	$ -	26 $/hr	0	-
Annual Total Operating Labor	**$ 18,980**			

4.0 Maintenance

Total Installed Direct Cost	$ 5,934,526	
Total Maintenance Materials	$ 148,363	Note 2
Total Maintenance Labor	$ 148,363	Note 2
Total Annual Maintenance Cost	**$ 296,726**	Note 3

TOTAL LABOR AND MATERIALS **$ 3,977,056**

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
4. Fuel SO_2 emission factors from 2013 Air Inventory.

Table B18b. Direct and Indirect Installation Costs, HSM Furnaces - Fuel Switching

Cost Item	Factor	Cost
Direct Costs		
Purchased Equipment Costs		
Primary Equipment[1]		$ 13,658,240
Ancilliary Equipment		$ -
Allowance for Unforseen		$ 1,365,824
Instrumentation	0.04	$ 600,963
Sales Taxes	0.06	$ 901,444
Freight	0.05	$ 751,203
Purchased Equipment Cost, PEC		$ 17,277,674
Direct Installation Costs		
Foundations and Supports	0.05	$ 751,203
Handling and Erection	0.45	$ 6,801,702
Electrical	0.056	$ 841,348
Piping	0.07	$ 1,051,684
Ductwork	0.03	$ 450,722
Painting	0.01	$ 76,623
Direct Installation Costs, DC		$ 9,973,282
Site Preparation		$ 20,000
Buildings		$ -
Total Direct Costs (PEC +DC)		$ 27,270,956
Indirect Costs (Installation)		
Engineering	0.15	$ 2,591,651
Construction an Field Expenses	0.1	$ 1,727,767
Contractor Fees	0.1	$ 1,727,767
Startup	0.006	$ 103,666
Performance Test	0.02	$ 345,553
Model Study	0	$ -
Contingencies	0.1	$ 1,727,767
Two-Week Lost Production at the HSM		$ 15,600,000
Total Indirect Costs, IC		$ 23,824,173
Total Installed Cost		**$ 51,095,128**

[1] Primary equipment includes : replacement low NOx burner systems. Also included is replacement of fuel line to handle added natural gas demand.

Table B18a. Annual Cost Factors, HSM Furnaces - Fuel Switching

Cost Item	Factor	Cost
Direct Annual Costs, DC		
Operating Labor		
Operator	General Operating	$ 18,980
Supervisor	15% of Operator	$ 2,847
Material	5% of Total Operating	$ 1,091
Maintenance		
Maintenance Employee	General Maintenance	$ 91,953
Supervisor	15% of Maintenance Labor	$ 16,227
Material	100% of Maintenance Labor	$ 108,180
Utilities		
Fuel Switch Replacement Cost		$ 15,001,179
Indirect Annual Costs, IC		
Administrative Charges	2% of Total Capital Investment	$ 1,021,903
Property Tax	1% of Total Capital Investment	$ 510,951
Insurance	1% of Total Capital Investment	$ 510,951
Overhead	60% of total Labor and Materials	$ 9,141,912
Capital Recovery	0.1098 x Total Capital Investment	$ 5,610,245
Total Annual Cost		$ 32,036,420
	2010 Uncontrolled SO_2 Actual Emissions (tpy)	*2240.1*
	Allowance for Uncontrolled Maint. Outages (tpy) - 15 days	*0.0*
	SO_2 Removal Efficiency	*99.92%*
	Post-Control Emission Factor (lb/MMBtu)	*0.0006*
	Control Cost Per Ton SO_2	***$ 14,295***

[1] Capital Recovery Factor is derived from EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, January 2002, Chapter 2, pp. 2-21, based on a 15 year life and 7 percent interest rate.

3. Installed Equipment Costs for HSM Fuel Switching

Notes

KJ 2-12-14

1 This option involves replacment of existing COG burners in the boiler house. There are five furnaces, each equipped with multiple natural gas and COG burners. To burn 100% natural gas, these will need to be replaced with new low NOx burners. The natural gas burner upgrade will also necessitate the replacement of the natural gas supply piping to the burners to provide sufficient natural gas. This esimate is based on the natural gas utility providing gas supply to the property line, and USS installation of in-plant distribution piping.

4 Installed Equipment Costs for HSM Fuel Switching

BY: KJ 2-12-14

Equipment Cost Summary

4.1 Equipment Cost Summary

No.	Description	Notes	Base Materials	Required Materials	Basis For Estimate	No. Required	Unit Cost	Extended Cost (Base Year)	Base Year	Base Cost Factor	Current Year Cost Factor	Material Factor	Extended Cost (Current Year)
1	COG to NG Replacement Burners 12.5 MM	1	CS	CS	North American Combustion , Inc.	75	$ 65,000	$4,875,000	2014	1	1	1	$ 4,875,000
2	COG to NG Replacement Burners 17.5 MM	2	CS	CS	North American Combustion , Inc.	80	$ 80,000	$6,400,000	2014	1	1	1	$ 6,400,000
3	Panels and Instrumentation	3	-	-	North American Combustion , Inc.	5	$ 100,000	$500,000	2014	1	1	1	$ 500,000
4	Panels and Instrumentation	4	-	-	North American Combustion , Inc.	5	$ 100,000	$500,000	2014	1	1	1	$ 500,000
5	Fuel Delivery System Replacement	2	CS	CS	CB&I Estimate	1	$ 1,383,240	$1,383,240	2014	1	1	1	$ 1,383,240
6													
7													
8													
9													
10													
21													
													$ 13,658,240

Notes:

1. Burner system includes burner, fuel train/control valves, blower.
2. Burner system includes burner, fuel train/control valves, blower.
3. Panels for Smaller Burners. Actual configuration of panels will depend on detailed systems control analysis.
4. Panels for Larger Burners. Actual configuration of panels will depend on detailed systems control analysis.

5.0 Installed Equipment Costs for HSM Fuel Switching

Utilities, Materials, Reagents, Waste Streams, O&M

By: KJ 2-12-14

5.1 Baseline Cost of Fuel -2010

Total Usage	5,930,934	MMBtu/yr							
Baseline NG	2,801,957	MMBtu/yr	NG HHV	1012	NG	0 0006	1,661.24	lbs /yr
Baseline COG	3,128,978	MMBtu/yr	BFG HHV	89	COG	1.431	4,478,450.16	lbs /yr
Baseline BFG	-	MMBtu/yr	COB HHV	496	BFG	0.08279	-	lbs /yr
Annual Hours Operation	8,760	hrs/yr				Total	4,480,111	lbs /yr
Cost NG	$ 4.89	(Based on 2010 cost)					2,240.06	tons/yr
Cost COG	$ 2.92	(Based on 2010 Cost)						
Baseline Annual Cost	$ 22,838,183	(Cost NG and COG)						

5.2 Fuel Use After Fuel Switch

Total Rating	5,930,934	MMBtu/yr						
Post Fuel Switch NG	5,930,934	MMBtu/yr	NG HHV	1012	NG	0 0006	3,516.36	lbs /yr
Post Fuel Switch COG	-	MMBtu/yr	BFG HHV	89	COG	1.431	-	lbs /yr
Post Fuel Switch BFG	-	MMBtu/yr	COG HHV	496	BFG	0.082787	-	lbs /yr
Annual Hours Operation	8,760	hrs/yr				Total	3,516	lbs /yr
Cost NG	$ 6.38	(Based on average historical USS natural gas prices)					1.76	tons /yr
Future Projected Annual Cost	$ 37,839,362	(Cost NG and COG)						

Post Fuel Switch SO_2 Emission Reduction 2,238.3 tpy

Post Control SO_2 Factor: 0 0006 lb/MMBtu

5.3 Baseline Fuel Cost - Fuel Swich Fuel Cost

$ 15,001,179

3.0 Operating Labor Cost

Burners	$ 18,980	26 $/hr	730	1 hr/shift x 2 shifts x 365 day/yr
Other	$ -	26 $/hr	0	-
Annual Total Operating Labor	**$ 18,980**			

4.0 Maintenance

Total Installed Direct Cost	$ 4,327,217	
Total Maintenance Materials	$ 108,180	Note 2
Total Maintenance Labor	$ 108,180	Note 2
Total Annual Maintenance Cost	**$ 216,361**	Note 3

TOTAL LABOR AND MATERIALS **$ 15,236,519**

Notes:

1. Supervisory labor derived from Guiance for Estimating Capital and Annual Cost of Air PollutionControl Systems, 1983, prepared for Ohio EPA, Table 5-1.
2. Maintenance and labor at 50% of total cost for maintenance and labor, Guidance for Estimating Capital and Annual Costs of Air Pollution Control Systems (1983), prepared for Ohio EPA.
3. Total maintenance cost estimated based on 5% of total direct cost. Derived from Estimating Costs of Air Pollution Control, William M Vatavuk, Lewis Publishers (1990), pp. 27.
4. Fuel SO_2 emission factors from 2013 Air Inventory.
5. Actual rating is 2660 MMBtu/hr. Firing rate adjusted using 2013 emission factors to reach the PTE of 620.6 lb/hr (2713 tpy).

Reasonably Available Control Technology (RACT) Analysis.

RACT analysis for the control of sulfur dioxide (SO_2) emissions for the River Rouge and Trenton Channel Power Plants.

DTE Electric Company
River Rouge and Trenton Channel Power Plants

April, 2014

Prepared for:

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Executive Summary

This document is a reasonably available control technology (RACT) analysis for the control of sulfur dioxide (SO_2) emissions from the coal-fired electric generating units at the River Rouge and Trenton Channel Power Plants. This RACT analysis evaluated eight control technologies in a "top-down" analysis, including wet and dry flue gas desulfurization (FGD), two options for dry sorbent injection, and low sulfur fuels, including natural gas, distillate fuel oil, low sulfur subbituminous coals, and a blend of low sulfur subbituminous and bituminous coals. With respect to natural gas and distillate fuel oil, these fuels are not technically feasible control technologies because the use of these fuels would change the fundamental nature of the affected coal-fired electric generating units and redefine the source. The following table summarizes the control options and the average cost effectiveness for each technically feasible control technology at the River Rouge and Trenton Channel Power Plants.

SO_2 control technologies and costs for the River Rouge and Trenton Channel Power Plants.

Control Technology Option	Achievable Emission Rate[a],	Average Control Cost, $ per ton	
	lb/mmBtu	RR2, RR3, TCHS[b]	TC9
1. Wet Flue Gas Desulfurization (wet FGD).	0.06	$7,230 to $11,610	$5,080
2. Dry Flue Gas Desulfurization (dry FGD).	0.08	$8,460 to $13,260	$6,020
3. Sorbent Injection (optimized for SO_2 control).	0.48 0.72[c]	$7,210 to $10,980	$6,750
4. Sorbent Injection (MATS Compliance).	0.72 1.02[c]	$15,530 to $31,030	$12,720
5. Low Sulfur Subbituminous Coal.	0.8	$1,970 to $2,240	$3,800 to $5,060
6. Low Sulfur Subbituminous / Bituminous Coal Blend.	1.2		
Current Allowable	**1.67**		

Footnotes

a. The achievable emission rate is based on a 12-month average.

b. RR2 means River Rouge Unit 2; RR3 means River Rouge Unit 3; TCHS means the Trenton Channel High Side Boilers 16, 17, 18, and 19; TC9 means Trenton Channel Unit 9.

c. The first emission rate for sorbent injection is for RR2, RR3, and TCHS based on reductions from low sulfur subbituminous coal (Option 5); the second rate is for TC9 based on reductions from the coal blend (Option 6).

Based on this RACT analysis, DTE Electric Company has concluded that an emission rate equal to the use of low sulfur subbituminous coal (which is the lowest SO_2 emitting coal available) is technically and economically feasible for the River Rouge Units 2 and 3, and for the Trenton Channel High Side Boilers 16, 17, 18, and 19. However, because Trenton Channel Unit 9 cannot achieve full capacity when firing only low sulfur subbituminous coal, the costs of this reduced electric output would range from $3,800 to $5,060 per ton of SO_2 controlled. In the individual years from 2016 to 2022, these costs may be more than $11,200 per ton of SO_2 controlled. Based on these high costs, DTE Electric Company has concluded that the use of only low sulfur subbituminous coals is not economically feasible for Trenton Channel Unit 9.

Based on this RACT analysis, the following sulfur dioxide (SO_2) limits represent RACT for the River Rouge and Trenton Channel Power Plants.

Proposed SO_2 RACT limits for the River Rouge and Trenton Channel Power Plants.

Units	RACT Emission Limits
River Rouge Unit 2	0.8 lb/mmBtu, based on a 12-month rolling average.
River Rouge Unit 3	0.8 lb/mmBtu, based on a 12-month rolling average.
River Rouge Units 2 and 3 Combined	77.22 tons per day, based on a 24-hour or daily basis.
Trenton Channel Boilers 16 - 19	0.8 lb/mmBtu, based on a 12-month rolling average.
Trenton Channel Unit 9	1.2 lb/mmBtu, based on a 12-month rolling average.
Trenton Channel Boilers 16 - 19 and Unit 9	117.83 tons per day, based on a 24-hour or daily basis.

The proposed long term limit of 0.8 lb/mmBtu would result in a 52% reduction in the allowable emissions from the River Rouge Units 2 and 3, and the Trenton Channel Power Plant High Side Boilers 16, 17, 18, and 19. The proposed long term limit of 1.2 lb/mmBtu would result in a 28% reduction in the allowable emissions for Trenton Channel Unit 9. The reductions in potential SO_2 emissions based on these limits are summarized in the following table.

Comparison of the current potential SO_2 emissions to the potential emissions based on the proposed RACT limits.

Unit	Potential to Emit, tons per year	
	Current	Proposed
River Rouge Unit 2	15,768	7,989
River Rouge Unit 3	18,433	9,356
Trenton Channel Boilers 16, 17, 18, and 19	22,112	10,593
Trenton Channel Unit 9	33,134	23,810
Total	89,447	51,747

Although wet and dry FGD systems can reduce SO_2 emissions by 90 to 95%, the costs for both wet and dry FGD systems exceed $5,080 per ton of SO_2 controlled for all of the units at their expected utilization equal to a 55% capacity factor. The high costs for wet and dry FGD systems reflect the high capital costs of these technologies. For both power plants, these costs are estimated at $865 million for wet limestone forced oxidation (wet FGD) systems, and $990 million for lime spray dry FGD systems. Based on these high costs, wet or dry FGD systems are not economically feasible control technologies.

This analysis included two levels of reduction for sorbent injection. The first level is based on the use of sorbent injection optimized for SO_2 control. This option is expected to achieve an SO_2 control efficiency of at least 40%. However, the use of sorbent injection optimized for SO_2 control is also not economically feasible, with average costs exceeding $6,750 per ton of SO_2 controlled for all of the units at their expected utilization equal to a 55% capacity factor. These power plants will require the use of sorbent injection to comply with the Mercury and Air Toxics Standards (MATS) under 40 CFR 63, Subpart UUUUU beginning in 2016. Therefore, the second level of control represents the SO_2 reduction which may occur using sorbent injection to achieve the MATS standards. The use of sorbent injection to reduce hydrogen chloride (HCl) emissions for MATS compliance is expected to achieve a 10% incidental reduction in SO_2 emissions. However, the cost effectiveness for the control of SO_2 emissions based on the reduction achieved through the use of sorbent injection for MATS compliance is also not economically feasible, with costs exceeding $12,720 per ton of SO_2 controlled for all units.

The River Rouge and Trenton Channel Power Plants currently utilize a blend of low sulfur bituminous and low sulfur subbituminous coals. The use of only low sulfur subbituminous coal (which is the lowest SO_2 emitting coal available) would further reduce SO_2 emissions from these power plants. For the River Rouge Units 2 and 3, and the Trenton Channel High Side Boilers 16, 17, 18, and 19, an SO_2 emission rate equal to the rate achieved using only low sulfur subbituminous coal is technically and economically feasible, and is expected to reduce SO_2 emissions to less than 0.8 lb/mmBtu based on a 12-month average, and a mass emission rate equal to 1.3 lb/mmBtu based on a 24-hour or daily average. The short term achievable emission rate for each boiler is based on the mass emission rate for the boiler, expressed in tons per day. This form of the short term emission limit is consistent with the current SO_2 emission limits for these power plants.

Trenton Channel Unit 9, like the other units, was designed to fire bituminous coals. However, Trenton Channel Unit 9 cannot achieve full capacity when firing only low sulfur subbituminous coal. Because low sulfur subbituminous coals have a much lower heat value than bituminous coals, firing only low sulfur subbituminous coals in this unit would reduce the steam output of the boiler and reduce the maximum electric generating capacity or derate the unit by approximately 50 MW. The costs of this reduced electric output would include capacity costs and replacement power costs. For the Trenton Channel Unit 9, the average cost effectiveness for the use of only subbituminous coal would range from $3,800 to $5,060 per ton of SO_2 controlled. This cost is not economically feasible for Unit 9.

Table of Contents

Figures

Tables

Attachments

1. CUECost - Air Pollution Control Systems Economics Spreadsheet for the River Rouge and Trenton Channel Power Plants. Analysis based on 55% utilization for each unit.

Chapter 1. Introduction.

On June 3, 2010, EPA revised the primary sulfur dioxide (SO_2) National Ambient Air Quality Standard (NAAQS) by establishing a new 1-hour standard of 75 parts per billion (ppb). EPA must designate areas as "nonattainment," "attainment," or "unclassifiable" for this standard. On February 6, 2013, EPA sent a letter to the State of Michigan with its intended designations. This letter indicated a proposed nonattainment area including portions of Wayne County, Michigan. DTE Energy's River Rouge and Trenton Channel Power Plants are located within the recommended nonattainment area.

The nonattainment area plan provisions under section 172(c) of the Clean Air Act (CAA) set out the planning requirements for areas not meeting a NAAQS. One plan requirement is the application of reasonably available control technology (RACT) controls on existing sources in the nonattainment area. Section 172(c)(1) of the CAA states: "Such plan provisions shall provide for the implementation of all reasonably available control measures as expeditiously as practicable (including such reductions in emissions from existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology) and shall provide for attainment of the National Primary Ambient Air Quality Standards." The U.S. EPA states that RACT means devices, systems, process modifications, or other apparatus or techniques that are reasonably available, taking into account the necessity of imposing such controls in order to attain and maintain the NAAQS and the social, environmental, and economic impact of such controls.

This RACT analysis for the control of sulfur dioxide (SO_2) emissions from the River Rouge and Trenton Channel Power Plants provides specific information on SO_2 reduction strategies that are available and technologically feasible for the affected coal-fired electric generating units. Evaluated technologies include fuel switching or cleaning, and post combustion control systems including wet and dry flue gas desulfurization (FGD), and dry sorbent injection. Each technology examined includes an estimate of the SO_2 reduction in tons per year, and also includes a cost evaluation for each technically feasible reduction strategy, expressed in dollars per ton of pollutant controlled.

With respect to low sulfur containing fuels, this RACT analysis includes an evaluation of low sulfur coal, as well as low sulfur distillate fuel oil and natural gas as new primary fuels. However, the use of distillate fuel oil and natural gas as primary fuels are not technically feasible control technologies, since the use of these fuels would change the fundamental nature of the affected coal-fired boilers and redefine the source. The U.S. EPA has a long standing policy that the requirement to apply BACT or RACT is not a means to redefine the source. In the U.S. EPA guidance document *PSD and Title V Permitting Guidance For Greenhouse Gases*, EPA-457/B-11-001, March 2011, page 29, EPA states: "For example, when an applicant proposes to construct a coal-fired steam electric generating unit, EPA continues to believe that permitting authorities can show in most cases that the option of using natural gas as a primary fuel would fundamentally redefine a coal-fired electric generating unit."

Chapter 2. Affected Power Plants.

2.1 River Rouge Power Plant.

The River Rouge Power Plant is located in the City of River Rouge, Wayne County and operates under renewable operation permit (ROP) No. MI-ROP-B2810-2012. The River Rouge Power Plant has three electric generating units. Unit 1 has a 2,400 mmBtu per hour natural gas-fired boiler which is not part of this analysis. Units 2 and 3 are solid fuel-fired boilers rated at 2,280 and 2,670 mmBtu per hour, respectively. Units 2 and 3 have nameplate electric generating capacities of 292 and 358 MW, respectively. Both of these boilers are permitted to fire pulverized coal, natural gas, blast furnace gas, and coke oven gas. Units 2 and 3 are exhausted to separate stacks. The stack dimensions are included in Table 1.

Table 2 is a summary of the current potential or allowable SO_2 emissions based on the current emission limits in ROP MI-ROP-B2810-2012. Past actual SO_2 emissions from the U.S. EPA's Air Market's Program database are summarized in Table 3. From Tables 2 and 3, the actual SO_2 emissions in 2013 were 9,214 tons per year, as compared to a current allowable rate of 33,638 tons per year.

The River Rouge Power Plant also has four (4) distillate fuel oil-fired generators rated at 2.75 MW each. ROP No. MI-ROP-B2810-2012 limits SO_2 emissions to 120 parts per million (ppm) by volume at 50% excess air, equal to an SO_2 emission rate of 0.27 lb/mmBtu. These generators are not part of this analysis.

TABLE 1. Boiler stack data for the River Rouge Power Plant.

Boiler	Stack Height feet
EU-Boiler#2	385
EU-Boiler#3	425

TABLE 2. Potential SO_2 emissions for the River Rouge Power Plant Units 2 and 3.

Boiler	Boiler Rating	Allowable SO_2 Emission Rate		Potential Emissions
	mmBtu/hour	lb/mmBtu	ton/day	ton/year
EU-Boiler#2	2,280	1.67	43.20	15,768
EU-Boiler#3	2,670	1.67	50.50	18,432
TOTAL			**93.70**	**34,200**

TABLE 3. Actual SO_2 emissions for the River Rouge Power Plant Units 2 and 3.

Unit ID	Year	Actual SO_2 Emissions	
		lb/mmBtu (annual ave.)	ton/year
2	2013	0.71	4,355
3		0.85	4,859
TOTAL		**0.78**	**9,214**
2	2012	0.75	3,705
3		0.68	4,497
TOTAL		**0.71**	**8,202**
2	2011	0.86	5,893
3		0.75	4,757
TOTAL		**0.80**	**10,650**

FIGURE 1. River Rouge Power Plant located at 1 Belanger Park Drive, River Rouge.

2.2 Trenton Channel Power Plant.

The Trenton Channel Power Plant is located in the city of Trenton, Wayne County, and operates under ROP No. 199600204. The Trenton Channel Power Plant consists of five coal and oil fired boilers, and five oil-fired Slocum peaker generating units. Boilers 16, 17, 18, and 19 are similar, tangentially fired, coal-fired boilers with a combined heat input capacity of 3,023 mmBtu per hour for all four boilers. Boiler 9A is a coal-fired boiler with a rated heat input capacity of 4,530 mmBtu per hour. This boiler serves an electric generator with a nameplate capacity of 520 MW(e). Boilers 16, 17, 18, and 19 are exhausted to a common stack which is 559 feet above grade. Boiler 9A is exhausted to a separate dedicated stack which is 561 feet above grade. The stack dimensions are included in Table 4.

In accordance with ROP No. 199600204, Table F-1.2, the sulfur content of the coal as fired in boilers 16, 17, 18, 19, and 9A shall not exceed 0.83 pounds per mmBtu of heat input (i.e., an emission limit of 1.67 lb SO_2/mmBtu), based on a monthly average. In addition, SO_2 emissions may not exceed 151.36 tons per day and 55,246.4 tons per year from all boilers combined. Table 5 is a summary of the current potential or allowable SO_2 emissions based on the current emission limits in ROP No. 199600204. Past actual SO_2 emissions for the Trenton Channel Power Plant from the U.S. EPA's Air Market's Program database are summarized in Table 6.

TABLE 4. Boiler stack data for the Trenton Channel Power Plant.

Boiler	Stack Height feet
Boiler#16, 17, 18, and 19	559
Boiler #9A	561

TABLE 5. Potential SO_2 emissions for the Trenton Channel High Side and Unit 9.

Boiler	Boiler Rating	Allowable SO_2 Emission Rate		Potential Emissions
	mmBtu/hour	lb/mmBtu	ton/day	ton/year
Boilers 16, 17, 18, and 19	3,023	1.67	60.58	22,112
Unit 9A	4,530	1.67	90.78	33,134
TOTAL			**151.36**	**55,246**

TABLE 6. Actual SO_2 emissions for the Trenton Channel Power Plant.

Unit ID	Year	Actual SO_2 Emissions	
		lb/mmBtu (annual ave.)	ton/year
16	2013	0.79	766
17		0.79	1,096
18		0.78	852
19		0.79	1,023
9A		1.18	16,254
TOTAL		**1.08**	**19,992**
16	2012	1.13	1,252
17		1.20	1,508
18		1.12	1,221
19		1.18	1,445
9A		1.22	16,999
TOTAL		**1.21**	**22,426**
16	2011	1.29	1,669
17		1.29	1,478
18		1.29	1,333
19		1.29	1,818
9A		1.22	16,421
TOTAL		**1.24**	**22,720**

FIGURE 2. Trenton Channel Power Plant located at 4695 Jefferson Ave., W Trenton.

Chapter 3. RACT Analysis Methodology.

3.1 Reasonably Available Control Technology (RACT).

The nonattainment area plan provisions under section 172(c) of the Clean Air Act (CAA) require the application of Reasonably Available Control Technology (RACT) for the control of air emissions for existing sources located in areas that are not meeting national ambient air quality standards (NAAQS). EPA has defined RACT as: "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility" (44 FR 53762; September 17, 1979). The RACT process determines, and then requires the use of reasonable available control requirements to reduce or limit emissions. These requirements identify the lowest emission limit that a source is capable of meeting after considering technological and economic feasibility.

3.2 Top Down Control Technology Analysis Methodology.

The U.S. EPA recommends a "top-down" approach in conducting a BACT or LAER control technology review. This method evaluates progressively less stringent control technologies until a level of control considered BACT is reached, based on the environmental, energy, and economic impacts. The five steps of a top-down BACT analysis are:

1. Identify all available control technologies with practical potential for application to the emission unit and regulated pollutant under evaluation;
2. Eliminate all technically infeasible control technologies;
3. Rank remaining control technologies by effectiveness and tabulate a control hierarchy;
4. Evaluate most effective controls and document results; and
5. Select BACT, which will be the most effective practical option not rejected, based on economic, environmental, and/or energy impacts.

The impact analysis of any BACT review includes an evaluation of environmental, energy, technical, and economic impacts. The most important issue of the BACT review is generally the economic impact. The economic impact of a control option is assessed in terms of cost effectiveness and ultimately, whether the option is economically reasonable. The economic impacts are reviewed on a cost per ton controlled basis, as directed by the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Cost Control Manual, Fifth Edition.

Because this review methodology is a well-accepted method for evaluating controls for emission sources, this top down control technology analysis methodology has been used in this RACT analysis.

3.3 New Versus Modified Facilities.

There can be significant differences in the technical and economic feasibility of retrofitting controls on existing units, versus the use of these same controls on new units. In addition, a given control technology may not be able to achieve the same level of control when retrofitted onto existing units as the same control technology can achieve on new units. Retrofitting controls on existing units can also have significantly different costs as compared to the use of these same technologies on new units. Retrofitting controls on existing units can have numerous issues, including site constraints and room for the new controls, demolition requirements for existing controls, and unit down time during construction and interconnection of the new systems.

3.4 Technical Feasibility.

Step 2 of the RACT analysis involves the evaluation of all of the identified available control technologies from Step 1 to determine their technical feasibility. A control technology is technically feasible if it has been previously installed at full scale and operated successfully at a similar emission source, or there is technical agreement that the technology can be applied to the emission source. Technical infeasibility is demonstrated through clear physical, chemical, or other engineering principles that demonstrate that technical difficulties preclude the successful use of the control option.

Under the U.S. EPA's top down BACT analysis methodology, the technology must be commercially available for it to be considered as a potential control option. EPA's New Source Review Workshop Manual, page B.12 states, "Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."

In general, if a control technology has been "demonstrated" successfully for the type of emission source under review, then it would normally be considered technically feasible. For an undemonstrated technology, "availability" and "applicability" determine technical feasibility. A technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

Applicability involves not only commercial availability (as evidenced by past or expected near-term deployment on the same or similar type of emission source), but also involves consideration of the physical and chemical characteristics of the gas stream to be controlled. A control method applicable to one emission source may not be applicable to a similar source depending on differences in physical and chemical gas stream characteristics.

3.5 Economic Feasibility.

Economic feasibility is normally evaluated according to the average and incremental cost effectiveness of the control option. From the U.S. EPA's New Source Review Manual, page B.31, average cost effectiveness is the dollars per ton of pollutant reduced. The incremental cost effectiveness is the cost per ton reduced from the technology being evaluated as compared to the next lower technology.

As noted above, EPA has defined RACT as: "the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility" (44 FR 53762; September 17, 1979). U.S. EPA guidance from 1994 indicates that cost effectiveness should be within $160 to $1,300 per ton of pollutant controlled[1]. Based on the U.S. Bureau of Labor Statistics Consumer Price Index (CPI) Calculator, available at http://www.bls.gov/data/inflation_calculator.htm, $1.00 in 1994 is equal to $1.58 in 2014. ***Therefore, the equivalent cost effectiveness, expressed in 2014 dollars, is $250 to $2,050 per ton of pollutant controlled.***

In the EPA's New Source Review Manual, page B.37, average cost effectiveness is calculated as:

$$\text{Average Cost Effectiveness (\$ per ton removed)} = \frac{\text{Control option annualized cost}}{\text{Baseline emission rate} - \text{Control option emissions rate}}$$

The average cost effectiveness is based on the overall reduction in the air pollutant from the baseline emission rate. The baseline emission rate represents uncontrolled emissions for the source. However, cost effectiveness may be estimated based *on the realistic operation of the emissions unit in question*. In the EPA's New Source Review Manual, page B.37, the EPA states "In addition, historic upper bound operating data, typical for the source or industry, may be used in defining baseline emissions in evaluating the cost effectiveness of a control option for a specific source. For example, if for a source or industry, historical upper bound operations call for two shifts a day, it is not necessary to assume full time (8760 hours) operation on an annual basis in calculating baseline emissions. ***For this reason, costs in this analysis are calculated based on the expected normal utilization of these units of 55%.***

In the cost analyses presented in this RACT analysis, the capital recovery costs (the annual cost required to pay for the total project cost) ***are based on a project life of 7 years***. A 7 year project life is used because the River Rouge Units 2 and 3 were constructed in 1954 and 1955, the Trenton Channel Highside Boilers 16 – 19 were constructed in 1948 – 1949, and the Trenton Channel Boiler 9A was constructed in 1965. These electric generating units are therefore from 49 to 66 years old. The construction of post combustion wet and dry FGD systems would require at least 3 years to complete after project approval; the construction of sorbent injection systems will require at least 2 years to complete. Therefore, at the end of a 7-year project cost recovery period, these units would be from 58 to 75 years old. A longer project recovery period is simply not compatible with the age of these units.

[1] From the U.S. EPA memorandum *Cost-Effective Nitrogen Oxides (NOx) Reasonably Available Control Technology (RACT)*, from D. Kent Berry, Acting Director Air Quality Management Division (MD-15), March 16, 1994, available at http://www.epa.gov/ttn/caaa/t1/memoranda/costcon.pdf .

Chapter 4. Potential SO_2 Control Technologies.

Step 1 of this RACT analysis involves the identification of all available potential control technologies for the control of sulfur dioxide (SO_2) emissions from fossil fuel-fired electric generating units.

SO_2 emissions from fossil fuel-fired electric generating units result from the oxidation of sulfur compounds in the fuel. During combustion, the majority of the fuel sulfur is emitted as SO_2. A small portion of the sulfur is further oxidized to sulfur trioxide (SO_3). When the flue gas temperature drops below the dew point temperature, sulfur trioxide is converted to sulfuric acid (H_2SO_4). Therefore, control technologies which control SO_2 emissions also reduce sulfuric acid mist emissions to varying degrees. A portion of the SO_2 and SO_3 in the flue gas may react with alkaline products in the ash to form filterable particulate matter. A portion of the sulfur compounds are also bound with bottom ash and are removed in the bottom ash. ***In this control technology review, all controls are evaluated based on the assumption that 100% of the sulfur in the fuel is converted to SO_2.***

Potential sulfur dioxide (SO_2) control technologies include pre-combustion controls such as low sulfur fuels, and post combustion controls, such as flue gas desulfurization. The following references were used to identify potential SO_2 control technologies: *Controlling SO_2 Emissions: A Review of Technologies* (EPA-600/R-00-093, October 2000), the U.S. EPA's RACT/BACT /LAER Clearinghouse (RLBC), the U.S. EPA's National Coal-Fired Utility Projects Spreadsheet Updated July 2007, and numerous air permits issued by states and the U.S. EPA. Technologies identified to control SO_2 emissions from pulverized coal-fired EGUs are summarized below.

Potential available SO_2 control technologies.

Fuel Cleaning	• Coal Washing
	• Low Sulfur Fuels
	    • Low Sulfur Coal
	    • Natural Gas
	    • Distillate Fuel Oil
	    • Biomass

Post Combustion Controls	• Wet Flue Gas Desulfurization (FGD) • Dry and Semi-Dry FGD • Circulating Fluidized Bed (CFB) Dry FGD • Sorbent Injection • Emerging Control Technologies.

Chapter 5. Technically Feasible SO_2 Control Technologies.

Step 2 of this RACT analysis involves the evaluation of the identified available control technologies from Step 1 to determine their technical feasibility. A control technology is technically feasible if it has been previously installed and operated successfully at a similar emission source of comparable size, or there is technical agreement that the technology can be applied to the emission source. Technical infeasibility is demonstrated through clear physical, chemical, or other engineering principles that demonstrate that technical difficulties preclude the successful use of the control option. In addition, the technology must be commercially available for it to be considered technically feasible. Finally, technologies which fundamentally redefine a source are also not technically feasible control options.

5.1 Low Sulfur Fuels.

Because SO_2 emissions occur from the oxidation of sulfur in the fuel, SO_2 emissions may be reduced directly by reducing the sulfur content of the fuel. Potential low sulfur fuels include low sulfur coal(s), low sulfur distillate fuel oil, natural gas, and biomass fuels.

5.1.1 Low Sulfur Coal.

All of the affected coal-fired boilers, including the River Rouge Boilers 2 and 3, and the Trenton Channel Boilers 16, 17, 18, 19, and 9A, are subject to the MDEQ rule R 336.1401, Emission of sulfur dioxide from power plants. The applicable requirement for these boilers in R 336.1401, Table 41 is an SO_2 limit of 1.67 pounds of SO_2 per million Btu of heat input. This limit is expressed on a 24-hour basis for the River Rouge Boilers 2 and 3, and is based on a monthly average for the Trenton Channel Boilers 16, 17, 18, 19, and 9A. Low sulfur coal is available and technically feasible for these boilers. However, the use of 100% low sulfur subbituminous coals can have adverse effects on these boilers, including reduced maximum output capabilities or derating due to the lower heat content of these low sulfur coals. There is also inherent variability in sulfur content since coal from one mine or area can have a significantly different sulfur content than from another mine or area in the same region.

5.1.2 Natural Gas, Low Sulfur Fuel Oil, and Biomass Fuels.

All of the affected coal-fired boilers, including the River Rouge Boilers 2 and 3, and the Trenton Channel Boilers 16, 17, 18, 19, and 9A, were designed and constructed as coal-fired electric generating units. The purpose of these units is to provide baseload electric generating capacity from the use of coal as the primary fuel. These units were not designed to burn natural gas or low sulfur distillate fuel oil to generate a meaningful portion of the unit load. These units were designed to utilize coal as the primary fuel, which is clearly evident by the complex and advanced material handling systems and air quality control systems which are installed on these boilers.

The U.S. EPA has a long standing policy that the requirement to apply BACT or RACT is not a means to redefine the source. The U.S. EPA prepared a guidance document for greenhouse gases titled *PSD and Title V Permitting Guidance For Greenhouse Gases*, EPA-457/B-11-001, March 2011, page 29 to assist permit writers and permit applicants in addressing the PSD permitting requirements for greenhouse gases. On page 29, EPA states:

> The CAA includes "clean fuels" in the definition of BACT.[71] Thus, clean fuels which would reduce GHG emissions should be considered, but EPA has recognized that the initial list of control options for a BACT analysis does not need to include "clean fuel" options that would fundamentally redefine the source. **Such options include those that would require a permit applicant to switch to a primary fuel type (*i.e.*, coal, natural gas, or biomass) other than the type of fuel that an applicant proposes to use for its primary combustion process. For example, when an applicant proposes to construct a coal-fired steam electric generating unit, EPA continues to believe that permitting authorities can show in most cases that the option of using natural gas as a primary fuel would fundamentally redefine a coal-fired electric generating unit."** (*emphasis added*)

Based on U.S. EPA policies and guidance, the switching to a different primary fuel type is not an available control alternative for this project, since the use of a different primary fuel such as natural gas or distillate fuel oil would redefine the project.

There may be other reasons that repowering with natural gas or fuel oil may be technically infeasible, including the availability of the fuel at the plant location. For example, the fuel oil required to replace 100% of the heat input for one of the River Rouge units would be at least 16,200 gallons per hour, or about 2 to 4 semi tanker trucks per hour. This extremely high oil consumption rate may be infeasible to implement at these power plants as a permanent replacement fuel.

With respect to biomass fuels, while biomass fuels have low sulfur contents, the use of biomass would redefine the design and purpose of these units. The design of these boilers would need to be fundamentally changed in order to allow the utilization of biomass in these units in place of pulverized coal. In addition, there is not a sufficient amount of biomass available in southeastern Michigan to provide the fuel requirements for these units.

5.1.3 Conclusions Regarding Low Sulfur Fuels.

Low sulfur coals are an available control technology for the coal-fired boilers at the River Rouge and Trenton Channel Power Plants. However, the use of natural gas, low sulfur fuel oil, or biomass as a means of reducing SO_2 emissions would result in a significant change to both the design and the purpose of these boilers. Therefore, the use of natural gas, low sulfur fuel oil, and biomass fuels are not technically feasible SO_2 control options for these boilers.

5.2 Fuel Cleaning.

Coal is a mineral consisting of a heterogeneous mixture of organic and inorganic matter. The impurities associated with coal may be classified as inherent or extraneous. Inherent impurities cannot be physically separated from coal. However, extraneous impurities such as rocks, scrap iron, and pyrite (iron disulfide, FeS_2) can be physically separated to varying degrees through coal cleaning. Sulfur is generally present in coal in three forms: pyritic, sulfate, or organic. The pyritic portion of sulfur in coal may vary from 10% to 80% of the total sulfur content. Large pyrite particles can be removed by physical cleaning. Sulfate forms of sulfur are usually calcium or iron sulfates, and generally account for less than 0.1% of the coal sulfur content. Organic sulfur is chemically bound to the coal and cannot be separated by coal cleaning. Therefore, fuel cleaning is only effective for coals containing high percentages of sulfur as pyrite.

In the coal cleaning process, "run-of-mine" coal is first cleaned of trash, crushed, and screened. The coal is then cleaned by gravity separation. In the gravity separation process, the desirable coal organic fraction floats in a separating fluid (usually an aqueous suspension of magnetite in water), while pyrite, soil, rock, and shale debris sink. The floating organic fraction is transferred to a dewatering system. Dewatering is a key cleaning step, since the reduction of water reduces shipping costs and improves the coal heating value. Nearly all of the bituminous coals from Illinois and Appalachia are washed before being shipped from the mine.

While coal cleaning can achieve substantial sulfur reductions on some coals (for example, 20 to 30% for Illinois bituminous coals), not all coals can be effectively washed. In particular, subbituminous coals have low sulfur, low ash and small coal particle sizes. Washing of subbituminous coals is not technically feasible because of the minimal improvement in sulfur content and the high energy requirements needed to effectively dewater the coal.

5.2.1 Technical Feasibility

Fuel cleaning is a technically feasible control option to reduce the sulfur content of Illinois and Appalachia bituminous coals with relatively high percentages of sulfur as pyrite. Fuel cleaning is not technically feasible for subbituminous coals because of the minimal improvement in sulfur content and the high energy requirements needed to effectively dewater the coal. In this RACT analysis, the use of low sulfur coals is effective, and in some cases the use of low sulfur coals may include fuel cleaning as part of the achieved low sulfur coal. However, fuel cleaning will not be considered separately from the use of low sulfur coal.

5.3 Flue Gas Desulfurization.

Flue Gas Desulfurization (FGD) technologies used for coal-fired boilers may be broadly classified as "wet" and "dry" systems. Wet FGD systems are characterized by low flue gas outlet temperatures, saturated or wet flue gas conditions, and a wet sludge reaction product which is dewatered before reuse or disposal. For most coals and boiler types, the flue gas saturation temperature is about 130 ^{o}F. In wet FGD applications, the primary particulate matter control system is typically located *upstream* of the wet FGD system so that the fly ash and FGD system reaction products are collected *separately*. This is necessary to avoid saturated conditions in the PM control system which would plug a fabric filter baghouse or dry ESP. This can also be advantageous for the beneficial reuse of fly ash and the wet FGD reaction products such as gypsum, since the ash and gypsum can be collected separately. Wet FGD systems are also characterized by relatively high water use as compared to dry FGD systems.

Conversely, dry FGD systems are characterized by outlet flue gas temperatures about 20 to 50 °F above the saturation point, or about 150 to 180 ^{o}F. In dry FGD applications, the particulate control system is located *downstream* of the dry FGD system so that the fly ash and the FGD reaction product are *commingled* into a single byproduct or waste stream. However, in retrofit applications such as the River Rouge and Trenton Channel boilers which already have dry ESPs, the semi-dry FGD system can be installed downstream of the dry ESP systems, so that the fly ash and FGD system reaction products may be collected *separately* much like a conventional wet FGD system. Finally, dry FGD systems are characterized by reduced water use as compared to wet FGD systems.

5.4 Wet Flue Gas Desulfurization.

Wet FGD is a well demonstrated technology for the control of SO_2 emissions from coal-fired electric generating units utilizing pulverized coal-fired boilers. In a wet FGD system, the flue gas is exposed to an alkaline reagent which reacts with SO_2 to form a solid. There are several alkaline reagents used in wet FGD systems, including water-based slurries of lime or limestone, liquors containing dissolved sodium or magnesium salts, or amine based liquors including ammonia. Most wet FGD systems use lime or limestone as the alkaline reagent and produce calcium sulfite and / or calcium sulfate (gypsum). A typical modern wet flue gas desulfurization system absorber tower is shown in Figure 3.

Regardless of the wet FGD design, the flue gas leaving the absorber will be saturated with water, and the stack will have a highly visible condensed moisture plume. The conditions downstream of the absorber are highly corrosive, requiring corrosion-resistant materials for the downstream ductwork and stack. Equipment is also needed to manage the condensation that occurs on the downstream ductwork and in the stack. The wet FGD reaction products also require dewatering, usually by a combination of hydroclones and vacuum filters. Relatively large areas are needed to manage the reagent processing and the byproduct dewatering and storage operations. These factors contribute to the capital and operating costs of wet FGD systems. Note that the FGD systems do not normally have bypass stacks. Therefore, the wet FGD systems must be operational when the units are firing coal to prevent damage to the stacks.

5.4.1 Wet Limestone with Forced Oxidation.

In recent years, the WFGD market has turned almost completely to the use of wet lime or limestone with forced oxidation on pulverized coal-fired boilers because it improves SO_2 control, reduces chemical scale formation, and produces gypsum, a stable and potentially valuable byproduct. Wet limestone with forced oxidation (LSFO) is a modification of the conventional wet limestone FGD process. A conventional wet limestone system forms a scrubber product composed mostly of calcium sulfite ($CaSO_3$). The LSFO process further oxidizes calcium sulfite to calcium sulfate dihydrate (gypsum, or $CaSO_4 \cdot 2H_2O$). The gypsum content of the scrubber sludge is typically 95% on a dry basis, making the sludge easier to dewater and much more valuable. Gypsum is a naturally occurring mineral that is mined around the world for use as a raw material in the manufacture of plaster, wallboard, Portland cement, agricultural soil conditioners, and various other products.

In a typical LSFO process, flue gas exits the primary particulate matter pollution control system such as an electrostatic precipitator at approximately 300 ^{o}F and enters a spray tower where an alkaline slurry consisting of limestone (calcium carbonate), calcium sulfite, and calcium sulfate is contacted with the flue gas. Through a series of reactions, SO_2 in the flue gas reacts with calcium carbonate in the limestone to form $CaSO_3$. The flue gas exits the absorption tower through a series of chevron mist eliminators to remove entrained moisture droplets. The calcium sulfite remains in the slurry which drains into a recirculation tank located at the bottom of the spray tower. By injecting air into the slurry using fans or blowers, the calcium sulfite is oxidized to $CaSO_4{\cdot}2H_2O$. A portion of the slurry in the recirculation tank is pumped back into the spray tower, and a portion is removed. The removed slurry is dewatered and stockpiled for transport offsite. The overall FGD reaction is:

$$CaCO_3(s) + SO_2(g) + \tfrac{1}{2}O_2(g) + 2H_2O \quad \rightarrow \quad CaSO_4{\cdot}2H_2O(s) + CO_2(g)$$

The LSFO process can achieve high levels of control on pulverized coal-fired boilers. Recent BACT determinations put the level of control in the 95-97% range. However, the same performance principle for any SO_2 control system is also true for the LSFO – as the boiler outlet SO_2 concentration decreases, the ability to achieve high control efficiencies also decreases. As a result, the higher level of performance for LSFO systems stated as a percentage reduction can only be achieved when the boiler is firing higher sulfur content fuels.

5.4.2 Advanced Wet FGD Designs.

The first FGD systems in the U.S. were installed largely in response to the 1971 Clean Air Act. Most of these original FGD systems were calcium based wet FGD systems. About half of these early systems were lime and the other half limestone. Many of the original FGD systems were plagued with operational issues that included scaling, plugging, and low SO_2 removal efficiency - generally less than 90%. These first wet FGD systems utilized spray tower absorbers, often without a perforated plate tray, as the method for contacting the flue gas with the alkaline reagent.

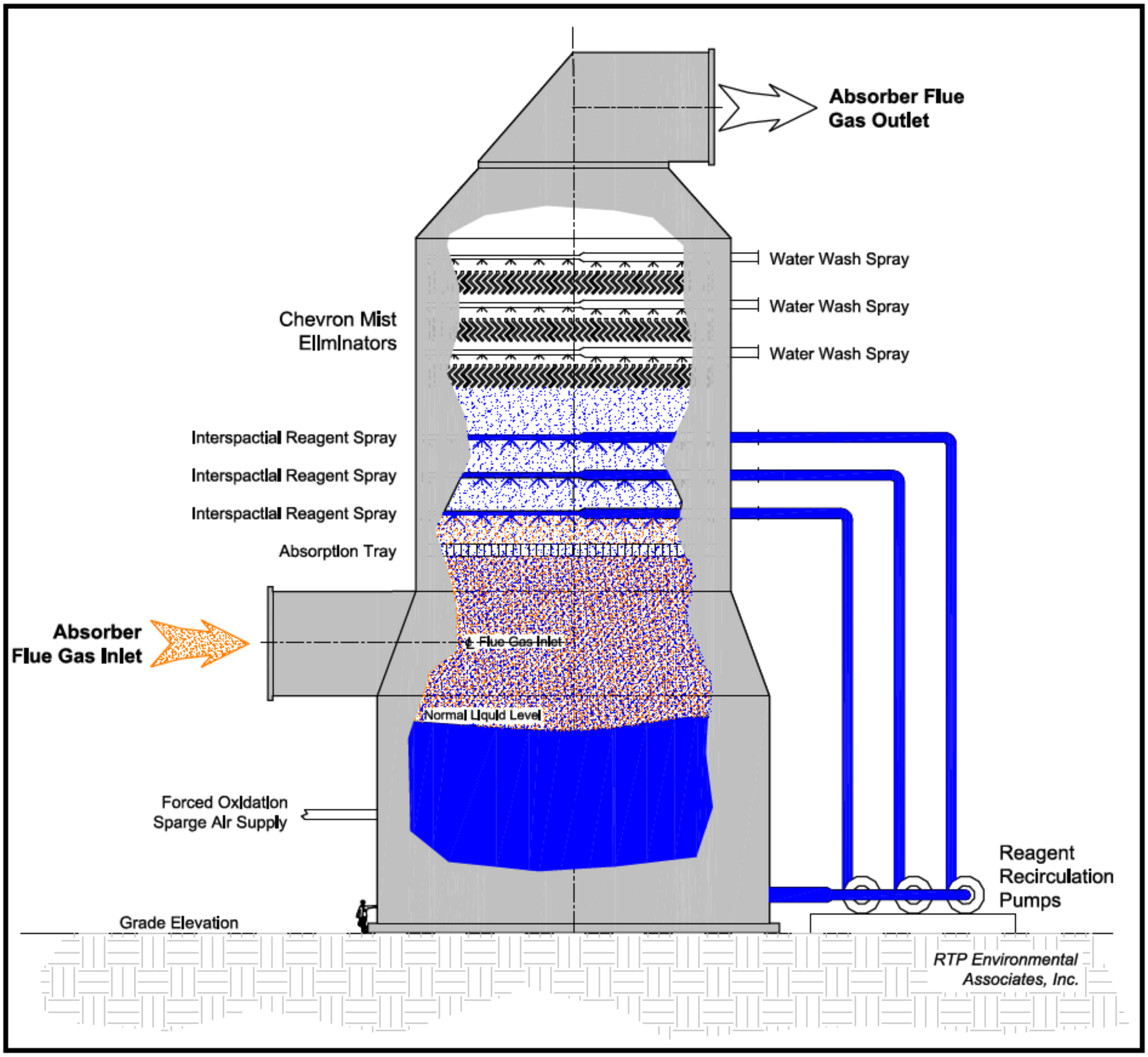
FGD systems installed in the 1990's were 2nd and 3rd generation systems which generally achieved greater than 90% SO_2 removal with improved reliability. The limestone systems installed during this time were mostly forced oxidation systems which demonstrated the ability to achieve similar performance and reliability as lime systems. The SO_2 removal efficiencies of the 2nd and 3rd generation systems were improved primarily by improving gas to liquid contact. These improvements include absorption trays with perforated plates and multiple levels of interspatial reagent spray nozzles.

FGD system suppliers have introduced several new designs to further improve the flue gas-to-liquid reagent contact and minimize operating costs. Designs such as the Jet Bubbling Reactor developed by Chiyoda and Alstom's Flowpac systems were developed to improve the gas-to-liquid contact by forcing the flue gas to bubble through the liquid reagent using a gas sparger design rather than spraying the alkaline slurry into the gas stream. Mitsubishi developed the Double Contact Flow Scrubber (DCFS) which uses 'fountains' of slurry to contact the flue gas. Babcock Power Environmental Inc. utilizes bidirectional sprays and wall rings to maximize contact between the flue gas and liquid reagent.

5.4.3 Technical Feasibility

As noted above, WFGD is a well demonstrated, technically feasible control technology for the control of SO_2 emissions from pulverized coal-fired boilers. Wet FGD is typically used on boilers combusting higher sulfur eastern bituminous coals, while dry FGD systems have typically used on boilers firing low sulfur western subbituminous coals.

FIGURE 3. Typical modern wet flue gas desulfurization system absorber tower.



5.5 Dry or Semi-Dry Flue Gas Desulfurization.

Dry or semi-dry FGD is a well demonstrated technology for the control of SO_2 emissions from coal-fired electric generating units. Like wet FGD systems, dry FGD systems can be divided into several types. Dry FGD systems involve injecting a dry sorbent into the furnace or flue gas duct; the by-product solids are normally collected with the boiler fly ash. In semi-dry FGD systems, the sorbent is introduced as an aqueous slurry or a humidified dry powder to improve SO_2 control efficiency. The water content is controlled so that the reaction by-products are dry solids. While the flue gas temperature in both dry and semi-dry FGD remains above the adiabatic saturation temperature, the semi-dry systems have lower flue gas exit temperatures and a closer approach to the saturation temperature. The primary PM control system for dry FGD applications is normally a fabric filter baghouse since this PM control technology can provide higher reagent utilization. In this type of application, the baghouse acts much like a fixed bed reactor, allowing for intimate contact between unreacted reagent and SO_2 gas in the filter cake.

Dry and semi-dry FGD systems do not have a saturated plume and therefore do not require the same design elements related to a saturated and corrosive plume as with wet FGD systems. Since the FGD reaction products are also dry, there is no need for dewatering equipment or a wastewater discharge. The reaction product is primarily calcium sulfite, with smaller amounts of calcium sulfate. Because of the calcium sulfite content, the dry FGD byproduct is usually unstable and will undergo pozzolanic (cementitious) reactions when wetted. This material has limited commercial value and is typically landfilled or used for mine fill.

5.5.1 Lime Spray Drying Absorber.

One of the most widely used semi-dry FGD technologies is the lime spray dry absorber (LSDA). The LSDA is a semi-dry FGD technology that is often used in low sulfur pulverized coal-fired boiler applications. The LSDA process employs a spray dryer absorber (SDA) and a downstream PM control device. The SDA introduces a lime or limestone slurry and flue gas at the top of an absorber vessel. Rotary atomizers or dual fluid nozzles are used to create a spray of atomized slurry droplets which are dispersed in the flue gas stream. The water in the slurry droplets evaporates as the flue gas passes through the absorber, cooling and humidifying the flue gas stream and rapidly drying the slurry to a powder. In practice, water is added to control the SDA outlet temperature to approximately 155^{o}F, or an approach temperature approximately 25^{o}F above the saturation temperature. SO_2 in the flue gas reacts with calcium hydroxide to form solid calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) according to the following overall equations:

$$2Ca(OH)_2\,(s) + 2SO_2\,(g) + 2H_2O\,(g) \rightarrow 2(CaSO_3 \bullet 2H_2O)$$

$$2Ca(OH)_2\,(s) + 2SO_2\,(g) + 2H_2O\,(g) + O_2 \rightarrow 2(CaSO_4 \bullet 2H_2O)$$

Fly ash, reaction products, and unreacted lime are captured downstream of the LSDA in the PM control system. A portion of the collected material in the PM control system is recycled back to the SDA to improve reagent utilization.

5.5.2 Advanced Semi-Dry FGD Systems.

Advanced Semi-Dry FGD systems include circulating fluidized bed (CFB) systems, hydrated lime injection systems such as Turbosorp, circulating dry scrubbers (CDS), and flash dry absorbers, also called novel integrated desulphurization system (NIDS). These systems are often utilized in circulating fluidized bed (CFB) boiler applications where excess lime (CaO) produced in the CFB boiler can be used to further reduce SO_2 emissions. The ash captured in the fabric filter baghouse which contains excess lime is hydrated to form calcium hydroxide ($Ca(OH)_2$). This hydrated ash is then reinjected into the flue gas in a reactor or vessel upstream of the baghouse.

These advanced semi-dry systems may be contrasted with conventional LSDA systems in that the ash is humidified but remains a free-flowing solid, as opposed to being hydrated to a slurry as in the LSDA process. This lower water content eliminates the need for slurry handling, atomization, and a large reactor or absorber vessel. Reinjecting a dry solid also allows the reagent to disperse rapidly in the flue gas. These systems may also be contrasted with conventional SDA systems in that the solids recirculation rate is 30 to 100 times, compared to 3 – 5 times in a conventional SDA system.

These semi-dry FGD systems have demonstrated the ability to achieve SO_2 emission reductions equivalent to or even greater than that achieved by conventional dry FGD systems and LSDA systems. For example, the CFB semi-dry FGD process uses lime, water and recycled solids from the CFB boiler and fabric filter baghouse in a fluidized bed reactor to form calcium sulfite and calcium sulfate as described above. In a CFB system, flue gas is introduced into the bottom of a vessel at high velocity through a venturi nozzle and is mixed with water, hydrated lime, recycled fly ash, and FGD reaction byproducts. The mixture of flue gas, water, and solids traverses the reactor in a highly turbulent fluidized bed. SO_2 in the flue gas reacts with calcium hydroxide in the reactor or on the fabric filter bags to form solid calcium sulfite and calcium sulfate. The injected water humidifies and cools the flue gas. By the time the particles leave the reactor, they are dry particulate matter which is captured in the PM control system.

5.5.3 Technical Feasibility.

Dry FGD systems, including lime spray drying absorbers, circulating fluidized bed semi-dry systems, hydrated lime injection systems, circulating dry scrubbers, and flash dryer absorbers, are all demonstrated, technically feasible control technologies for the control of SO_2 emissions from coal-fired boilers. Although advanced semi-dry systems are primarily used in fluidized bed boiler applications, not pulverized coal-fired boilers, these dry and semi-dry FGD systems are nevertheless technically feasible control options.

5.6 Sorbent Injection.

Sorbent injection systems are dry FGD systems in which a powdered sorbent is injected into the furnace or into downstream ductwork. Several types of sorbent injection systems are available, including furnace sorbent injection and duct or dry sorbent injection. Dry sorbent injection (DSI) is a dry FGD system. In a typical DSI system, the sorbents are either sodium or calcium-based materials which are injected either in the furnace, or in the downstream ductwork prior to the PM control system. Calcium-based sorbents include limestone and hydrated quicklime; sodium-based sorbents include sodium bicarbonate, and trona (sodium sesquicarbonate or $Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O$). Fly ash, sorbent reaction products, and unused sorbent are collected and commingled in the PM control system. DSI has typical SO_2 removal efficiencies of 10 to 50%, although removal efficiencies of up to 90% have been reported at very high molar ratio sorbent injection rates and for short test durations. However, this very high level of removal has not been demonstrated on a continuous basis.

Furnace sorbent injection is also a dry system. Sorbents such as limestone or hydrated lime are injected into the boiler furnace. The injection point is selected based on the temperature window that is required for the reagent, typically around 1,000 – 1,500°F. The reaction product and fly ash are collected in the PM collection system. Furnace sorbent injection systems designed specifically for SO_2 control may achieve SO_2 removal efficiencies of 25 to 50%. However, for fluidized bed boilers, furnace sorbent injection is capable of achieving 90% removal in high sulfur coal applications.

Sorbent injection systems may also be used for the control of acid gases which are also hazardous air pollutants (HAPs), such as hydrogen chloride (HCl). For example, trona reacts with acid gases including HCl, HF, SO_2, NO_x, and SeO_2 (selenium dioxide) to form solid salts according to the following example overall reactions:

Pollutant		Sorbent	Oxygen		Reaction Product	Water		Carbon Dioxide
3HCl	+	$Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O$		$\rightarrow$	3NaCl	+ $4H_2O$	+	$2CO_2$
3HF	+	$Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O$		$\rightarrow$	3NaF	+ $4H_2O$	+	$2CO_2$
$3SO_2$	+	2 [$Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O$]	+ $^3/_2O_2$	$\rightarrow$	$3Na_2SO_4$	+ $5H_2O$	+	$4CO_2$
$6NO_2$	+	2 [$Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O$]	+ $^3/_2O_2$	$\rightarrow$	$6NaNO_3$	+ $5H_2O$	+	$4CO_2$
$3SeO_2$	+	2 [$Na_2CO_3 \bullet NaHCO_3 \bullet 2H_2O$]	+ $^3/_2O_2$	$\rightarrow$	$3Na_2SeO_4$	+ $5H_2O$	+	$4CO_2$

DSI designed specifically for SO_2 control has typical SO_2 removal efficiencies of 25 to 50%, and typical HCl and HF control efficiencies of 80 – 90% or even higher, depending on the sorbent injection rate.

The coal-fired boilers at both the River Rouge and Trenton Channel Power Plants will be subject to the National Emission Standards for Hazardous Air Pollutants (NESHAP) From Coal and Oil-Fired Electric Utility Steam Generating Units, 40 CFR Part 63, Subpart UUUUU, published in the Federal Register on February 16, 2012. This subpart established Mercury and Air Toxics Standards (MATS) for coal and oil-fired electric utility steam generating units. Under 40 CFR § 63.10042, *Electric utility steam generating unit* (EGU) means a fossil fuel-fired combustion unit of more than 25 megawatts electric (MWe) that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is considered an electric utility steam generating unit. These standards include emission limits for:

a. Filterable particulate matter or limits on individual HAP metals,
b. Hydrogen chloride (HCl) or, for FGD controlled units, limits on SO_2 emissions, and
c. Mercury.

The use of sorbent injection may be used to comply with these MATS standards at both River Rouge and Trenton Channel. To achieve the MATS limit of 0.002 lb/mmBtu and an uncontrolled HCl emission rate of 0.004 to 0.03 lb/mmBtu (depending on the coal actually fired), the HCl reduction would need to be from 50% to approximately 95%. The sorbent injection required to achieve this HCl reduction is expected to achieve a 5% to 20% reduction in SO_2 emissions, depending on the coal fired and HCl reduction required.

From the Code of Federal Regulations

TABLE 2 TO SUBPART UUUUU OF PART 63 — EMISSION LIMITS FOR EXISTING EGUs

[As stated in § 63.9991, you must comply with the following applicable emission limits]

If your EGU is in this subcategory ...	For the following pollutants ...	You must meet the following emission limits and work practice standards ...
Coal-fired unit not low rank virgin coal (> 8,300 Btu/lb)	a. Filterable particulate matter (PM)	0.03 lb/MMBtu or 0.3 lb/MWh
	OR	OR
	Total non-Hg HAP metals	5.0E-5 lb/MMBtu or 5.0E-1 lb/GWh
	OR	OR
	Individual HAP metals:	
	Antimony (Sb)	0.8 lb/TBtu or 0.008 lb/GWh
	Arsenic (As)	1.1 lb/TBtu or 0.020 lb/GWh
	Beryllium (Be)	0.2 lb/TBtu or 0.002 lb/GWh
	Cadmium (Cd)	0.3 lb/TBtu or 0.003 lb/GWh
	Chromium (Cr)	2.8 lb/TBtu or 0.030 lb/GWh
	Cobalt (Co)	0.8 lb/TBtu or 0.008 lb/GWh
	Lead (Pb)	1.2 lb/TBtu or 0.020 lb/GWh
	Manganese (Mn)	4.0 lb/TBtu or 0.050 lb/GWh
	Nickel (Ni)	3.5 lb/TBtu or 0.040 lb/GWh
	Selenium (Se)	5.0 lb/TBtu or 0.060 lb/GWh
	b. Hydrogen chloride (HCl)	0.002 lb/MMBtu or 0.02 lb/MWh
	OR	OR
	Sulfur dioxide (SO_2)	0.2 lb/MMBtu or 1.5 lb/MWh
	c. Mercury (Hg)	1.2 lb/TBtu or 1.3E-2 lb/GWh

5.6.1 Technical Feasibility.

Dry sorbent injection into the ductwork is a technically feasible control option for the affected boilers at the River Rouge and Trenton Channel Power Plants.

Chapter 6. Ranking of the Technically Feasible SO_2 Control Technologies.

6.1 Wet Flue Gas Desulfurization.

Modern wet FGD designs can be designed to achieve 98 - 99% SO_2 removal on an initial performance guarantee basis. However, while modern wet FGD systems can be designed to achieve 98 - 99% SO_2 removal on an initial performance guarantee basis when firing high sulfur eastern bituminous coals, it is not technically feasible to achieve this high level of control on a continuous basis.

Based on the performance for existing coal-fired units using wet FGD systems, including DTE Energy's Monroe Power Plant, we have concluded that the use of wet FGD on the River Rouge and Trenton Channel coal-fired boilers could achieve SO_2 emission rates of 0.08 lb/mmBtu based on a 24-hour or daily basis, and 0.06 lb/mmBtu, based on a 12-month rolling average. This long term emission rate represents an average SO_2 emission reduction of 92.5% from the low sulfur subbituminous coal uncontrolled emission rate, and 95% reduction from the low sulfur bituminous/low sulfur subbituminous coal blend for Trenton Unit 9.

6.2 Dry Flue Gas Desulfurization.

Modern dry FGD spray dryer designs can achieve 90 - 95% SO_2 removal on an initial performance guarantee basis. Based on the performance for existing subbituminous coal-fired units using dry FGD systems, we have concluded that the use of dry FGD on the River Rouge and Trenton Channel Power Plant coal-fired boilers could achieve SO_2 emission rates of 0.12 lb/mmBtu based on a 24-hour basis, and 0.08 lb/mmBtu, based on a 12-month rolling average. This long term emission rate represents an average SO_2 emission reduction of 90% from the low sulfur subbituminous coal uncontrolled emission rate, and 93.3% reduction from the low sulfur bituminous/low sulfur subbituminous coal blend for Trenton Unit 9.

6.3 Sorbent Injection.

Sorbent injection systems are expected to achieve an SO_2 control efficiency of 10% to as much as 50%, depending on the injection rate. In this control ranking, we have identified two control levels for sorbent injection. The first sorbent injection control level is based on a sorbent injection system designed and optimized for SO_2 control. This control technology would have a high sorbent injection rate which would be required to achieve a 40% reduction in the SO_2 emission rate from the uncontrolled coal emission rate. For the low sulfur subbituminous coal, this would result in a controlled SO_2 emission rate of 0.48 lb/mmBtu. For the low sulfur bituminous/low sulfur subbituminous coal blend for Trenton Unit 9, this would result in a controlled SO_2 emission rate of 0.72 lb/mmBtu.

The second control level is based on the sorbent injection rate which is necessary to achieve the applicable Mercury and Air Toxics Standards (MATS) for coal-fired electric utility steam generating units 40 CFR Part 63, Subpart UUUUU. Low sulfur subbituminous coal has an uncontrolled HCl emission rate of approximately 0.004 to 0.010 lb/mmBtu. The low sulfur bituminous coals have a typical HCl emission rate of approximately 0.10 lb/mmBtu. Based on an 80% subbituminous/20% low sulfur bituminous coal blend, the coal blend would have an uncontrolled HCl emission rate of approximately 0.02 to 0.03 lb/mmBtu. To achieve the MATS limit of 0.002 lb/mmBtu, the HCl reduction would need to be from 50% to 80% for subbituminous coals, and 90% to 95% for the coal blend. This level of sorbent injection is expected to achieve a 5 - 10% reduction from the uncontrolled coal emission rate for subbituminous coal, and a 10 to 20% SO_2 reduction for the coal blend[2]. The use of sorbent injection for MATS compliance would utilize less sorbent than the sorbent injection system designed and optimized for SO_2 control, and it may utilize a different sorbent which is optimized for HCl removal.

For the low sulfur subbituminous coal, the residual SO_2 reduction achieved through the use of sorbent injection for HCl control would result in a controlled SO_2 emission rate of less than 0.72 lb/mmBtu on a 12-month basis. For the low sulfur bituminous/low sulfur subbituminous coal blend for Trenton Unit 9, the residual SO_2 reduction achieved through the use of sorbent injection for HCl control would result in a controlled SO_2 emission rate of 1.02 lb/mmBtu on a 12-month basis.

6.4 Low Sulfur Coal.

6.4.1 Low Sulfur Western Subbituminous Coals.

The lowest SO_2 emitting coals which are commercially available for the River Rouge and Trenton Channel Power Plants is low sulfur western subbituminous (Powder River Basin or PRB) coals. PRB coals have heat values in the range of 8,200 to 9,400 Btu per pound, and sulfur contents in the range of 0.3 to 0.7%. The current commercially available PRB coals have typical uncontrolled SO_2 emission rates ranging from 0.5 to more than 1.6 lb/mmBtu. According to the document *Coal Quality and Major, Minor, and Trace Elements in the Powder River, Green River, and Williston Basins, Wyoming and North Dakota*, Open-File Report 2007-1116, U.S. Department of the Interior, U.S. Geological Survey, Table 3, all PRB samples have a mean sulfur content of 0.29%, with a standard deviation of 0.35%, and a mean heating value of 9,250 mmBtu per pound. Based on these analyses, PRB coals have a mean potential SO_2 combustion concentration of 0.63 lb/mmBtu, with a 2 standard deviation high of 2.1 lb/mmBtu. For this analysis, these low sulfur coals are expected to achieve SO_2 emission rates which are less than 0.8 lb/mmBtu on an annual basis, and less than 1.3 lb/mmBtu on a daily basis. However, because of the natural variability of sulfur in coal, the short term achievable emission rate for each boiler is actually the ***mass*** emission rate for the boiler, expressed in tons per day.

6.4.2 Low Sulfur Eastern Bituminous Coals.

Low sulfur eastern bituminous coals are also commercially available. The U.S. Department of Energy's Energy Information Administration provides data for coal reserves in the following sulfur content ranges:

[2] From *Combined Treatment of HCl and SO_2: Independent Study Shows Selectivity and Effectiveness of Sodium Dry Sorbent Injection*, Y. Kong, M. Wood, Solvay Chemicals, Inc. From Figure 6, for HCl control efficiencies of 50 - 80%, SO_2 control efficiency range from 5 - 15%. At a 90% reduction, SO_2 removal may range from 10 - 20%.

U.S. DOE coal reserve categories of sulfur content in coal

Category	Sulfur Content, lb S/mmBtu	SO2 Emission Rate, lb SO_2/mmBtu
Low Sulfur	≤ 0.60	≤ 1.20
Medium	0.61 – 1.67	1.21 – 3.34
High Sulfur	≥ 1.68	≥ 3.36

Most of the high Btu, low sulfur bituminous coals are from the Appalachian region. However, these coals represent less than 6% of US coal reserves[3].

6.4.3 Low Sulfur Subbituminous / Bituminous Coal Blends.

The River Rouge and Trenton Channel Power Plants currently burn a blend of low sulfur subbituminous and bituminous coals. A blend of bituminous and subbituminous coals is used because subbituminous coals have a lower heating value than the design eastern bituminous coals for the River Rouge and Trenton Channel boilers. As a result, the use of only low sulfur subbituminous coals can reduce the total heat input to the boilers which also reduces the steam output from the boilers and thereby "derates" or reduces the net electric output of the units. This unit derating is of particular concern for the River Rouge Unit 3 and Trenton Channel Unit 9. To minimize SO_2 emissions but maintain the maximum electric output of the units, the River Rouge and Trenton Channel Power Plants currently burn a blend of low sulfur subbituminous coal with a low sulfur eastern bituminous coal. When optimized for SO_2 reductions, this blend of low sulfur coals is expected to have an SO_2 emission rate which is less than 1.2 lb/mmBtu on an annual basis, and less than 1.5 lb/mmBtu on a daily basis.

For much of the operating time, the derating of the River Rouge Unit 3 and Trenton Channel Unit 9 are not a serious concern, since a small reduction in electric output can be economically replaced by other available electric generating units in the region. However, during periods of peak electric demand, this derating can have a significant impact to electric generation costs.

[3] *U.S. Coal Reserves: An Update by Heat and Sulfur Content*, February 1993, DOE/EIA-0529(92), Energy Information Administration, Table ES1 Estimates of the Demonstrated Reserve Base of Coal in the United States by Btu/Sulfur Ranges and Regions.

6.5 Ranking of the Technically Feasible Control Options.

Table 7 is a summary of the ranking of the technically feasible SO_2 control technologies for the River Rouge Unit 2 and the Trenton Channel High Side Boilers 16, 17, 18, and 19 based on the above analysis of available technologies. For the River Rouge Unit 2 and Trenton Channel High Side Boilers 16 – 19, the long term uncontrolled SO_2 emission rate for all options is based on the use of only low sulfur subbituminous coals. That is, the reduction of SO_2 emissions for post combustion control systems is based on the reduction from the uncontrolled subbituminous coal emission rate.

Table 8 is a summary of the ranking of the technically feasible SO_2 control technologies for the River Rouge Unit 3 and the Trenton Channel Unit 9 based on the above analysis. Because these units may be significantly derated through the use of only low sulfur subbituminous coals, the long term uncontrolled SO_2 emission rate for all options is based on the use of a blend of low sulfur western subbituminous coals and low sulfur eastern bituminous coals which is expected to have a long term SO_2 emission rate of 1.2 lb/mmBtu, and a maximum daily SO_2 emission rate of up to 1.5 lb/mmBtu.

6.5.1 Achievable Short Term Emission Rates.

In Tables 7 and 8, the achievable short term SO_2 emission rate expressed on a 24-hour or daily basis is stated on a pound per million Btu (lb/mmBtu) basis. However, because of the natural variability of sulfur in coal, an unexpected coal shipment with an elevated sulfur content could result in emissions above the achievable emission rate when expressed on a lb/mmBtu basis, even if the mass emission rate of SO_2 emissions is relatively small. Since it is the mass of SO_2 emissions which can cause high ambient air concentrations, the short term achievable emission rate for each boiler is the ***mass*** emission rate for the boiler, expressed in tons per day. For example, for the River Rouge Unit 2, the short term achievable emission rate for subbituminous coal combustion is:

Achievable Emission Rate = (2,280 mmBtu/hr)(1.3 lb SO_2/mmBtu)(24 hr/day)(ton/2,000 lb)

Achievable Emission Rate = 35.57 tons SO_2/day

When the achievable emission rate is expressed in tons per day, plant management can reduce load or take other actions to limit SO_2 mass emissions to meet the achievable emission rates. These emission limits are consistent with the current SO_2 emission limits for these power plants. Further, because these units are equipped with SO_2 continuous emissions monitoring systems (SO_2 CEMS) which measure SO_2 mass emissions for each hour of operation in accordance with the federal Acid Rain Program in 40 CFR Part 75, demonstrating compliance with a mass emission limit is straightforward and easy to accomplish in practice.

TABLE 7. Ranking of the technically feasible SO_2 control technologies for the River Rouge Unit 2 and the Trenton Channel High Side Boilers 16, 17, 18, and 19.

Control Technology	Expected Emission Rate, lb/mmBtu	
	24-hour Ave.	12-mo Ave.
1. Wet Flue Gas Desulfurization (wet FGD).	0.08	0.06
2. Dry Flue Gas Desulfurization (dry FGD).	0.12	0.08
3. Sorbent Injection (Optimized for SO_2 control).	0.78	0.48
4. Sorbent Injection (MATS Compliance) and Subbit coal.	1.17	0.72
5. Low Sulfur Subbituminous Coal.	1.3	0.8
6. Bituminous/Low Sulfur Subbituminous Coal Blend.	1.5	1.2

Footnotes

Because of the natural variability of sulfur in coal, the short term achievable emission rate for each boiler is the ***mass*** emission rate for the boiler, expressed in tons per day.

TABLE 8. Ranking of the technically feasible SO_2 control technologies for the River Rouge Unit 3 and the Trenton Channel Unit 9.

Control Technology	Expected Emission Rate, lb/mmBtu	
	24-hour Ave.	12-mo Ave.
1. Wet Flue Gas Desulfurization (wet FGD).	0.08	0.06
2. Dry Flue Gas Desulfurization (dry FGD).	0.12	0.08
3. Sorbent Injection (Optimized for SO_2 control).	0.90	0.72
4. Sorbent Injection (MATS Compliance) and Coal Blend.	1.28	1.02
5. Low Sulfur Subbituminous Coal.	1.3	0.8
6. Bituminous/Low Sulfur Subbituminous Coal Blend.	1.5	1.2

Footnotes

Because of the natural variability of sulfur in coal, the short term achievable emission rate for each boiler is the ***mass*** emission rate for the boiler, expressed in tons per day.

Chapter 7. Evaluate the Most Effective Controls.

7.1 Rank No. 1: Wet Flue Gas Desulfurization.

7.1.1 Environmental and Energy Impacts.

The most effective post combustion SO_2 control option for the River Rouge and Trenton Channel Power Plants is the use of wet FGD systems. Based on the above analysis, a wet FGD system has the potential to reduce SO_2 emissions to 0.06 lb/mmBtu based on a 12-month rolling average, and to 0.08 lb/mmBtu based on a 24-hour or daily average. The use of wet FGD systems on these units is also expected to reduce other acid gases, including HCl emissions.

However, the use of wet FGD systems on the River Rouge and Trenton Channel Power Plants would have other adverse environmental effects. Wet FGD systems consume large amounts of water and create new wastewater discharge streams. Wet FGD systems create a significant waste stream of calcium sulfite or calcium sulfate which would likely require disposal. The use of wet FGD systems would require new stacks designed for saturated flue gas conditions, and the stack plume would have a distinct visual plume which may adversely impact the local urban areas. A wet FGD system will also require substantial auxiliary electric power requirements to operate slurry pumps, sludge dewatering, and for the induced draft fan requirements to overcome the wet FGD system pressure drop. This increased auxiliary power requirement reduces overall plant efficiency and would increase the emission rate of other pollutants when stated on an equivalent net electric output basis.

7.1.2 Economic Feasibility.

The costs for retrofitting wet FGD on the River Rouge and Trenton Channel Power Plants would include capital costs for the wet FGD system absorber tower and associated equipment, and other necessary equipment including new fiberglass lined stacks, limestone slurry production equipment, gypsum dewatering equipment, limestone and gypsum material handling systems, and a wastewater treatment facility. Wet FGD system operating costs would include labor, additional auxiliary power requirements, lime or limestone reagent, gypsum handling and disposal costs, maintenance costs, and administrative costs. Both the River Rouge and Trenton Channel Power Plants are located in urban areas and have constrained plant layouts and boundaries, so that the installation of this equipment would be very difficult at either site.

7.1.2.1 Average Cost Effectiveness.

In the EPA's New Source Review Manual, page B.37, average cost effectiveness is calculated as:

$$\text{Average Cost Effectiveness (\$ per ton removed)} = \frac{\text{Control option annualized cost}}{\text{Baseline emission rate – Control option emissions rate}}$$

For this economic analysis, the capital and operating (O&M) costs for the retrofitting op wet FGD systems on the River Rouge and Trenton Channel Power Plants has been estimated using the U.S. EPA's Coal Utility Environmental Cost (CUECOST) software, Version 1, revised as CUECOST3. Attachment 1 of this RACT analysis includes the CUECOST input and output data for this analysis. For the River Rouge Units 2 and 3 and for Trenton Channel Unit 9, the wet FGD costs are based on one absorber tower for each unit. For the Trenton Channel High Side Boilers 16, 17, 18, and 19, the wet FGD costs have been evaluated based on one wet FGD absorber tower which would serve all four boilers.

The average cost effectiveness is based on the overall reduction in the air pollutant from the baseline emission rate. ***For the River Rouge Unit 2 and Trenton Channel High Side Boilers 16 - 19, the baseline emission rate is the emission rate which can be achieved by utilizing 100% low sulfur subbituminous coal option (Option 5). For the River Rouge Unit 3 and Trenton Channel Unit 9, the baseline emission rate is the low sulfur subbituminous coal/low sulfur bituminous coal blend option (Option 6).***

The capital costs for new wet FGD systems at the River Rouge and Trenton Channel Power Plants would be $412 million and $452 million, respectively. The annual operating costs for wet FGD systems would include fixed and variable O&M costs, and capital recovery costs. Fixed O&M costs include costs such as labor and certain maintenance costs. Variable O&M costs include reagent costs, and maintenance costs which are related to plant utilization. As noted on page 15 of this RACT analysis, the capital recovery costs (the annual cost required to pay for the total project cost) ***are based on a project life of 7 years for all capital costs***. A 7 year project life is used because the River Rouge Units 2 and 3 were constructed in 1954 and 1955, the Trenton Channel Highside Boilers 16 – 19 were constructed in 1948 – 1949, and the Trenton Channel Boiler 9A was constructed in 1965. These electric generating units are therefore from 49 to 66 years old. The construction of post combustion wet and dry FGD systems would require at least 3 years to complete after project approval; the construction of sorbent injection systems will require at least 2 years to complete. Therefore, at the end of a 7-year project cost recovery period, these units would be from 58 to 75 years old. A longer project recovery period is simply not compatible with the age of these units.

It is also important to note that all of these units are expected to operate at levels well below 100% capacity factor (i.e., well below their maximum rated output for 8,760 hours per year). The maximum utilization of these units is expected to be approximately 55% for at least the next 4 – 5 years. Therefore, the cost effectiveness in this analysis are based on a maximum expected utilization of each unit equal to 55% capacity factor. Tables 9, 10, 11, and 12 summarize the costs of the control options based on a utilization of 55% for each unit.

TABLE 9. SO_2 control technologies, achievable emission rates, costs, and cost effectiveness for the River Rouge Unit 2.

Control Option	Achievable SO_2 Emission Rate[1,2]		Emission Reduction[3], ton/year		Capital Cost[4]	Total Annual Cost	Cost Effectiveness
	lb/mmBtu	ton/year	From Low Sulfur Coal	From Current Allowable		$/year	$ per ton
1. Wet Flue Gas Desulfurization (wet FGD).	0.06	330	4,064	15,438	$195,555,000	$47,189,400	$11,610
2. Dry Flue Gas Desulfurization (dry FGD).	0.08	439	3,955	15,329	$215,627,000	$52,431,200	$13,260
3. Sorbent Injection (optimized for SO_2 control).	0.48	2,636	1,758	13,132	$11,680,000	$19,292,600	$10,980
4. Sorbent Injection (for MATS Compliance).	0.72	3,955	439	11,813	$11,680,000	$13,635,300	$31,030
5. Low Sulfur Subbituminous Coal.	0.8	4,394	0	11,374			
6. Low Sulfur Bituminous / Low Sulfur Subbituminous Coal Blend.	1.2	6,591	0	9,177			
Current Allowable Emissions	**1.67**	**15,768**					

Footnotes

1. The achievable emission rate is based on a 12-month rolling average. The emission rate in tons per year is also based on a capacity factor of 55%.
2. The achievable annual emissions for RR2 are based on a boiler rating of 2,280 mmBtu per hour, and a capacity factor of 55%.
3. The emission reduction for determining cost effectiveness is from the Low Sulfur Subbituminous Coal (Option 5).
4. The capital and annual costs are detailed in Attachment 1.
5. Because the River Rouge Unit 2 is currently 60 years old, the capital recovery costs are based on a project life of 7 years and are detailed in Attachment 1.

TABLE 10. SO_2 control technologies, achievable emission rates, costs, and cost effectiveness for the River Rouge Unit 3.

Control Option	Achievable SO_2 Emission Rate[1,2]		Emission Reduction[3], ton/year		Capital Cost[4]	Total Annual Cost	Cost Effectiveness
	lb/mmBtu	ton/year	From Coal Blend	From Current Allowable		$/year	$ per ton
1. Wet Flue Gas Desulfurization (wet FGD).	0.06	386	7,333	18,046	$217,194,000	$52,991,600	$7,230
2. Dry Flue Gas Desulfurization (dry FGD).	0.08	515	7,204	17,917	$247,673,000	$60,942,300	$8,460
3. Sorbent Injection (optimized for SO_2 control).	0.72	4,631	3,087	13,801	$15,400,000	$25,437,100	$8,240
4. Sorbent Injection (for MATS Compliance).	1.02	6,561	1,158	11,871	$15,400,000	$17,978,000	$15,530
5. Low Sulfur Subbituminous Coal.	0.8	5,146	1,048	13,286	-	$2,066,700 to $2,347,500	$1,970 to $2,240
6. Low Sulfur Bituminous / Low Sulfur Subbituminous Coal Blend.	1.2	7,718	0	10,714			
Current Allowable Emissions	**1.67**	**18,432**					

Footnotes

1. The achievable emission rate is based on a 12-month rolling average. The emission rate in tons per year is also based on a capacity factor of 55%.
2. The achievable annual emissions for RR3 are based on a boiler rating of 2,670 mmBtu per hour, and a capacity factor of 55%.
3. The emission reduction for determining cost effectiveness is from the Low Sulfur Bituminous / Low Sulfur Subbituminous Coal Blend.
4. The capital and annual costs are detailed in Attachment 1.
5. Because the River Rouge Unit 3 is currently 59 years old, the capital recovery costs are based on a project life of 7 years and are detailed in Attachment 1.

TABLE 11. SO_2 control technologies, achievable emission rates, costs, and cost effectiveness for the Trenton Channel High Side Boilers 16, 17, 18, and 19.

Control Option	Achievable SO_2 Emission Rate[1, 2]		Emission Reduction[3], ton/year		Capital Cost[4]	Total Annual Cost	Cost Effectiveness
	lb/mmBtu	ton/year	From Low Sulfur Coal	From Current Allowable		$/year	$ per ton
1. Wet Flue Gas Desulfurization (wet FGD).	0.06	437	5,389	21,675	$195,482,000	$46,858,900	$8,700
2. Dry Flue Gas Desulfurization (dry FGD).	0.08	583	5,243	21,529	$215,633,000	$52,379,600	$9,990
3. Sorbent Injection (optimized for SO_2 control).	0.48	3,496	2,330	18,616	$14,400,000	$16,810,700	$7,210
4. Sorbent Injection (for MATS Compliance).	0.72	5,243	583	16,869	$14,400,000	$12,160,800	$20,870
5. Low Sulfur Subbituminous Coal.	0.8	5,826	0	16,286			
6. Low Sulfur Bituminous / Low Sulfur Subbituminous Coal Blend.	1.2	8,739	0	13,373			
Current Allowable Emissions	**1.67**	**22,112**					

Footnotes

1. The achievable emission rate is based on a 12-month rolling average. The emission rate in tons per year is also based on a capacity factor of 55%.
2. The achievable annual emissions for the TC High Side boilers are based on a total boiler rating of 3,023 mmBtu per hour, and a capacity factor of 55%.
3. The emission reduction for determining cost effectiveness is from the Low Sulfur Subbituminous Coal (Option 5).
4. The capital and annual costs are detailed in Attachment 1.
5. Because the TC High Side boilers are currently at least 65 years old, the capital recovery costs are based on a project life of 7 years and are detailed in Attachment 1.

TABLE 12. SO_2 control technologies, achievable emission rates, costs, and cost effectiveness for the Trenton Channel Unit 9.

Control Option	Achievable SO_2 Emission Rate[1, 2]		Emission Reduction[3], ton/year		Capital Cost[4]	Total Annual Cost	Cost Effectiveness
	lb/mmBtu	ton/year	From Coal Blend	From Current Allowable		$/year	$ per ton
1. Wet Flue Gas Desulfurization (wet FGD).	0.06	655	12,441	32,480	$257,000,000	$63,169,600	$5,080
2. Dry Flue Gas Desulfurization (dry FGD).	0.08	873	12,222	32,262	$312,372,000	$73,633,700	$6,020
3. Sorbent Injection (optimized for SO_2 control).	0.72	7,857	5,238	25,278	$21,400,000	$35,347,800	$6,750
4. Sorbent Injection (for MATS Compliance).	1.02	11,131	1,964	22,004	$21,400,000	$24,982,500	$12,720
5. Low Sulfur Subbituminous Coal.	0.8	8,730	558	24,405	-	$2,122,400 to $2,824,500	$3,800 to $5,060
6. Low Sulfur Bituminous / Low Sulfur Subbituminous Coal Blend.	1.2	13,095	0	20,040			
Current Allowable Emissions	**1.67**	**33,135**					

Footnotes

6. The achievable emission rate is based on a 12-month rolling average. The emission rate in tons per year is also based on a capacity factor of 55%.
7. The achievable annual emissions for TC9 are based on a boiler rating of 4,530 mmBtu per hour, and a capacity factor of 55%.
8. The emission reduction for determining cost effectiveness is from the Low Sulfur Bituminous / Low Sulfur Subbituminous Coal Blend.
9. The capital and annual costs are detailed in Attachment 1.
1. Because the TC Unit 3 is currently 49 years old, the capital recovery costs are based on a project life of 7 years and are detailed in Attachment 1.

Table 13 is a summary of the cost analysis for wet FGD for the River Rouge and Trenton Channel Power Plants. The cost effectiveness based on a maximum expected utilization of 55% for each unit and a project cost recovery period of 7 years range from $5,080 per ton for Trenton Channel Unit 9, to $11,610 per ton for River Rouge Unit 2.

TABLE 13. Summary of the cost effectiveness for the use of wet flue gas desulfurization.

Unit	Emission Reduction ton/year	Capital Cost	Total Annual Cost $/year	Cost Effectiveness $ per ton
River Rouge Unit 2	4,064	$195,555,000	$47,189,400	$11,610
River Rouge Unit 3	7,333	$217,194,000	$52,991,600	$7,230
Trenton Channel Boilers 16, 17, 18, and 19	5,389	$195,482,000	$46,858,900	$8,700
Trenton Channel Unit 9	12,441	$257,000,000	$63,169,600	$5,080

7.1.3 Conclusions.

Wet FGD systems are the most effective post combustion SO_2 control option for the River Rouge and Trenton Channel Power Plants. Based on the above analysis, a wet FGD system has the potential to reduce SO_2 emissions by 92.5 to 95%, and the use of wet FGD systems would also reduce other acid gases, including HCl emissions. However, the costs for the use of wet FGD systems on the River Rouge and Trenton Channel Power Plants range from $5,080 to $11,610 per ton of SO_2 controlled based on the expected normal utilization of these units of 55%. Based on these high costs, the use of wet FGD systems for the control of SO_2 emissions is not a reasonable available control technology for the affected coal-fired electric generating units.

7.2 Rank No. 2: Dry Flue Gas Desulfurization.

7.2.1 Environmental and Energy Impacts.

Based on the above analysis, the use of dry FGD systems on the existing River Rouge and Trenton Channel Power Plants has the potential to reduce SO_2 emissions to 0.08 lb/mmBtu based on a 12-month rolling average, and to 0.12 lb/mmBtu based on a 24-hour or daily average. Like wet FGD systems, the use of dry or semi-dry FGD systems on these units is also expected to reduce other acid gases, including HCl emissions.

However, as with wet FGD systems, the use of dry FGD systems on the River Rouge and Trenton Channel Power Plants would have other adverse environmental effects. Dry and semi-dry FGD systems also consume large amounts of water and also require substantial auxiliary electric power requirements to operate reagent slurry pumps and for the induced draft fan requirements to overcome the dry FGD system pressure drop. This increased auxiliary power requirement would reduce overall plant efficiency and would increase the emission rate of other pollutants when stated on an equivalent net electric output basis. Dry FGD systems will also create a large waste stream which will require landfill disposal.

7.2.2 Economic Feasibility.

The costs for retrofitting dry FGD on the River Rouge and Trenton Channel Power Plants would include capital costs for the dry FGD system absorber tower and associated equipment, and other necessary equipment. It is important to note that dry FGD systems are normally operated with fabric filter baghouse air quality control systems. The use of fabric filter baghouses improves SO_2 control efficiency since much of the SO_2 removal occurs in the filter cake of the baghouse. In addition, these units may not be able to comply with the applicable PM emission limits without the addition of new fabric filter baghouses if dry or semi-dry FGD systems were installed on these units. In this analysis, new fabric filter baghouses increased the total capital cost for dry FGD systems by $60 to $110 million per dry FGD system.

For this economic analysis, the capital and operating (O&M) costs for the retrofitting of wet FGD systems on the River Rouge and Trenton Channel Power Plants has been estimated using the U.S. EPA's Coal Utility Environmental Cost (CUECOST) software, Version 1, revised as CUECOST3. Attachment 1 of this RACT analysis includes the CUECOST input and output data for this analysis. In this analysis, the costs are based on the use of dry FGD Lime Spray Dry (LSD) systems. For the River Rouge Units 2 and 3 and for Trenton Channel Unit 9, the dry FGD costs are based on one absorber tower for each unit. For the Trenton Channel High Side Boilers 16, 17, 18, and 19, the dry FGD costs have been evaluated based on one wet FGD absorber tower which would serve all four boilers. In addition, the costs for new fabric filter baghouses have also been included in this analysis.

The average cost effectiveness is based on the overall reduction in the air pollutant from the baseline emission rate. For the River Rouge Unit 2 and Trenton Channel High Side Boilers 16 - 19, the baseline emission rate is the 100% low sulfur subbituminous coal option (Option 5). For the River Rouge Unit 3 and Trenton Channel Unit 9, the baseline emission rate is the low sulfur subbituminous coal/low sulfur bituminous coal blend option (Option 6). The capital costs for new dry or semi-dry FGD systems at the River Rouge and Trenton Channel Power Plants would be $463 million and $528 million, respectively.

The annual operating costs for dry or semi-dry FGD systems would include fixed and variable O&M costs, and capital recovery costs. Fixed O&M costs include costs such as labor and certain maintenance costs. Variable O&M costs include reagent costs, and maintenance costs which are related to plant utilization. As noted on page 15 of this RACT analysis, the capital recovery costs (the annual cost required to pay for the total project cost) ***are based on a project life of 7 years for all capital costs***.

In addition, because these units are expected to operate at levels well below 100% capacity factor (i.e., well below their maximum rated output for 8,760 hours per year), the maximum utilization of these units is expected to be approximately 55% for at least the next 4 – 5 years. Therefore, the cost effectiveness in this analysis is based on a maximum expected utilization of each unit equal to 55% capacity factor.

Table 14 is a summary of the cost analysis for dry or semi-dry FGD for the River Rouge and Trenton Channel Power Plants. The cost effectiveness based on a maximum expected utilization of 55% for each unit and a project cost recovery period of 7 years range from $6,020 per ton for Trenton Channel Unit 9, to $13,260 per ton for River Rouge Unit 2.

TABLE 14. Summary of the cost effectiveness for the use of dry flue gas desulfurization.

Unit	Emission Reduction	Capital Cost	Total Annual Cost	Cost Effectiveness
	ton/year		$/year	$ per ton
River Rouge Unit 2	3,955	$215,627,000	$52,431,200	$13,260
River Rouge Unit 3	7,204	$247,673,000	$60,942,300	$8,460
Trenton Channel Boilers 16, 17, 18, and 19	5,243	$215,633,000	$52,379,600	$9,990
Trenton Channel Unit 9	12,222	$312,372,000	$73,633,700	$6,020

7.2.3 Conclusions.

Dry or semi-dry FGD systems are the second most effective post combustion SO_2 control option for the River Rouge and Trenton Channel Power Plants. Based on the above analysis, a dry FGD system has the potential to reduce SO_2 emissions by 90 to 93.3%, and the use of dry FGD systems would also reduce other acid gases, including HCl emissions. However, the costs for the use of dry FGD systems on the River Rouge and Trenton Channel Power Plants range from $6,020 to $13,260 per ton of SO_2 controlled based on the expected normal utilization of these units of 55%. Based on these high costs, the use of dry or semi-dry FGD systems for the control of SO_2 emissions is not a reasonable available control technology for the affected coal-fired electric generating units.

7.3 Rank No. 3: Sorbent Injection Optimized for SO_2 Control.

7.3.1 Environmental and Energy Impacts.

Based on the above analysis, the use of dry sorbent injection systems designed to optimize SO_2 removal on the existing River Rouge Unit 2 and the Trenton Channel High Side Boilers 16 to 19 has the potential to reduce SO_2 emissions to 0.48 lb/mmBtu based on a 12-month rolling average, and to 0.72 lb/mmBtu based on a 24-hour or daily average. This reduction represents a 40% reduction from the low sulfur subbituminous coal (Option 5). For the River Rouge Unit 3 and the Trenton Channel Unit 9, the use of dry sorbent injection systems designed to optimize SO_2 removal has the potential to reduce SO_2 emissions to 0.72 lb/mmBtu based on a 12-month rolling average, and to 0.90 lb/mmBtu based on a 24-hour or daily average. This reduction represents a 40% reduction from the low sulfur subbituminous coal/low sulfur bituminous coal blend (Option 6).

Like the other FGD systems, the use of sorbent injection on these units is also expected to reduce other acid gases, including HCl emissions. The use of sorbent injection designed to optimize SO_2 removal will also create a significant increase of material requiring landfill disposal.

7.3.2 Economic Feasibility.

The costs for the use of dry sorbent injection air quality control systems on the River Rouge and Trenton Channel Power Plants are substantially less than those for wet and dry or semi-dry FGD systems, and include primarily the sorbent injection equipment, storage silo(s), and other ancillary equipment.

For this economic analysis, the capital and operating (O&M) costs for the installation and operation of dry sorbent injection air quality control systems on the River Rouge and Trenton Channel Power Plants has been estimated based on the report *IPM Model – Revisions to Cost and Performance for APC Technologies, Dry Sorbent Injection Cost Development Methodology*, *FINAL*, August 2010, Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy. This analysis was prepared to update the U.S. EPA's economic analysis of sorbent injection costs. These costs include a total project (capital cost) of $40 per kW of installed electric generating capacity, a fixed O&M cost of $0.59 per kW of capacity, and a variable O&M cost of $7.92 per MWhr of electric generation. When optimized for SO2 reductions, the variable O&M costs for the operation of the sorbent injection system have been estimated to be 50% higher than the costs for MATS compliance. A sorbent injection system using high sorbent injection rates for optimized SO_2 removal would likely require the addition of fabric filter systems to meet MATS particulate matter emission limits. Fabric filter baghouse systems would increase capital cost by $60 million to $110 million per unit. However, the costs for new fabric filter baghouses have NOT been included in this analysis.

The average cost effectiveness is based on the overall reduction in the air pollutant from the baseline emission rate. For the River Rouge Unit 2 and Trenton Channel High Side Boilers 16 - 19, the baseline emission rate is the 100% low sulfur subbituminous coal option (Option 5). For the River Rouge Unit 3 and Trenton Channel Unit 9, the baseline emission rate is the low sulfur subbituminous coal/low sulfur bituminous coal blend option (Option 6).

From Tables 9, 10, 11, and 12, the capital costs for sorbent injection systems at the River Rouge and Trenton Channel Power Plants would be $27 million and $36 million, respectively. These capital costs are much less than the capital costs for wet and dry FGD systems, and reflect the primary advantage of sorbent injection – low capital costs. However, the annual operating costs at 55% capacity factor for sorbent injection systems at the River Rouge and Trenton Channel Power Plants would be $45 and $52 million, respectively which reflects the primary disadvantage of sorbent injection – high operating costs. The cost effectiveness, again based on 55% utilization, range from $6,750 per ton of SO_2 controlled for Trenton Channel Unit 9, to $10,980 per ton for River Rouge Unit 2.

Table 15 is a summary of the cost analysis for the use of sorbent injection systems optimized for SO_2 control for the River Rouge and Trenton Channel Power Plants. Note that if fabric filter baghouses would be required for particulate matter control at high sorbent injection rates, this change would significantly increase the capital cost requirements for sorbent injection.

TABLE 15. Summary of the cost effectiveness for the use of dry sorbent injection optimized for SO_2 control.

Unit	Emission Reduction	Capital Cost	Total Annual Cost	Cost Effectiveness
	ton/year		$/year	$ per ton
River Rouge Unit 2	1,758	$11,680,000	$19,292,600	$10,980
River Rouge Unit 3	3,087	$15,400,000	$25,437,100	$8,240
Trenton Channel Boilers 16, 17, 18, and 19	2,330	$14,400,000	$16,810,700	$7,210
Trenton Channel Unit 9	5,238	$21,400,000	$35,347,800	$6,750

7.3.3 Conclusions.

Based on the above analysis, the use of dry sorbent injection systems designed to optimize SO_2 removal has the potential to reduce SO_2 emissions by 40% from the uncontrolled emission rate. Like the other FGD systems, the use of sorbent injection on these units is also expected to reduce other acid gases, including HCl emissions. However, the costs for the use of dry sorbent injection systems designed to optimize SO_2 removal on the River Rouge and Trenton Channel Power Plants range from $6,750 to $10,980 per ton of SO_2 controlled based on the expected normal utilization of these units of 55%. Based on these high costs, the use of dry sorbent injection systems designed to optimize SO_2 removal for the control of SO_2 emissions is not a reasonable available control technology for the affected coal-fired electric generating units.

7.4 Rank No. 4: Sorbent Injection for MATS Compliance.

7.4.1 Environmental and Energy Impacts.

Based on the above analysis, the use of dry sorbent injection systems designed and utilized for MATS Compliance on the existing River Rouge Unit 2 and the Trenton Channel High Side Boilers 16 to 19 has the potential to reduce SO_2 emissions to 0.72 lb/mmBtu based on a 12-month rolling average, and to 1.08 lb/mmBtu based on a 24-hour or daily average. This reduction represents a 10% reduction from the low sulfur subbituminous coal (Option 5). For the River Rouge Unit 3 and the Trenton Channel Unit 9, the use of dry sorbent injection systems designed to optimize SO_2 removal has the potential to reduce SO_2 emissions to 1.02 lb/mmBtu based on a 12-month rolling average, and to 1.28 lb/mmBtu based on a 24-hour or daily average. This reduction represents a 15% reduction from the low sulfur subbituminous coal/low sulfur bituminous coal blend (Option 6).

Like the other FGD systems, the use of sorbent injection on these units is also expected to reduce other acid gases, including HCl emissions. The use of sorbent injection designed to optimize SO_2 removal will also create a significant increase of material requiring landfill disposal.

Based on the above analysis, the use of dry sorbent injection systems designed for MATS compliance on the existing River Rouge and Trenton Channel Power Plants has the potential to reduce SO_2 emissions to 0.72 lb/mmBtu based on a 12-month rolling average, and to 1.10 lb/mmBtu based on a 24-hour or daily average. The use of sorbent injection on these units would be installed to reduce HCl emissions to comply with the utility boiler MATS requirements.

7.4.2 Economic Feasibility.

As noted in the previous section, the costs for the use of dry sorbent injection air quality control systems on the River Rouge and Trenton Channel Power Plants are substantially less than those for wet and dry or semi-dry FGD systems, and include primarily the sorbent injection equipment, storage silo(s), and other ancillary equipment. For this economic analysis, the capital and operating (O&M) costs for the installation and operation of dry sorbent injection air quality control systems on the River Rouge and Trenton Channel Power Plants has been estimated based on the report *IPM Model – Revisions to Cost and Performance for APC Technologies, Dry Sorbent Injection Cost Development Methodology, FINAL*, August 2010, Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy. This analysis was prepared to update the U.S. EPA's economic analysis of sorbent injection costs. These costs include a total project (capital cost) of $40 per kW of installed electric generating capacity, a fixed O&M cost of $0.59 per kW of capacity, and a variable O&M cost of $7.92 per MWhr of electric generation.

As with the analysis for wet and dry FGD systems, the average cost effectiveness is based on the overall reduction in the air pollutant from the baseline emission rate. For the River Rouge Unit 2 and Trenton Channel High Side Boilers 16 - 19, the baseline emission rate is the 100% low sulfur subbituminous coal option (Option 5). For the River Rouge Unit 3 and Trenton Channel Unit 9, the baseline emission rate is the low sulfur subbituminous coal/low sulfur bituminous coal blend option (Option 6).

Table 16 is a summary of the cost analysis for the use of sorbent injection systems designed and operated for MATS compliance for the River Rouge and Trenton Channel Power Plants. Note that the cost effectiveness of sorbent injection is much less dependent on the utilization of the unit, since most of the annual cost of sorbent injection is due to variable O&M (i.e., sorbent) costs, while for wet and dry FGD, much of the cost is the cost of capital for the installation of controls.

TABLE 16. Summary of the cost effectiveness for the use of dry sorbent injection for MATS compliance.

Unit	Emission Reduction ton/year	Capital Cost	Total Annual Cost $/year	Cost Effectiveness $ per ton
River Rouge Unit 2	439	$11,680,000	$13,635,300	$31,030
River Rouge Unit 3	1,158	$15,400,000	$17,978,000	$15,530
Trenton Channel Boilers 16, 17, 18, and 19	583	$14,400,000	$12,160,800	$20,870
Trenton Channel Unit 9	1,964	$21,400,000	$24,982,500	$12,720

7.4.3 Conclusions.

Based on the above analysis, the use of dry sorbent injection systems designed for MATS Compliance has the potential to reduce SO_2 emissions by 10% from the uncontrolled emission rate when burning 100% low sulfur subbituminous coals, and by 15% when burning a low sulfur subbituminous/low sulfur bituminous coal blend. This sorbent injection would be specifically designed to primarily reduce HCl emissions. However, the costs for the use of dry sorbent injection systems designed for MATS Compliance on the River Rouge and Trenton Channel Power Plants range from $12,720 to $31,030 per ton of SO_2 controlled based on the expected normal utilization of these units of 55%. Based on these high costs, the use of dry sorbent injection systems designed for MATS Compliance for the control of SO_2 emissions is not a reasonable available control technology for the affected coal-fired electric generating units.

7.5 Rank No. 5: Low Sulfur Subbituminous Coal.

7.5.1 Environmental and Energy Impacts.

Based on the above analysis, an emission limit equal to the rate which can be achieved by the use of only low sulfur subbituminous or Powder River Basin (PRB) in the River Rouge and Trenton Channel Power Plants has the potential to reduce SO_2 emissions to 0.8 lb/mmBtu based on a 12-month rolling average, and 1.3 lb/mmBtu on a 24-hour or daily average. As noted above, because of the natural variability of sulfur in coal, an unexpected coal shipment with an elevated sulfur content could result in emissions above the achievable emission rate when expressed on a lb/mmBtu basis, even if the mass emission rate of SO_2 emissions is relatively small. Therefore, the short term achievable emission rate for each boiler is the ***mass*** emission rate for the boiler, expressed in tons per day. Expressing the achievable emission rate in tons per day is consistent with the current SO_2 emission limits for these power plants.

7.5.2 Economic Feasibility.

Only the River Rouge Unit 3 and Trenton Channel Unit 9 are considered in the following analysis, because these units cannot burn 100% low sulfur subbituminous coal without a significant derating of the electric output of the units. The River Rouge Unit 3 is expected to be reduced by 20 MW, and the Trenton Channel Unit 9 is expected to be reduced by 50 MW if only low sulfur subbituminous coals were fired in these units. This derating would occur because the low sulfur subbituminous coals have a lower heating value than the design bituminous coals for these boilers. Because the boilers are limited in how many tons of coal they can fire in an hour, the lower heating value will reduce the steam output of the boiler and consequently reduce the maximum electric generating capacity of the unit.

The costs of the reduced electric output of these units would include a capacity derating which is typically expressed in $ per MW. This is a payment received simply to be available to generate electric power when requested. In addition, during peak load conditions which normally occur in the summer months, the reduced output will also result in a cost for the required purchase of additional electricity during these peak load periods. This replacement power cost will be higher than the cost of generation at these units, since the replacement power is normally only needed during peak periods when the cost of peak electric generating capacity is very high.

The costs for the use of 100% low sulfur subbituminous coal as compared to the use of an optimized low sulfur subbituminous coal/ low sulfur bituminous coal blend for River Rouge Unit 3 and Trenton Channel Unit 9 are summarized in Table 17. The values in Table 17 represent the annual average costs for the 7-year period from 2016 to 2022. These costs are based on projections which were made using the Ventyx PROMOD model. PROMOD is a widely used electric utility market simulation software package which incorporates generating unit operating characteristics, transmission grid constraints, unit commitment and operating conditions, and market system operations to forecast or predict electric generating unit utilization in the future. PROMOD IV performs an 8,760-hour commitment and dispatch recognizing both generation and transmission impacts. PROMOD IV forecasts hourly energy and loss prices, unit generation, revenues and fuel consumption, external market transactions, transmission flows.

The costs for this same control option, but based on a possible future electric generating capacity shortfall are summarized in Table 18. The costs in Table 18 reflect potential variability in the electric market conditions which can have a large impact on capacity costs. This volatility must be considered when assessing these costs because changes in the market can have large effects on the cost of utilizing only low sulfur western coals.

From Table 17, the use of 100% low sulfur subbituminous coal would have an average annual cost of \$2.07 million for River Rouge Unit 3, and would result in an SO_2 reduction of 1,048 tons per year, resulting in an average cost effectiveness of \$1,970 per ton. For Trenton Channel Unit 9, the use of 100% low sulfur subbituminous coal would also have an annual cost of \$2.12 million, but would result in an SO_2 reduction of only 558 tons per year, resulting in an average cost effectiveness of \$3,800 per ton. From Table 18, based on the potential for a tighter electric generating capacity market, the use of 100% low sulfur subbituminous coal would have an annual cost of \$2.35 million for River Rouge Unit 3. For a similar SO_2 reduction of 1,048 tons per year, would result in a cost effectiveness of \$2,240 per ton. For Trenton Channel Unit 9, the use of 100% low sulfur subbituminous coal and the potential tighter capacity market would have an annual cost of \$2.82 million. For an SO_2 reduction of only 558 tons per year, this annual cost would result in an average cost effectiveness of \$5,060 per ton. It is also important to note that for Trenton Channel Unit 9, the cost effectiveness in the individual years from 2016 to 2022 can be much more variable, ranging from \$1,870 to more than \$11,200 per ton of SO_2 controlled.

TABLE 17. Costs for the use of 100% low sulfur subbituminous coal as compared to the use of a low sulfur subbituminous/low sulfur bituminous coal blend.

Unit	Capacity Reduction	Capacity Factor	Annual Costs, \$			SO_2 Emission Reductions	Cost Effectiveness
	MW		Capacity	Generation	Total	ton/year	\$/ton
River Rouge 3	20	50%	\$622,300	\$1,444,400	\$2,066,700	1,048	\$1,970
Trenton 9	50	49%	\$1,555,700	\$566,700	\$2,122,400	558	\$3,800

TABLE 18. Costs for the use of 100% low sulfur subbituminous coal as compared to the use of a low sulfur subbit/low sulfur bit coal blend based on a tighter capacity market.

Unit	Capacity Reduction	Capacity Factor	Annual Costs, \$			SO_2 Emission Reductions	Cost Effectiveness
	MW		Capacity	Generation	Total	ton/year	\$/ton
River Rouge 3	20	50%	\$903,100	\$1,444,400	\$2,347,500	1,048	\$2,240
Trenton 9	50	49%	\$2,257,800	\$566,700	\$2,824,500	558	\$5,060

7.5.3 Conclusion.

For River Rouge Unit 3, the average cost effectiveness for the use of only subbituminous coal would range from $1,970 to $2,240 per ton of SO_2 controlled. As noted on page 15 of this analysis, U.S. EPA guidance from 1994 indicates that cost effectiveness should be within $160 to $1,300 per ton of pollutant controlled, equal to $250 to $2,050 per ton of pollutant controlled today. Although these costs are therefore at the upper end of the feasible costs for RACT, DTE Electric Company believes these costs are economically feasible for the River Rouge Unit 3. However, the costs for the use of the use of only low sulfur subbituminous coals in Trenton Channel Unit 9 would range from $3,800 to $5,060 per ton of SO_2 controlled. Furthermore, because of highly variable capacity prices in the future, the cost effectiveness in individual years can also be much more variable, ranging from $1,870 to more than $11,200 per ton of SO_2 controlled. This high cost is not economically feasible for Trenton Channel Unit 9.

Because the use of only low sulfur subbituminous coal in Trenton Channel Unit 9 would result in significant capacity deratings and significant costs but only moderate SO_2 reductions, an emission limitation based on the use of only 100% low sulfur subbituminous coals is not a reasonably available control technology for the control of SO_2 emissions from Trenton Channel Unit 9.

Chapter 8. Proposed SO_2 RACT Determination.

Based on this analysis, DTE Electric Company has concluded that an SO_2 emission rate equal to the use of low sulfur subbituminous coal is a reasonably available control technology (RACT) for the control of SO_2 emissions from the River Rouge Units 2 and 3, and the Trenton Channel Power Plant High Side Boilers 16, 17, 18, and 19. The River Rouge and Trenton Channel Power Plants currently utilize a blend of low sulfur bituminous and low sulfur subbituminous coals. An emission rate equal to the use of only low sulfur subbituminous coal (which is the lowest SO_2 emitting coal available) would further reduce SO_2 emissions from these power plants. The use of low sulfur subbituminous coal is expected to reduce SO_2 emissions to 0.8 lb/mmBtu based on a 12-month average, and 1.3 lb/mmBtu based on a 24-hour or daily average. Because of the natural variability of sulfur in coal, the short term achievable emission rate for each boiler is based on the mass emission rate for the boiler, expressed in tons per day. This change represents more than a 50% reduction from the current allowable emission rate for these units.

Because the use of only low sulfur subbituminous coal in Trenton Channel Unit 9 would result in a significant capacity derating of the unit and significant adverse economic costs, the use of only low sulfur subbituminous coals in Trenton Channel Unit 9 is not RACT for this unit. If only subbituminous coals are used in this unit, the maximum electric output would be reduced by approximately 50 MW. For the Trenton Channel Unit 9, the average cost effectiveness for the use of only subbituminous coal would range from $3,800 to $5,060 per ton of SO_2 controlled. Furthermore, because of highly variable capacity prices in the future, the cost effectiveness in individual years can also be much more variable, ranging from $1,870 to more than $11,200 per ton of SO_2 controlled. This high cost is not economically feasible. Based on this analysis, the use of a low sulfur subbituminous coal and bituminous coal blend is RACT for the control of SO_2 emissions from the Trenton Channel Unit 9. The use of this coal blend is expected to reduce SO_2 emissions to 1.2 lb/mmBtu based on a 12-month average, and 1.5 lb/mmBtu based on a 24-hour or daily average. This reduction represents a 29% reduction from the current allowable emission rate for this unit.

Other available control technologies are not economically feasible control options. Although wet and dry FGD systems can reduce SO_2 emissions by 90 to 95%, the costs for both wet and dry FGD systems exceed $5,080 per ton of SO_2 controlled for all units at their expected utilization equal to a 55% capacity factor. The high costs for wet and dry FGD systems reflect the high capital costs of these technologies. For the River Rouge and Trenton Channel Power Plants, these costs are estimated at $865 million for wet limestone forced oxidation (wet FGD) systems, and $990 million for lime spray dry FGD systems. Based on these high capital and operating costs, wet or dry FGD systems are not economically feasible and do not represent RACT for these units.

This analysis included two levels of reduction for the use of sorbent injection for SO_2 control. The first level of control is based on the use of sorbent injection optimized for SO_2 control. This control option is expected to achieve an SO_2 control efficiency of 40%. However, the use of sorbent injection optimized for SO_2 control is also not economically feasible, with average costs exceeding $6,750 per ton of SO_2 controlled. Because these power plants will require the use of sorbent injection for compliance with the Mercury and Air Toxics Standards (MATS) for coal-fired units under 40 CFR 63, Subpart UUUUU after the year 2016, the second level of control represents the SO_2 reduction expected to achieve the MACT standards. The use of sorbent injection to reduce hydrogen chloride (HCl) emissions for MATS compliance is expected to achieve a 10 to 15% reduction in the SO_2 emission rate, depending on the coal or coal blend used. However, the cost effectiveness for the control of SO_2 emissions based on the SO_2 reduction achieved through the use of sorbent injection for MATS compliance is also not economically feasible, with costs exceeding $12,720 per ton of SO_2 controlled.

Based on this RACT analysis, we have concluded that the sulfur dioxide (SO_2) limits in the following table represent RACT for the River Rouge and Trenton Channel Power Plants. The long term limit of 0.8 lb/mmBtu would result in a 52% reduction in the potential or allowable emissions from the River Rouge Units 2 and 3, and the Trenton Channel Power Plant High Side Boilers 16, 17, 18, and 19. The long term limit of 1.2 lb/mmBtu would result in a 28% reduction in the potential or allowable emissions for Trenton Channel Unit 9.

Proposed sulfur dioxide (SO_2) RACT emission limits for the River Rouge and Trenton Channel Power Plants.

Units	RACT Emission Limits
River Rouge Unit 2	0.8 lb/mmBtu, based on a 12-month rolling average.
River Rouge Unit 3	0.8 lb/mmBtu, based on a 12-month rolling average.
River Rouge Units 2 and 3 *Combined*	77.2 tons per day, based on a 24-hour or daily basis.
Trenton Channel Boilers 16, 17, 18, and 19	0.8 lb/mmBtu, based on a 12-month rolling average.
Trenton Channel Unit 9	1.2 lb/mmBtu, based on a 12-month rolling average.
Trenton Channel Boilers 16 - 19 and Unit 9 *Combined*	117.8 tons per day, based on a 24-hour or daily basis.

Attachment 1.

CUECost - Air Pollution Control Systems Economics Spreadsheet For the River Rouge and Trenton Channel Power Plants.

Capital and Operation Costs for New Wet Flue Gas Desulfurization Systems and New Dry Flue Gas Desulfurization Systems.

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

TABLE A1. Analysis of the cost effectiveness of the post combustion SO_2 control technology options for River Rouge Unit 2.

Parameter	wet FGD	Dry FGD	Sorbent Injection	Sorbent Injection (MATS)	Low Sulfur Coal
Controlled Emission Rate, lb/mmBtu	0.06	0.08	0.48	0.72	0.80
Heat Input Capacity, mmBtu/hr	2,280	2,280	2,280	2,280	2,280
Utilization, %	55%	55%	55%	55%	55%
Actual SO_2 Emissions, tons per year	330	439	2,636	3,955	4,394
Total Capital Requirement, $	$195,555,000	$215,627,000	$11,680,000	$11,680,000	n/a
Capital Recovery Factor (CRF)	0.1987	0.1987	0.1987	0.1987	0.1987
Annual Capital Cost, $/yr	$38,854,900	$42,843,000	$2,320,700	$2,320,700	n/a
Annual O&M Cost, $/yr	$8,334,500	$9,588,200	$16,971,900	$11,314,600	n/a
Total Annual Cost, $/yr	$47,189,400	$52,431,200	$19,292,600	$13,635,300	
Average Annual Cost, $/yr	$47,189,400	$52,431,200	$19,292,600	$13,635,300	
Average SO_2 Reduction, tons per year	4,064	3,955	1,758	439	
Average Cost per Ton Reduced, $ per ton	$11,610	$13,260	$10,980	$31,030	

Footnotes

1. The *Controlled Emission Rate* is from the RACT analysis, Table 7.
2. The *Actual SO_2 Emissions* are based on the Controlled Emission Rate, the Maximum Heat Input Capacity, and the stated Uti
3. The *Total Capital Requiremen* t is from the U.S. EPA's Coal Utility Environmental Cost (CUECOST) software.
4. The *Annual Capital Cost* or capital recovery cost is calculated by multiplying the capital recovery factor (CRF) by the Total Capital Requirement as detailed in the U.S. EPA's EPA Air Pollution Control Cost Manual - Sixth Edition (EPA 452/B-02-001), available at: http://www.epa.gov/ttncatc1/products html

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$

where:
i = annual interest rate = 9.0%
n = project life, years = 7

5. The *Total Annual Cost* is the sum of the Annual Capital Costs and the Annual O&M Costs.
6. The *Average Annual Cost* is the Total Annual Cost of the control option.
7. The *Average SO_2 Reduction* is the Uncontrolled Low Sulfur Coal Emission Rate minus the Actual Emission Rate of the control option.
8. The *Average Cost per Ton Reduced* is the Average Annual Cost of the control option divided by the Average SO_2 Reduction of the control option:

$$\text{Average Cost Effectiveness (\$ per ton removed)} = \frac{\text{Control option annual cost}}{\text{seline emission rate – Control option emissions rate}}$$

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

TABLE A2. Analysis of the cost effectiveness of the post combustion SO_2 control technology options for River Rouge Unit 3.

Parameter	wet FGD	Dry FGD	Sorbent Injection	Sorbent Injection (MATS)	Low Sulfur Coal
Controlled Emission Rate, lb/mmBtu	0.06	0.08	0.72	1.02	1.20
Heat Input Capacity, mmBtu/hr	2,670	2,670	2,670	2,670	2,670
Utilization, %	55%	55%	55%	55%	55%
Actual SO_2 Emissions, tons per year	386	515	4,631	6,561	7,718
Total Capital Requirement, $	$217,194,000	$247,673,000	$15,400,000	$15,400,000	n/a
Capital Recovery Factor (CRF)	0.1987	0.1987	0.1987	0.1987	0.1987
Annual Capital Cost, $/yr	$43,154,400	$49,210,300	$3,059,800	$3,059,800	n/a
Annual O&M Cost, $/yr	$9,837,200	$11,732,000	$22,377,300	$14,918,200	n/a
Total Annual Cost, $/yr	$52,991,600	$60,942,300	$25,437,100	$17,978,000	
Average Annual Cost, $/yr	$52,991,600	$60,942,300	$25,437,100	$17,978,000	
Average SO_2 Reduction, tons per year	7,333	7,204	3,087	1,158	
Average Cost per Ton Reduced, $ per ton	$7,230	$8,460	$8,240	$15,530	

Footnotes

1. The *Controlled Emission Rate* is from the RACT analysis, Table 7.
2. The *Actual SO_2 Emissions* are based on the Controlled Emission Rate, the Maximum Heat Input Capacity, and the stated Uti
3. The *Total Capital Requiremen* t is from the U.S. EPA's Coal Utility Environmental Cost (CUECOST) software.
4. The *Annual Capital Cost* or capital recovery cost is calculated by multiplying the capital recovery factor (CRF) by the Total Capital Requirement as detailed in the U.S. EPA's EPA Air Pollution Control Cost Manual - Sixth Edition (EPA 452/B-02-001), available at: http://www.epa.gov/ttncatc1/products html

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$

where:
i = annual interest rate = 9.0%
n = project life, years = 7

5. The *Total Annual Cost* is the sum of the Annual Capital Costs and the Annual O&M Costs.
6. The *Average Annual Cost* is the Total Annual Cost of the control option.
7. The *Average SO_2 Reduction* is the Uncontrolled Low Sulfur Coal Emission Rate minus the Actual Emission Rate of the control option.
8. The *Average Cost per Ton Reduced* is the Average Annual Cost of the control option divided by the Average SO_2 Reduction of the control option:

$$\text{Average Cost Effectiveness (\$ per ton removed)} = \frac{\text{Control option annual cost}}{\text{seline emission rate – Control option emissions rate}}$$

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

TABLE A3. Analysis of the cost effectiveness of the post combustion SO_2 control technology options for the Trenton Channel Boilers 16, 17, 18, and 19.

Parameter	wet FGD	Dry FGD	Sorbent Injection	Sorbent Injection (MATS)	Low Sulfur Coal
Controlled Emission Rate, lb/mmBtu	0.06	0.08	0.48	0.72	0.80
Heat Input Capacity, mmBtu/hr	3,023	3,023	3,023	3,023	3,023
Utilization, %	55%	55%	55%	55%	55%
Actual SO_2 Emissions, tons per year	437	583	3,496	5,243	5,826
Total Capital Requirement, $	$195,482,000	$215,633,000	$14,400,000	$14,400,000	n/a
Capital Recovery Factor (CRF)	0.1987	0.1987	0.1987	0.1987	0.1987
Annual Capital Cost, $/yr	$38,840,400	$42,844,200	$2,861,100	$2,861,100	n/a
Annual O&M Cost, $/yr	$8,018,500	$9,535,400	$13,949,600	$9,299,700	n/a
Total Annual Cost, $/yr	$46,858,900	$52,379,600	$16,810,700	$12,160,800	
Average Annual Cost, $/yr	$46,858,900	$52,379,600	$16,810,700	$12,160,800	
Average SO_2 Reduction, tons per year	5,389	5,243	2,330	583	
Average Cost per Ton Reduced, $ per ton	$8,700	$9,990	$7,210	$20,870	

Footnotes

1. The *Controlled Emission Rate* is from the RACT analysis, Table 7.
2. The *Actual SO_2 Emissions* are based on the Controlled Emission Rate, the Maximum Heat Input Capacity, and the stated Uti
3. The *Total Capital Requiremen* t is from the U.S. EPA's Coal Utility Environmental Cost (CUECOST) software.
4. The *Annual Capital Cost* or capital recovery cost is calculated by multiplying the capital recovery factor (CRF) by the Total Capital Requirement as detailed in the U.S. EPA's EPA Air Pollution Control Cost Manual - Sixth Edition (EPA 452/B-02-001), available at: http://www.epa.gov/ttncatc1/products html

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$

where:
i = annual interest rate = 9.0%
n = project life, years = 7

5. The *Total Annual Cost* is the sum of the Annual Capital Costs and the Annual O&M Costs.
6. The *Average Annual Cost* is the Total Annual Cost of the control option.
7. The *Average SO_2 Reduction* is the Uncontrolled Low Sulfur Coal Emission Rate minus the Actual Emission Rate of the control option.
8. The *Average Cost per Ton Reduced* is the Average Annual Cost of the control option divided by the Average SO_2 Reduction of the control option:

$$\text{Average Cost Effectiveness (\$ per ton removed)} = \frac{\text{Control option annual cost}}{\text{seline emission rate – Control option emissions rate}}$$

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

TABLE A4. Analysis of the cost effectiveness of the post combustion SO_2 control technology options for the Trenton Channel Unit 9.

Parameter	wet FGD	Dry FGD	Sorbent Injection	Sorbent Injection (MATS)	Low Sulfur Coal Blend
Controlled Emission Rate, lb/mmBtu	0.06	0.08	0.72	1.02	1.20
Heat Input Capacity, mmBtu/hr	4,530	4,530	4,530	4,530	4,530
Utilization, %	55%	55%	55%	55%	55%
Actual SO_2 Emissions, tons per year	655	873	7,857	11,131	13,095
Total Capital Requirement, $	$257,000,000	$312,372,000	$21,400,000	$21,400,000	n/a
Capital Recovery Factor (CRF)	0.1987	0.1987	0.1987	0.1987	0.1987
Annual Capital Cost, $/yr	$51,063,500	$62,065,400	$4,252,000	$4,252,000	n/a
Annual O&M Cost, $/yr	$12,106,100	$11,568,300	$31,095,800	$20,730,500	n/a
Total Annual Cost, $/yr	$63,169,600	$73,633,700	$35,347,800	$24,982,500	
Average Annual Cost, $/yr	$63,169,600	$73,633,700	$35,347,800	$24,982,500	
Average SO_2 Reduction, tons per year	12,441	12,222	5,238	1,964	
Average Cost per Ton Reduced, $ per ton	$5,080	$6,020	$6,750	$12,720	

Footnotes

1. The *Controlled Emission Rate* is from the RACT analysis, Table 7.
2. The *Actual SO_2 Emissions* are based on the Controlled Emission Rate, the Maximum Heat Input Capacity, and the stated Uti
3. The *Total Capital Requiremen* t is from the U.S. EPA's Coal Utility Environmental Cost (CUECOST) software.
4. The *Annual Capital Cost* or capital recovery cost is calculated by multiplying the capital recovery factor (CRF) by the Total Capital Requirement as detailed in the U.S. EPA's EPA Air Pollution Control Cost Manual - Sixth Edition (EPA 452/B-02-001), available at: http://www.epa.gov/ttncatc1/products html

$$CRF = \frac{i(1+i)^n}{\left[(1+i)^n - 1\right]}$$

where:
i = annual interest rate = 9.0%
n = project life, years = 7

5. The *Total Annual Cost* is the sum of the Annual Capital Costs and the Annual O&M Costs.
6. The *Average Annual Cost* is the Total Annual Cost of the control option.
7. The *Average SO_2 Reduction* is the Uncontrolled Low Sulfur Coal Emission Rate minus the Actual Emission Rate of the control option.
8. The *Average Cost per Ton Reduced* is the Average Annual Cost of the control option divided by the Average SO_2 Reduction of the control option:

$$\text{Average Cost Effectiveness (\$ per ton removed)} = \frac{\text{Control option annual cost}}{\text{seline emission rate – Control option emissions rate}}$$

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

Description	Units	RR Unit 2	RR Unit 3	TC High	TC Unit 9
General Plant Technical Inputs					
Location - State	Abbrev.	MI	MI	MI	MI
MW Equivalent of Flue Gas to Control System	MW	292	385	240	535
Net Plant Heat Rate	Btu/kWhr	10,300	10,300	12,600	10,300
Plant Capacity Factor	%	55%	55%	55%	55%
Total Air Downstream of Economizer	%	120%	120%	120%	120%
Air Heater Leakage	%	12%	12%	12%	12%
Air Heater Outlet Gas Temperature	°F	300	300	300	300
Inlet Air Temperature	°F	45	45	45	45
Ambient Absolute Pressure	In. of Hg	29.4	29.4	29.4	29.4
Pressure After Air Heater	In. of H2O	-12	-12	-12	-12
Moisture in Air	lb/lb dry air	0.013	0.013	0.013	0.013
Ash Split:					
Fly Ash	%	80%	80%	80%	80%
Bottom Ash	%	20%	20%	20%	20%
Seismic Zone	Integer	1	1	1	1
Retrofit Factor	Integer	2.2	2.2	2.2	2.2
(1.0 = new, 1.3 = medium, 1.6 = difficult)					
Select Coal	Integer	1	1	1	1
Is Selected Coal a Powder River Basin Coal?	Yes / No	Yes	Yes	Yes	Yes
Economic Inputs					
Cost Basis -Year Dollars	Year	2013	2013	2013	2013
Sevice Life (levelization period)	Years	20	20	20	20
Inflation Rate	%	3.0%	3.0%	3.0%	3.0%
After Tax Discount Rate (current $'s)	%	9.2%	9.2%	9.2%	9.2%
AFDC Rate (current $'s)	%	10.8%	10.8%	10.8%	10.8%
First-year Carrying Charge (current $'s)	%	22.3%	22.3%	22.3%	22.3%
Levelized Carrying Charge (current $'s)	%	16.9%	16.9%	16.9%	16.9%
First-year Carrying Charge (constant $'s)	%	15.7%	15.7%	15.7%	15.7%
Levelized Carrying Charge (constant $'s)	%	11.7%	11.7%	11.7%	11.7%
Sales Tax	%	6.0%	6.0%	6.0%	6.0%
Escalation Rates:					
Consumables (O&M)	%	3%	3%	3%	3%
Capital Costs:					
Is Chem. Eng. Cost Index available?	Yes / No	Yes	Yes	Yes	Yes
If "Yes" input cost basis CE Plant Inde	Integer	593.8	593.8	593.8	593.8
If "No" input escalation rate.	%	3%	3%	3%	3%
Construction Labor Rate	$/hr	$35	$35	$35	$35
Prime Contractor's Markup	%	3%	3%	3%	3%
Operating Labor Rate	$/hr	$30	$30	$30	$30
Power Cost	Mills/kWh	25	25	25	25
Steam Cost	$/1000 lbs	3.5	3.5	3.5	3.5

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

Description	Units	RR Unit 2	RR Unit 3	TC High	TC Unit 9
Limestone Forced Oxidation (LSFO) Inputs					
Uncontrolled SO2 Emission Rate	lb/mmBtu	4.0	5.8		
SO2 Removal Required	%	95%	95%	95%	95%
L/G Ratio	gal / 1000 acf	125	125	125	125
Design Scrubber with Dibasic Acid Addition?	Integer	2	2	2	2
Adiabatic Saturation Temperature	°F	127	127	127	127
Reagent Feed Ratio (Mole CaCO3 / Mole SO2	Factor	1.05	1.05	1.05	1.05
Scrubber Slurry Solids Concentration	Wt. %	15%	15%	15%	15%
Stacking, Landfill, Wallboard	Integer	2	2	2	2
(1 = stacking, 2 = lanfill, 3 = wallboard)					
Number of Absorbers	Integer	1	1	1	1
(Max. Capacity = 700 MW per absorber)					
Absorber Material (1 = alloy, 2 = RLCS)	Integer	1	1	1	1
Absorber Pressure Drop	in. H2O	6	6	6	6
Reheat Required ? (1 = yes, 2 = no)	Integer	1	1	1	1
Amount of Reheat	°F	25	25	25	25
Reagent Bulk Storage	Days	60	60	60	60
Reagent Cost (delivered)	$/ton	$22	$22	$22	$22
Landfill Disposal Cost	$/ton	$30	$30	$30	$30
Stacking Disposal Cost	$/ton	$6	$6	$6	$6
Credit for Gypsum Byproduct	$/ton	$2	$2	$2	$2
Maintenance Factors by Area (% of Installed Cost)					
Reagent Feed	%	5%	5%	5%	5%
SO2 Removal	%	5%	5%	5%	5%
Flue Gas Handling	%	5%	5%	5%	5%
Waste / Byproduct	%	5%	5%	5%	5%
Support Equipment	%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)					
Reagent Feed	%	20%	20%	20%	20%
SO2 Removal	%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)					
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)					
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

Description	Units	RR Unit 2	RR Unit 3	TC High	TC Unit 9
Lime Spray Dryer (LSD) Inputs					
SO2 Removal Required	%	93.3%	93.3%	93%	93%
Adiabatic Saturation Temperature	°F	127	127	127	127
Flue Gas Approach to Saturation	°F	20	20	20	20
Spray Dryer Outlet Temperature	°F	147	147	147	147
Reagent Feed Ratio	Factor	0.95	0.95	0.95	0.95
(Mole CaO / Mole Inlet SO2)					
Recycle Rate	Factor	30	30	30	30
(lb recycle / lb lime feed)					
Recycle Slurry Solids Concentration	Wt. %	35%	35%	35%	35%
Number of Absorbers	Integer	2	2	2	2
(Max. Capacity = 300 MW per spray dryer)					
Absorber Material	Integer	1	1	1	1
(1 = alloy, 2 = RLCS)					
Spray Dryer Pressure Drop	in. H2O	5	5	5	5
Reagent Bulk Storage	Days	60	60	60	60
Reagent Cost (delivered)	$/ton	$65	$65	$65	$65
Dry Waste Disposal Cost	$/ton	$30	$30	$30	$30
Maintenance Factors by Area (% of Installed Cost)					
Reagent Feed	%	5%	5%	5%	5%
SO2 Removal	%	5%	5%	5%	5%
Flue Gas Handling	%	5%	5%	5%	5%
Waste / Byproduct	%	5%	5%	5%	5%
Support Equipment	%	5%	5%	5%	5%
Contingency by Area (% of Installed Cost)					
Reagent Feed	%	20%	20%	20%	20%
SO2 Removal	%	20%	20%	20%	20%
Flue Gas Handling	%	20%	20%	20%	20%
Waste / Byproduct	%	20%	20%	20%	20%
Support Equipment	%	20%	20%	20%	20%
General Facilities by Area (% of Installed Cost)					
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%
Engineering Fees by Area (% of Installed Cost)					
Reagent Feed	%	10%	10%	10%	10%
SO2 Removal	%	10%	10%	10%	10%
Flue Gas Handling	%	10%	10%	10%	10%
Waste / Byproduct	%	10%	10%	10%	10%
Support Equipment	%	10%	10%	10%	10%

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

Wet FGD Limestone Forced Oxidation		RR Unit 2	RR Unit 3	TC High	TC Unit 9

LSFO Equipment Capital Costs

	Cost Basis (Year)	***2013***	***2013***	***2013***	***2013***
	Sizing Criteria				
Reagent Feed System	kpph Reag.	$11,340,729	$11,477,008	$11,343,086	$11,691,398
Ball Mill & Hydroclone System	TPH Reag.	$2,914,804	$2,939,125	$2,915,220	$2,978,537
DBA Acid Tank (pump, heater, a	gpm DBA	$0	$0	$0	$0
SO2 Removal System	kpph SO2	$3,057,789	$3,102,123	$3,058,552	$3,172,917
Absorber Tower	kACFM	$18,063,667	$21,110,855	$18,119,134	$25,421,794
Spray Pumps	slurry gpm	$2,154,830	$2,854,024	$2,161,818	$3,800,939
Flue Gas Handling System	*	$7,986,613	$9,094,721	$8,006,719	$10,608,724
ID Fans	ACFM	$2,423,194	$2,927,827	$2,432,226	$3,668,423
Waste / Byproduct Handling System	kpph SO2	$1,301,823	$1,338,764	$1,302,459	$1,397,673
Thickener System	TPH solids	$225,802	$241,877	$226,077	$267,858
Support Equipment	MW	$2,565,555	$2,761,316	$2,446,963	$3,038,347
Chimney	ACFM	$5,924,674	$6,497,683	$5,935,442	$7,253,569
TOTAL		$57,959,480	$64,345,322	$57,947,696	$73,300,179

* *Based on flue gas flow and reheat temperature.*

Capital Costs with Retrofit Factors				
Reagent Feed System	$24,949,603	$25,249,417	$24,954,789	$25,721,076
Ball Mill & Hydroclone System	$6,412,569	$6,466,075	$6,413,484	$6,552,781
DBA Acid Tank (pump, heater, agitator)	$0	$0	$0	$0
SO2 Removal System	$6,727,136	$6,824,671	$6,728,814	$6,980,416
Absorber Tower	$39,740,067	$46,443,881	$39,862,096	$55,927,946
Spray Pumps	$4,740,626	$6,278,852	$4,756,000	$8,362,065
Flue Gas Handling System	$17,570,548	$20,008,387	$17,614,782	$23,339,193
ID Fans	$5,331,026	$6,441,219	$5,350,898	$8,070,531
Waste / Byproduct Handling System	$2,864,012	$2,945,281	$2,865,410	$3,074,881
Thickener System	$496,763	$532,130	$497,369	$589,287
Support Equipment	$5,644,221	$6,074,895	$5,383,319	$6,684,364
Chimney	$13,034,284	$14,294,902	$13,057,972	$15,957,853
TOTAL	$127,510,855	$141,559,709	$127,484,931	$161,260,393

General Facilities				
Reagent Feed System	$2,494,960	$2,524,942	$2,495,479	$2,572,108
Ball Mill & Hydroclone System	$641,257	$646,608	$641,348	$655,278
DBA Acid Tank (pump, heater, agitator)	$0	$0	$0	$0
SO2 Removal System	$672,714	$682,467	$672,881	$698,042
Absorber Tower	$3,974,007	$4,644,388	$3,986,210	$5,592,795
Spray Pumps	$474,063	$627,885	$475,600	$836,207
Flue Gas Handling System	$1,757,055	$2,000,839	$1,761,478	$2,333,919
ID Fans	$533,103	$644,122	$535,090	$807,053
Waste / Byproduct Handling System	$286,401	$294,528	$286,541	$307,488
Thickener System	$49,676	$53,213	$49,737	$58,929
Support Equipment	$564,422	$607,490	$538,332	$668,436
Chimney	$1,303,428	$1,429,490	$1,305,797	$1,595,785

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

Wet FGD Limestone Forced Oxidation	RR Unit 2	RR Unit 3	TC High	TC Unit 9
TOTAL	$12,751,086	$14,155,971	$12,748,493	$16,126,039
Engineering Fees				
Reagent Feed System	$2,494,960	$2,524,942	$2,495,479	$2,572,108
Ball Mill & Hydroclone System	$641,257	$646,608	$641,348	$655,278
DBA Acid Tank (pump, heater, agitator)	$0	$0	$0	$0
SO2 Removal System	$672,714	$682,467	$672,881	$698,042
Absorber Tower	$3,974,007	$4,644,388	$3,986,210	$5,592,795
Spray Pumps	$474,063	$627,885	$475,600	$836,207
Flue Gas Handling System	$1,757,055	$2,000,839	$1,761,478	$2,333,919
ID Fans	$533,103	$644,122	$535,090	$807,053
Waste / Byproduct Handling System	$286,401	$294,528	$286,541	$307,488
Thickener System	$49,676	$53,213	$49,737	$58,929
Support Equipment	$564,422	$607,490	$538,332	$668,436
Chimney	$1,303,428	$1,429,490	$1,305,797	$1,595,785
TOTAL	$12,751,086	$14,155,971	$12,748,493	$16,126,039
Contingency				
Reagent Feed System	$4,989,921	$5,049,883	$4,990,958	$5,144,215
Ball Mill & Hydroclone System	$1,282,514	$1,293,215	$1,282,697	$1,310,556
DBA Acid Tank (pump, heater, agitator)	$0	$0	$0	$0
SO2 Removal System	$1,345,427	$1,364,934	$1,345,763	$1,396,083
Absorber Tower	$7,948,013	$9,288,776	$7,972,419	$11,185,589
Spray Pumps	$948,125	$1,255,770	$951,200	$1,672,413
Flue Gas Handling System	$3,514,110	$4,001,677	$3,522,956	$4,667,839
ID Fans	$1,066,205	$1,288,244	$1,070,180	$1,614,106
Waste / Byproduct Handling System	$572,802	$589,056	$573,082	$614,976
Thickener System	$99,353	$106,426	$99,474	$117,857
Support Equipment	$1,128,844	$1,214,979	$1,076,664	$1,336,873
Chimney	$2,606,857	$2,858,980	$2,611,594	$3,191,571
TOTAL	$25,502,171	$28,311,942	$25,496,986	$32,252,079
Total Plant Cost (TPC)	$178,515,197	$198,183,593	$178,478,904	$225,764,551
Total Plant Cost (TPC) w/ Prime Contractor's Marl	$183,870,653	$204,129,101	$183,833,271	$232,537,487
Total Cash Expended (TCE)	$181,192,925	$201,156,347	$181,156,087	$225,830,307
Allow. for Funds During Constr. (AFDC)	$9,639,821	$10,701,914	$9,637,861	$24,761,330
Total Plant Investment (TPI)	$190,832,746	$211,858,261	$190,793,948	$250,591,637
Preproduction Costs	$4,652,735	$5,243,550	$4,617,599	$6,280,155
Inventory Capital	$70,004	$92,300	$70,386	$128,334
TOTAL CAPITAL REQUIREMENT (TCR)	***$195,555,486***	***$217,194,111***	***$195,481,934***	***$257,000,126***
	$670	$564	$815	$480
Maintenance Cost by Area				
TPC w/o Retrofit Factor				
Reagent Feed System	$16,330,650	$16,526,891	$16,334,043	$16,835,614

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

Wet FGD Limestone Forced Oxidation	RR Unit 2	RR Unit 3	TC High	TC Unit 9
Ball Mill & Hydroclone System	$4,197,318	$4,232,340	$4,197,917	$4,289,093
DBA Acid Tank (pump, heater, agitator)	$0	$0	$0	$0
SO2 Removal System	$4,403,217	$4,467,057	$4,404,315	$4,569,000
Absorber Tower	$26,011,680	$30,399,631	$26,091,553	$36,607,383
Spray Pumps	$3,102,955	$4,109,794	$3,113,018	$5,473,352
Flue Gas Handling System	$11,500,722	$13,096,399	$11,529,675	$15,276,563
ID Fans	$3,489,399	$4,216,071	$3,502,406	$5,282,529
Waste / Byproduct Handling System	$1,874,626	$1,927,820	$1,875,541	$2,012,649
Thickener System	$325,154	$348,303	$325,551	$385,715
Support Equipment	$3,694,399	$3,976,295	$3,523,627	$4,375,220
Chimney	$8,531,531	$9,356,663	$8,547,036	$10,445,140
TOTAL	$83,461,651	$92,657,264	$83,444,682	$105,552,257
First Year Maintenance Costs				
Reagent Feed System	$816,532	$826,345	$816,702	$841,781
Ball Mill & Hydroclone System	$209,866	$211,617	$209,896	$214,455
DBA Acid Tank (pump, heater, agitator)	$0	$0	$0	$0
SO2 Removal System	$220,161	$223,353	$220,216	$228,450
Absorber Tower	$1,300,584	$1,519,982	$1,304,578	$1,830,369
Spray Pumps	$155,148	$205,490	$155,651	$273,668
Flue Gas Handling System	$575,036	$654,820	$576,484	$763,828
ID Fans	$174,470	$210,804	$175,120	$264,126
Waste / Byproduct Handling System	$93,731	$96,391	$93,777	$100,632
Thickener System	$16,258	$17,415	$16,278	$19,286
Support Equipment	$184,720	$198,815	$176,181	$218,761
Chimney	$426,577	$467,833	$427,352	$522,257
TOTAL	**$4,173,083**	**$4,632,863**	**$4,172,234**	**$5,277,613**

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

Wet FGD Limestone Forced Oxidation	RR Unit 2	RR Unit 3	TC High	TC Unit 9

LSFO O&M Data and Costs

Cost Basis (Year)	*2013*	*2013*	*2013*	*2013*
Parameters				
Reagent Required	4,419	5,827	4,444	8,102
	1.469	1.469	1.469	1.469
DBA Required	0.0	0.0	0.0	0.0
Percent SO2 Removal	95%	95%	95%	95%
FGD Sludge to Disposal	7,314	9,643	7,354	13,408
Steam to FGD System	36,157	47,673	36,354	66,284
Total FGD Power Consumption	5,840	7,700	4,800	10,706
FGD Byproduct	0	0	0	0
Fixed O&M Costs				
Number of Operators (40 hrs/week)	20	24	17	29
Operating Labor Cost **	$1,218,971	$1,470,176	$1,067,267	$1,838,112
Maint. Labor & Matls. Cost	$4,173,083	$4,632,863	$4,172,234	$5,277,613
Admin. & Support Labor	$866,461	$996,996	$820,848	$1,184,747
TOTAL	**$6,258,515**	**$7,100,036**	**$6,060,350**	**$8,300,472**
Variable Operating Costs **				
Reagent Costs	$234,223	$308,822	$235,501	$429,383
DBA Costs	$0	$0	$0	$0
Disposal Costs	$528,576	$696,923	$531,458	$968,995
Credit for Byproduct	$0	$0	$0	$0
Steam Costs	$609,720	$803,911	$613,044	$1,117,750
Power Costs	$703,428	$927,465	$578,160	$1,289,538
TOTAL	**$2,075,947**	**$2,737,121**	**$1,958,163**	**$3,805,665**
TOTAL O&M COSTS	***$8,334,462***	***$9,837,157***	***$8,018,513***	***$12,106,137***

** *These costs assume inputs are in current dollars (no escalation included).*

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

dry FGD Lime Spray Dry (LSD) System		RR Unit 2	RR Unit 3	TC High	TC Unit 9
LSD Equipment Capital Costs					
	Cost Basis (Year)	**2013**	**2013**	**2013**	**2013**
	Sizing Criteria				
Reagent Feed System	*	$6,684,122	$6,916,648	$6,688,146	$7,284,853
SO2 Removal System	Wt. % S	$2,214,137	$2,214,137	$2,214,137	$2,214,137
Spray Dryers	kACFM	$20,449,054	$23,853,138	$20,515,688	$27,255,792
Flue Gas Handling System	kACFM	$3,842,151	$4,498,106	$3,854,054	$5,432,546
ID Fans	ACFM	$1,792,841	$2,161,670	$1,799,439	$2,703,455
Waste / Byproduct Handling System	kpph SO2	$1,605,753	$1,605,753	$1,605,753	$1,605,753
Support Equipment	MW	$3,123,706	$3,391,903	$2,959,773	$3,757,571
Chimney	ACFM	$6,131,262	$6,717,380	$6,142,264	$7,492,051
TOTAL		$45,843,026	$51,358,734	$45,779,254	$57,746,158

* *Based on lbs/hr of lime feed and GPM of lime slurry.*

Capital Costs with Retrofit Factors	RR Unit 2	RR Unit 3	TC High	TC Unit 9
Reagent Feed System	$14,705,069	$15,216,625	$14,713,922	$16,026,676
SO2 Removal System	$4,871,101	$4,871,101	$4,871,101	$4,871,101
Spray Dryers	$44,987,918	$52,476,904	$45,134,513	$59,962,743
Flue Gas Handling System	$8,452,732	$9,895,833	$8,478,919	$11,951,602
ID Fans	$3,944,250	$4,755,674	$3,958,767	$5,947,600
Waste / Byproduct Handling System	$3,532,657	$3,532,657	$3,532,657	$3,532,657
Support Equipment	$6,872,154	$7,462,187	$6,511,500	$8,266,657
Chimney	$13,488,776	$14,778,236	$13,512,981	$16,482,512
TOTAL	$100,854,657	$112,989,216	$100,714,359	$127,041,548

General Facilities	RR Unit 2	RR Unit 3	TC High	TC Unit 9
Reagent Feed System	$1,470,507	$1,521,663	$1,471,392	$1,602,668
SO2 Removal System	$487,110	$487,110	$487,110	$487,110
Spray Dryers	$4,498,792	$5,247,690	$4,513,451	$5,996,274
Flue Gas Handling System	$845,273	$989,583	$847,892	$1,195,160
ID Fans	$394,425	$475,567	$395,877	$594,760
Waste / Byproduct Handling System	$353,266	$353,266	$353,266	$353,266
Support Equipment	$687,215	$746,219	$651,150	$826,666
Chimney	$1,348,878	$1,477,824	$1,351,298	$1,648,251
TOTAL	$10,085,466	$11,298,922	$10,071,436	$12,704,155

Engineering Fees	RR Unit 2	RR Unit 3	TC High	TC Unit 9
Reagent Feed System	$1,470,507	$1,521,663	$1,471,392	$1,602,668
SO2 Removal System	$487,110	$487,110	$487,110	$487,110
Spray Dryers	$4,498,792	$5,247,690	$4,513,451	$5,996,274
Flue Gas Handling System	$845,273	$989,583	$847,892	$1,195,160
ID Fans	$394,425	$475,567	$395,877	$594,760
Waste / Byproduct Handling System	$353,266	$353,266	$353,266	$353,266
Support Equipment	$687,215	$746,219	$651,150	$826,666
Chimney	$1,348,878	$1,477,824	$1,351,298	$1,648,251
TOTAL	$10,085,466	$11,298,922	$10,071,436	$12,704,155

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

dry FGD Lime Spray Dry (LSD) System	RR Unit 2	RR Unit 3	TC High	TC Unit 9
Contingency				
Reagent Feed System	$2,941,014	$3,043,325	$2,942,784	$3,205,335
SO2 Removal System	$974,220	$974,220	$974,220	$974,220
Spray Dryers	$8,997,584	$10,495,381	$9,026,903	$11,992,549
Flue Gas Handling System	$1,690,546	$1,979,167	$1,695,784	$2,390,320
ID Fans	$788,850	$951,135	$791,753	$1,189,520
Waste / Byproduct Handling System	$706,531	$706,531	$706,531	$706,531
Support Equipment	$1,374,431	$1,492,437	$1,302,300	$1,653,331
Chimney	$2,697,755	$2,955,647	$2,702,596	$3,296,502
TOTAL	$20,170,931	$22,597,843	$20,142,872	$25,408,310
Total Plant Cost (TPC)	$141,196,520	$158,184,902	$141,000,102	$177,858,167
Total Plant Cost (TPC) w/ Prime Contractor's Mark	$145,432,415	$162,930,449	$145,230,105	$183,193,912
Total Cash Expended (TCE)	$143,314,468	$160,557,676	$143,115,104	$177,909,970
Allow. for Funds During Constr. (AFDC)	$7,624,612	$8,541,985	$7,614,006	$19,507,069
Total Plant Investment (TPI)	$150,939,080	$169,099,660	$150,729,109	$197,417,039
Preproduction Costs	$3,771,090	$4,296,464	$3,750,019	$5,100,831
Inventory Capital	$117,160	$154,475	$117,799	$214,780
TOTAL CAPITAL REQUIREMENT (TCR)	***$154,827,330***	***$173,550,599***	***$154,596,927***	***$202,732,650***
	$530	$451	$644	$379

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

dry FGD Lime Spray Dry (LSD) System	**RR Unit 2**	**RR Unit 3**	**TC High**	**TC Unit 9**
Maintenance Cost by Area	Case 1	Case 2	Case 3	Case 4
TPC w/o Retrofit Factor				
Reagent Feed System	$9,625,136	$9,959,973	$9,630,931	$10,490,188
SO2 Removal System	$3,188,357	$3,188,357	$3,188,357	$3,188,357
Spray Dryers	$29,446,637	$34,348,519	$29,542,590	$39,248,341
Flue Gas Handling System	$5,532,698	$6,477,272	$5,549,838	$7,822,867
ID Fans	$2,581,691	$3,112,805	$2,591,193	$3,892,975
Waste / Byproduct Handling System	$2,312,284	$2,312,284	$2,312,284	$2,312,284
Support Equipment	$4,498,137	$4,884,340	$4,262,072	$5,410,903
Chimney	$8,829,017	$9,673,028	$8,844,860	$10,788,553
TOTAL	$66,013,957	$73,956,578	$65,922,126	$83,154,468
First Year Maintenance Costs				
Reagent Feed System	$481,257	$497,999	$481,547	$524,509
SO2 Removal System	$159,418	$159,418	$159,418	$159,418
Spray Dryers	$1,472,332	$1,717,426	$1,477,130	$1,962,417
Flue Gas Handling System	$276,635	$323,864	$277,492	$391,143
ID Fans	$129,085	$155,640	$129,560	$194,649
Waste / Byproduct Handling System	$115,614	$115,614	$115,614	$115,614
Support Equipment	$224,907	$244,217	$213,104	$270,545
Chimney	$441,451	$483,651	$442,243	$539,428
TOTAL	$3,300,698	$3,697,829	$3,296,106	$4,157,723

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

dry FGD Lime Spray Dry (LSD) System	RR Unit 2	RR Unit 3	TC High	TC Unit 9

LSD O&M Data and Costs

Cost Basis (Year)	2013	2013	2013	2013
Parameters				
Reagent Required	2,503	3,301	2,517	4,589
	0.832	0.832	0.832	0.832
Percent SO2 Removal	93%	93%	93%	93%
FGD Solids - dry	22,113	29,155	22,233	40,537
- wetted	27,641	36,444	27,792	50,672
Fresh Water to FGD	16	22	17	30
Blowdown Water to FGD	309	398	311	543
Total FGD Power Consumption	2,044	2,695	1,680	3,747
Fixed O&M Costs				
Number of Operators (40 hrs/week)	16	18	14	21
Operating Labor Cost **	$969,047	$1,126,368	$863,382	$1,315,305
Maint. Labor & Matls. Cost	$3,300,698	$3,697,829	$3,296,106	$4,157,723
Admin. & Support Labor	$686,798	$781,650	$654,547	$893,518
TOTAL	$4,956,542	$5,605,847	$4,814,036	$6,366,547
Variable Operating Costs **				
Reagent Costs	$391,998	$516,847	$394,136	$718,619
Disposal Costs	$1,598,080	$2,107,058	$1,606,794	$2,929,631
Credit for Byproduct	$0	$0	$0	$0
Steam Costs	$0	$0	$0	$0
Fresh Water Costs	$2,861	$3,772	$2,877	$5,245
Power Costs	$246,200	$324,613	$202,356	$451,338
TOTAL	$2,239,139	$2,952,290	$2,206,163	$4,104,833

** *These costs assume inputs are in current dollars (no escalation included).*

TOTAL OPERATING COSTS	***$7,195,682***	***$8,558,136***	***$7,020,198***	***$10,471,380***

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

Fabric Filter Baghouse		RR Unit 2	RR Unit 3	TC High	TC Unit 9
Flue Gas, Upstream of Fabric Filter					
Temperature	°F	300	300	300	300
Pressure	in. H2O	-12	-12	-12	-12
Flow Rate	SCFM	748,881	987,395	752,965	1,372,863
Flow Rate	ACFM	1,148,302	1,514,029	1,154,564	2,105,090
CO2	lb/hr	642,148	846,668	645,650	1,177,198
N2	lb/hr	2,339,668	3,084,836	2,352,426	4,289,124
SO2	lb/hr	2,703	3,563	2,717	4,954
O2	lb/hr	187,835	247,660	188,860	344,343
HCl	lb/hr	38	50	38	69
Other Gases	lb/hr	817	1,077	821	1,497
H2O	lb/hr	258,299	340,565	259,707	473,518
Fly Ash	lb/hr	16,263	21,443	16,352	29,814
Total (gas only)	lb/hr	3,431,507	4,524,418	3,450,218	6,290,704
Total Fabric Required	Ft^2	328,086	432,580	329,875	601,454
Surface Area per Bag	Ft^2	31.4	31.4	31.4	31.4
Required No. of Bags (no spare compartments)		10,443	13,769	10,500	19,145
Final No. of Bags		11,488	15,146	11,550	21,059
No. of Casings		1	1	1	2
Fabric Filter Dimensions (per Casi	Ft^2	11,278	14,870	11,339	10,337
Length	Ft	150	172	151	144
Width	Ft	75	86	75	72

Attachment 1.

CUECost - Air Pollution Control Systems Spreadsheet

Fabric Filter Baghouse		RR Unit 2	RR Unit 3	TC High	TC Unit 9
Capital Cost		Case 1	Case 2	Case 3	Case 4
Cost Basis (Year)		***2013***	***2013***	***2013***	***2013***
Fabric Filter	$	$7,126,070	$8,668,846	$7,153,590	$13,399,123
Bags	$	$926,147	$1,221,118	$931,197	$1,697,830
Ash Handling System	$	$629,314	$723,500	$630,926	$875,717
ID Fan(s)	$	$912,055	$1,082,304	$915,130	$1,327,244
Equipment Cost Subtotal	$	$9,593,586	$11,695,768	$9,630,844	$17,299,914
Instruments & Controls	$	$191,872	$233,915	$192,617	$345,998
Taxes	$	$575,615	$701,746	$577,851	$1,037,995
Freight	$	$479,679	$584,788	$481,542	$864,996
Purchased Equipment Cost Subt	$	$10,840,752	$13,216,218	$10,882,854	$19,548,903
Installation	$	$7,263,304	$8,854,866	$7,291,512	$13,097,765
Total Direct Cost	$	$18,104,055	$22,071,084	$18,174,365	$32,646,668
Total Direct Cost with Retrofit F	$	$39,828,922	$48,556,385	$39,983,604	$71,822,671
General Facilities	$	$3,982,892	$4,855,638	$3,998,360	$7,182,267
Engineering Fees	$	$3,982,892	$4,855,638	$3,998,360	$7,182,267
Contingency	$	$7,965,784	$9,711,277	$7,996,721	$14,364,534
Total Plant Cost (TPC)	$	$55,760,490	$67,978,939	$55,977,045	$100,551,739
Total Plant Cost (TPC) w/ Prime C	$	$57,433,305	$70,018,307	$57,656,357	$103,568,291
Total Cash Expended (TCE)	$	$56,596,898	$68,998,623	$56,816,701	$102,060,015
Allow. for Funds During Constr. (A	$	$3,011,066	$3,670,863	$3,022,760	$5,429,794
Total Plant Investment (TPI)	$	$59,607,964	$72,669,485	$59,839,462	$107,489,809
Preproduction Costs	$	$1,192,159	$1,453,390	$1,196,789	$2,149,796
Inventory Capital	$	$0	$0	$0	$0
TOTAL CAPITAL REQUIREMEN	***$***	***$60,800,123***	***$74,122,875***	***$61,036,251***	***$109,639,605***
	$/kW	$208.2	$192.5	$254.3	$204.8

O&M Data and Costs		Case 1	Case 2	Case 3	Case 4
Cost Basis (Year)		***2013***	***2013***	***2013***	***2013***
Power Required Excluding ID F	kW	493	644	496	885
ID Fan Power for FF Delta P	kW	1,160	1,529	1,166	2,126
Total Power	kW	1,653	2,173	1,662	3,011
Power Cost **	$/yr	$199,076	$407,746	$311,828	$565,011
Maintenance Costs	$/yr	$1,267,284	$1,544,976	$1,272,206	$2,285,267
Periodic Replacement Items	$/yr	$926,147	$1,221,118	$931,197	$1,697,830
First Year Cost. Bags Replaced Every		*5 Years*	*5 Years*	*5 Years*	*5 Years*
TOTAL OPERATING COSTS		***$2,392,507***	***$3,173,840***	***$2,515,230***	***$4,548,108***

** *These costs assume inputs are in current dollars (no escalation included).*

Reasonably Available Control Technology

EES Coke Battery, LLC

EES Coke Battery, LLC
River Rouge, Michigan

March 31, 2014

EXECUTIVE SUMMARY

EES Coke Battery, LLC (EES Coke) is submitting a Reasonably Achievable Control Technology (RACT) analysis for its existing coke battery located on Zug Island, River Rouge, Michigan. This analysis has been requested by the Michigan Department of Environmental Quality (MDEQ) as part of its effort to develop a State Implementation Plan (SIP) to achieve compliance with the 1-hr SO_2 National Ambient Air Quality Standard (NAAQS) in the newly designated non-attainment area in Wayne County. EES Coke's RACT analysis evaluates both flue gas and Coke Oven Gas (COG) desulfurization. Flue gas desulfurization is determined to be technically infeasible at EES Coke's natural draft battery. COG desulfurization is determined to be economically infeasible costing $14,002 per ton of SO_2 removed and slightly over $1.75 million per ppb of ambient concentration reduced.

EES Coke does not cause a violation of the NAAQS at either the Southwest High School ambient monitor or at its point of highest ambient impact (i.e., hot spot), even when all the coke oven gas generated by the battery is consumed in EES Coke combustion sources (Underfire and COG Flare). Further, EES Coke's ambient impacts are relatively insignificant compared to other nearby sources. EES Coke is not the cause of the nonattainment status for the area and should not be the focus of the mitigating measures.

1.0 INTRODUCTION

EES Coke Battery, LLC (EES Coke) is submitting a Reasonably Achievable Control Technology (RACT) analysis for the existing coke battery facility located at 1400 Zug Island Rd., River Rouge, Michigan. EES Coke is located in the newly designated non-attainment area which encompasses a portion of in Wayne County, which is currently in attainment with all National Ambient Air Quality Standards (NAAQS), with the exception of the 2010 primary sulfur dioxide (SO_2) NAAQS. U.S. Environmental Protection Agency (EPA) designated the area nonattainment for SO_2 on October 4, 2013. The Clean Air Act (CAA) directs areas designated nonattainment (i.e., failing to meet the NAAQS) to undertake certain planning and pollution control activities to attain the NAAQS as expeditiously as practicable. Thus, as part of Michigan's State Implementation Plan (SIP), which must provide for attainment of the SO_2 NAAQS, Michigan Department of Environmental Quality (MDEQ) has requested that EES Coke submit a RACT analysis for SO_2 emissions.

U.S. EPA defines RACT as:

> *The lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility (44 FR 53762).*

1.1 Process Description

The EES Coke No. 5 Coke Battery produces coke from the heating of metallurgical coal, in the absence of oxygen, to vaporize volatile constituents and concentrate the carbon. The coke is used as a raw material in a blast furnace to produce iron. EES Coke operates one (1) coke battery consisting of eighty-five (85), six (6)-meter high ovens that produce coke. The ovens are situated in rows and enclosed between heating walls. The ovens are equipped with four (4) lids on the top of each oven and doors on the two (2) external sides that do not face neighboring ovens. During the "charging" step, coal is taken from storage bins and loaded into a "larry car." The larry car then moves to the empty oven where it unloads coal into the oven. The coal is leveled in the oven using a leveling bar to create a space for waste gas to collect and be drawn off the coal mass undergoing "coking." The coal within each oven is heated for approximately 17-18 hours, in the absence of oxygen, by means of underfire combustion to a temperature of around 1,800-2,200 °F, until the volatile matter, water, and coal-tar in the coal mass are vaporized and driven off. This volatile matter leaves the battery oven as raw coke oven gas (COG) and is sent to the No. 3 By-products Plant for further processing. In order to minimize emissions, staged heating and recirculation flow technologies are utilized on the No. 5 Coke Battery.

Following the "coking" process, both doors are removed and a pushing machine pushes the coke out of the oven into a quench car. Fugitive emissions from the quench car are collected and exhausted through the Pushing Emission Control System (PECS) Baghouse. The quench car is moved along the length of the battery, until it reaches the quench tower where it is quenched with water to cool the coke prior to screening and shipment of the coke.

The No. 3 By-products Plant refines the raw COG and separates tars and light oils by passing the raw gas and process fluids through a series of process decanters, condensers, heat exchangers, and stills. The conditioned COG is then used as a fuel to heat the coke battery, a portion is sent to U.S. Steel for use in several processes, and a portion is sold to offsite sources. Excess COG is flared in an open flare located adjacent to the battery.

1.2 Significant Sources of Sulfur Dioxide (SO_2) Emissions

Coke is produced from the heating of metallurgical coal, in the absence of oxygen, to vaporize volatile constituents and concentrate the carbon. A by-product of the process is coke oven gas (COG), which is recovered in the by-products plant, cleaned, and used as a fuel for heating the ovens. SO_2 is emitted from underfire combustion as a result of the thermal oxidation of the sulfur compounds in the fuel. EES Coke currently collects fuel samples to determine the hydrogen sulfide (H_2S) content of the COG and operates a continuous emissions monitoring system (CEMS) for SO_2 to demonstrate continuous compliance with the current permit emission limits.

In addition to SO_2 emissions from underfire combustion, SO_2 is emitted from combustion of excess COG in the COG flare (worst-case Battery Underfire and Flare SO2 emissions total 3,846 tpy). The COG flare is a control device used to combust COG that is not used to underfire the battery, used at other on-site sources, or sold offsite.

These EES Coke emissions sources do not cause a violation of the NAAQS at either the Southwest High School (SWHS) ambient monitor or at their point of highest ambient impact (i.e., hot spot). The maximum ambient 1-hr SO2 concentration resulting from EES Coke emission sources is 26 ppb, approximately one-third of the 75 ppb NAAQS. At 17.8 ppb, EES Coke's maximum impact at the SWHS monitor is less than one-quarter of the NAAQS, and only slightly greater than the prevailing background SO2 concentration of 15 ppb. Further, EES Coke's ambient impacts are insignificant compared to other nearby sources. It should be noted when EES Coke sources are modeled in combination with other sources in the area, EES's contribution to the overall ambient impact is minimal as the maximum impact is the result of other nearby sources. EES Coke's emissions do not cause a violation of the NAAQS.

Although SO_2 can be controlled in various types of combustion sources using several techniques, there are considerable limitations associated with retrofitting emission controls on an existing coke battery. Since the coke oven operates at temperatures in excess of 1,800°F and cannot be cooled once operation begins, the logistics of any retrofit project are very difficult to arrange. In addition, because EES Coke is a natural draft combustion source, the addition of post-combustion controls generally requires a complete rebuild of the facility.

The following section contains a RACT analysis for emissions of SO_2 at the No. 5 Coke Battery and No. 3 By-products Plant.

2.0 CONTROL TECHNOLOGY REVIEW

As outlined in Section 1.0, EES Coke is submitting a RACT analysis for the existing coke battery facility as requested by MDEQ. The following sections outline this control technology analysis.

2.1 Reasonably Achievable Control Technology (RACT) Analysis

RACT is defined by U.S. EPA as:

> *The lowest **emission limitation** that a particular source is capable of meeting by the application of control technology that is **reasonably available** considering **technological** and **economic feasibility** (44 FR 53762). [emphasis added]*

This RACT analysis is broken down into five (5) steps. The steps coincide with the definition of RACT:

1. Identify All Reasonably Available Control Technologies;
2. Evaluate All Control Technologies and Eliminate All Technologically Infeasible Options;
3. Discuss Remaining Control Technologies;
4. Evaluate Remaining Control Technologies Based on Economic Feasibility; and
5. Propose RACT Emission Limit.

EES Coke has reviewed current permits for coke ovens, and other relevant information, for comparison to the emission limits proposed as RACT for this project. It is important to note that coke oven emissions can vary considerably based on the equipment technology and the age of the process equipment. The majority of recently permitted coke batteries are of the heat recovery variety. This technology oxidizes all of the volatiles emitted from the ovens, rather than recovering useful byproducts downstream. Oven design between the two technologies differs greatly as heat recovery ovens are kept at negative pressure, and by-products recovery ovens are kept at positive pressure. Since the EES Coke battery is of the by-product recovery type, emission rates are not easily comparable; therefore this RACT review incorporates only the control technologies applicable to a by-product recovery coke battery.

The sections that follow provide detailed RACT analyses for SO_2 emissions from EES Coke.

2.1.1 Identify All Reasonably Available Control Technologies – STEP 1

Control options for SO_2 consist of pre-combustion COG desulfurization and post-combustion flue gas desulfurization. The only emissions reduction alternative at a flare is to minimize the sulfur content of the waste gases being flared (i.e., COG desulfurization).

Potential SO_2 control technologies are as follows:

Underfire Combustion

1. Flue Gas Desulfurization
2. COG Desulfurization

COG Flare

1. COG Desulfurization

2.1.2 Eliminate Technologically Infeasible Options – STEP 2

The following technologies are considered to be technically infeasible for operation at the EES Coke by-products recovery coke battery plant and are therefore eliminated from further review.

Flue Gas Desulfurization (FGD) **-** Flue gas desulfurization (FGD) is a post-combustion control technology that uses a scrubbing media to absorb SO_2 present in the exhaust gas stream. FGD is most often used to control emissions from coal-fired boilers. Traditionally designed as a wet system, FGD uses a scrubbing liquid containing an alkali reagent such as lime or limestone for the absorption of SO_2. Exhaust gas enters the absorber and travels up through the absorption zone where it contacts the absorbent slurry or solution that is passing down through the absorber. SO_2 dissolves into the slurry where it reacts with the alkaline reagent. Treated exhaust gas then passes through a mist eliminator to remove any entrained slurry droplets before exiting the absorber. The process can be regenerative (slurry is recycled back into the system) or non-regenerative (slurry is disposed of or used as a by-product).

The installation of a FGD system would require redesigning and reconstructing the facility in a manner never attempted for any by-products recovery coke battery. The EES Coke battery and other by-products recovery coke batteries rely on natural draft to draw air into the combustion system for proper operation. FGD necessarily quenches the flue gas with sprays to capture SO2. This cooling of the gas would greatly diminish this natural draft and in turn compromise the combustion system. For this reason we consider this alternative to be technically infeasible.

2.1.3 Discussion of Technologically Feasible Options – STEP 3

The only technologically feasible control option for reducing SO_2 emissions due to COG combustion in the battery underfire or flare is COG desulfurization.

COG Desulfurization **-** COG desulfurization involves chemical and physically treating the COG to remove sulfur prior to combustion. COG desulfurization requires the design and construction of a major chemical facility to handle the volumes of COG generated at EES Coke.

2.1.4 Evaluate Remaining Control Technologies based on Economic Feasibility – STEP 4

COG desulfurization is the only technologically feasible and available control option for minimizing SO_2 emissions at the EES Coke battery underfire and flare. However, implementing a COG sulfur reduction strategy would require excessive economic costs, beyond what is required by RACT and especially when the source is not causing a NAAQS violation at the SWHS monitor or at its own point of maximum impact (hot spot). The economic feasibility of COG desulfurization is outlined below.

COG Desulfurization

Capital Costs - EES Coke solicited JNE Consulting and Engineering ("JNE") for a preliminary COG desulfurization budgetary cost estimate specific to EES Coke's operating parameters. These parameters included COG production rates consistent with the maximum dry coal charge with sufficient short-term over-capacity to account for upset conditions, reduced efficiency over time, and allowable sulfur content of COG. Costs for infrastructure support facilities as well as modification costs that would be incurred from upgrades at the waste water treatment plant were included in this analysis.

JNE's 2013 estimate was $111.9 million but excluded certain indirect costs and interest during construction. EES Coke has adjusted the capital estimate at 2.5% annually to convert it into 2015 dollars, added interest during construction, and added 25% to cover certain indirect costs not included in the JNE estimate and contingency. Note: this estimate does not include costs associated with potential lost production. See Appendix B for details.

Operating Costs - COG desulfurization operating expenses were estimated by internal engineers located at the EES Coke battery. Average annual operating costs are estimated to be approximately $25.1 million and are generally inflated annually at 2.5%. See Appendix A for details.

Cost of Capital - In order to annualize the capital costs associated with the investment, EES Coke calculated a capital recovery factor assuming a 15 year project life and a 7% interest rate. The capital recovery factor was calculated to be 0.1098, resulting in annual capital recovery costs of approximately $18.0 million.

Tons of SO2 Removed - EES Coke has the capacity to generate up to approximately 3,846 tons of SO2 annually (2,568 from underfire and 1,278 from flare). Assuming a 90% removal efficiency and 89% up-time, 3,082 tons of SO2 is expected to be removed as a result of the COG desulfurization investment. The estimated dollar per ton removal cost of COG desulfurization is estimated to be $14,002 per ton. See Appendix A for details.

2.1.5 Propose RACT Emission Limit – STEP 5

The proposed RACT emission limits and/or work practice standards are discussed in this section for the EES Coke battery.

COG Combustion –SO_2 Emission Limit

RACT for emissions of SO_2 from EES Coke is determined to be continued compliance with the existing emission limits for the coke oven battery underfire. There are no additional technologically or economically feasible control options reasonably available for SO_2 reduction at EES Coke.

Appendix A

COG Desulfurization Control Costs	
Operating Costs ($000's)	
Variable Costs:	
Steam (500,000 mmlbs/yr)	$4,258
Electricity (29,000 mwh/yr)	3,425
Nitrogen (400,000 ccf/yr)	86
Service Water (31,500 mgal/yr)	43
Caustic Soda (1,400 tons/yr)	1,100
	$8,911
Fixed Costs:	
Sewer	$517
Annual Maintenance	2,248
Labor	923
Administrative Charges (2% of Capital Investment)	3,291
Property Taxes (1% of Capital Investment)	1,646
Insurance (1% of Capital Investment)	1,646
Overhead (60% of Labor and Materials)	5,901
	$16,172
Total Operating Costs:	**$25,083**
Capital Recovery ($000's)	**$18,068**

COG Desulfurization SO2 Removal	
Annual Production (tons dry coal charged (000's)	1,365
COG Generation (mmBtu/ton dry coal)	7.25
COG Heat Content (Btu/scf)	500
COG Sulfur Content (grains H2S/scf)	2.64
Annual Underfire COG Consumption (mmBtu)	3,617,250
Annual Flare COG consumption (mmBtu)	1,800,000
Uncontrolled SO2 Emissions (tons/yr)	3,846
SO2 Removal Rate	90%
Annual Desulf Facility Outage Days	40
Facility Availability	89%
Controlled SO2 Emissions (ton/yr)	3,082

COG Desulfurization Control Costs	
Total Annualized Costs ($000's)	$43,151
Annual SO2 Removed (tons)	3,082
Control Costs ($/ton)	**14,002**

Appendix B

EES Coke

Desulfurization Total Project Summary

Funding Request Installation Cost Estimate

Work Breakdown Structure

Project Direct Costs	**Process Equipment**	**Engrd Equip - Elect**	**Engr Equip - Mech**	**Instrumentation**	**Engr Equip - PC / Auto**	**Installation**		**Total**
Primary Cooling	$ 2,819,000	$ -	$ -	$ 601,000	$ -	$ 10,370,000		$ 13,790,000
Cooling Water System	$ 3,385,200	$ 970,000	$ -	$ 84,000	$ 615,000	$ 17,230,000		$ 22,284,200
Scrubbing	$ 1,487,000	$ -	$ -	$ 197,000	$ -	$ 5,595,000		$ 7,279,000
Distillation	$ 3,647,600	$ 90,000	$ -	$ 337,000	$ -	$ 11,745,000		$ 15,819,600
Sulfur Recovery Units	$ 4,255,800	$ 580,000	$ -	$ 733,000	$ -	$ 15,125,000		$ 20,693,800
Power	$ -	$ 680,000	$ -	$ -	$ -	$ 5,095,000		$ 5,775,000
Automation	$ -	$ -	$ -	$ -	$ -	$ -		$ -
BioPlant	$ 1,101,000	$ -	$ -	$ -	$ -	$ 2,500,000		$ 3,601,000
Sub-Total Project Direct Costs	$ 16,695,600	$ 2,320,000	$ -	$ 1,952,000	$ 615,000	$ 67,660,000	$ -	$ 89,242,600

Project Indirect Costs								**Total**
Indirect Costs								$ 22,682,540

Total Project								**$ 111,925,140**

2 Years of Inflation	5,666,210
Other Indirect Costs + Contingency	29,397,838
Interest During Construction	17,575,545
Total Capital Investment Used in RACT Analysis	**$ 164,564,733**