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July 26, 2017

Mr. John Jenks Environmental Engineer Utah Division of Air Quality 195 North 1950 West P. O. Box 144820 Salt Lake City, Utah 84114-4820 Document Date: 07/26/2017

DAQ-2017-011661

RE: Addendum - Best Available Control Measure Analyses for HollyFrontier's Woods Cross Refinery

Dear Mr. Jenks:

Please find in this addendum to the Best Available Control Measure (BACM) Analyses prepared for HollyFrontier's Woods Cross Refinery the additional information requested by the Utah Division of Air Quality (UDAQ) on June 28, 2017. In this request, three areas were indicated where additional information was needed. These areas were: (1) economics and selection of BACM; (2) lack of additional feasible measures/most stringent measures, and (3) individual issues.

Economics and Individual Issues

The economic evaluations presented in the BACM analysis for HollyFrontier were based on potential to emit (PTE) emissions for refinery sources utilizing permit conditions, permit emission factors and permit limitations. The quantities of emission reductions provided in the analyses were based on the estimated control that would be achieved with the application of a control technology (such as more efficient burners or add-on devices) and the difference between the current PTE emissions without that control technology and future estimated emissions after the application of a control technology. Since detailed engineering designs and associated vendor costs for plant modifications that would be needed for the application of a control technology were not available, due to the short response time, generalized control efficiencies, obtained from published literature and EPA guidance were used to estimate the potential control efficiencies or emission reductions that are associated with the application of a control technology.

Cost estimates that were provided in the BACM analyses were based on information obtained from vendors, economic information provided by HollyFrontier from the purchase and installation of similar equipment, or information as found in EPA guidance documentation. The \$/ton threshold that was used by HollyFrontier to indicate whether the application of a control technology was economically feasible ranged from \$15,000 to \$20,000 depending on pollutant and emission unit.

Per UDAQ's additional information request to HollyFrontier, replacement costs for the emergency engines were obtained from Wheeler Machinery and the economic viability of replacing Tier 2 or older equipment with newer Tier 3 or 4 diesel engines was examined. Per Wheeler Machinery, the estimated cost to replace a 200HP or 400HP engine with a newer engine was \$75,000 and \$115,000, respectively. This cost is for equipment only and doesn't include engineering or installation costs. The economic viability analysis for replacing Tier 2 or older diesel engines at HollyFrontier is presented in Attachment 1. According to the analysis in Attachment 1, it would be not be economically viable for HollyFrontier to replace existing engines with Tier 3 or Tier 4 engines.

In order to further clarify the BACM and economic analysis for heater controls, as stated in HollyFrontier's BACM analyses, the application of low NO_x burners (LNB) or ultra low NO_x burners (ULNB) on existing units (6H1, 6H2, 6H3, 7H1, 7H2, 7H3, 9H1, 9H2, 10H1, 11H1, and 13H1) was not technically possible due to space limitations in the firebox, lower heat duty, and a longer flame. In addition, in order to use a selective catalytic reduction (SCR) system on process heaters at HollyFrontier, the refinery would need to replace all naturally draft heaters with mechanical draft heaters. Only 6H1 is mechanically drafted.

The economic feasibility of converting the above list of heaters to mechanical draft and then reducing NO_x emissions through the addition of SCR was examined. The cost guidance information provided in EPA-453/R-93-034 Alternative Control Techniques Document- NO_x Emissions from Process Heaters (Revised) was used for this analysis. The 1991 capital costs were escalated to average 2017 dollars using the Chemical Engineering plant index. The results of this analysis are presented in Table 1 and in Attachment 2.

Table 1 Economic Viability to Convert Natural Draft to Mechanical Draft Process Heaters with Application of SCR

Unit	Rating MMBtu/hr	\$/ton NO _x
6H1 ¹	54.7	\$ 80,097
6H2	12.0	\$ 170,826
6H3	37.7	\$ 107,763
7H1	4.4	\$ 255,031
7H3	33.3	\$ 113,666
9H1	8.1	\$ 199,858
9H2	4.1	\$ 262,329
10H1	13.2	\$ 164,447
11H1	24.2	\$ 129,106
13H1	6.5	\$ 218,220

¹ Application of SCR only.

The results of Table 1 indicate that it is not economically feasible to convert the listed process heaters from natural draft and then apply a SCR to reduce NO_x emissions. Thus, for technical and economic reasons, no control technology modifications are proposed by HollyFrontier on these units.

Lack of Additional Feasible Measures/Most Stringent Measures

In the UDAQ's original request for BACM/BACT, the January letter indicated that "Should the area not be able to meet the PM_{2.5} standards by the statutory Serous Area attainment date (December 31, 2019), whether by modeled prediction or actual ambient monitoring, the standard of control measure feasibility would rise once more to what are called Most Stringent Measures (MSM)". In HollyFrontier's BACM analyses, most stringent measures (MSM) were identified and included in the selection of BACM. However, at this time, HollyFrontier does not believe that providing additional MSM analysis is appropriate since nonattainment has not been demonstrated/modeled.

Other Individual Issues

Presented in Attachment 3 are the monitoring recommendations and emission limitations for emission sources at HollyFrontier.

If you have any questions or concerns regarding the information in this letter, please feel free to contact HollyFrontier.

Sincerely,

MSI TRINITY CONSULTANTS

Linda Conger

Managing Consultant

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ATTACHMENT 1

Economic Viability Analysis for Diesel Engine Replacement

Cost to Replace Tier 2 or older Emergency Diesel Engines with Tier 4 Units HollyFrontier Woods Cross Refinery

						Uncontrolled (Tier 1)		Unco	Uncontrolled (Tier 4) Emission Reduc				ction	cion Cost Effectiveness				
	Year	Rating	Rating	Re	placement	PM _{2.5} PTE	NO_X PTE	VOC PTE	PM _{2.5} PTE	NO_X PTE	VOC PTE	$\mathrm{PM}_{\mathrm{2.5}}\mathrm{PTE}$	NO_X PTE	VOC PTE		(\$	(ton)	
Diesel Emergency Equipment	Built	(HP)	(KW)		Cost	TPY	TPY	TPY	TPY	TPY	TPY	TPY	TPY	TPY		PM _{2.5}	NO _x	voc
224 HP (water well #3)	2002	224.0	167.0	\$	75,000	0.0049	0.085	0.0123	0.0002	0.004	0.00172	0.005	0.081	0.011	\$	15,812,110 \$	922,373	\$ 7,078,677
393 HP Fire Pump #1	1982	393.0	293.1	\$	115,000	0.0086	0.149	0.0216	0.0003	0.006	0.00303	0.008	0.143	0.019	\$	13,819,167 \$	806,118	\$ 6,186,488
393 HP Fire Pump #2	1982	393.0	293.1	\$	115,000	0.0086	0.149	0.0216	0.0003	0.006	0.00303	0.008	0.143	0.019	\$	13,819,167 \$	806,118	\$ 6,186,488
220 HP plant air backup compressor #1	1997	220.0	164.1	\$	75,000	0.0048	0.083	0.0121	0.0002	0.004	0.00169	0.005	0.080	0.010	\$	16,099,603 \$	939,144	\$ 7,207,380
220 HP plant air backup compressor #2	1997	220.0	164.1	\$	75,000	0.0048	0.083	0.0121	0.0002	0.004	0.00169	0.005	0.080	0.010	\$	16,099,603 \$	939,144	\$ 7,207,380
220 HP plant air backup compressor #3	<2000	220.0	164.1	\$	75,000	0.0048	0.083	0.0121	0.0002	0.004	0.00169	0.005	0.080	0.010	\$	16,099,603 \$	939,144	\$ 7,207,380
380 HP diesel generator (central control room)	1997	380.0	283.4	\$	115,000	0.0084	0.144	0.0209	0.0003	0.006	0.00293	0.008	0.138	0.018	\$	14,291,928 \$	833,696	\$ 6,398,131

Assumptions:

Cost estimate for engine only provided by Wheeler Machinery. Cost does not include engineering or installation costs. PTE emissions based on 50 operating hours per year and Title V permit application

ATTACHMENT 2

Economic Viability to Convert Natural Draft to Mechanical Draft Process Heaters with Application of SCR

HollyFrontier BACM Analysis - Cost to Convert from Natural Draft to Mechanical Draft

				Cost to Convert from ND to MD							
HollyFrontier Source ID	Source Description	MMBtu/hr	GJ/hr	Capital Cost to Convert from ND to MD 1991\$	Capital Cost 2017\$	Capital Recovery Factor	Capital Recovery	O&M Cost	Total Annual Cost	SCR Capitol Cost (1991\$)	SCR Cost (2017\$)
6H1	Reformer Reheat Furnace	54.7	57.7	243,313.6	416,247.8	0.131	54,725.67	11,446.81	66,172.49	1,481,294	2,534,117
6H2	Prefractionator Reboiler Heater	12.0	12.7	97,922.6	167,520.6	0.131	22,024.57	4,606.82	26,631.39	595,141	1,018,135
6H3	Reformer Reheat Furnace	37.7	39.8	194,616.1	332,938.8	0.131	43,772.72	9,155.82	52,928.53	1,184,212	2,025,886
7H1	HF Alkylation Regeneration Furnace	4.4	4.6	53,634.7	91,755.3	0.131	12,063.42	2,523.27	14,586.69	325,754	557,283
7H3	HF Alkylation Depropanizer Reboiler	33.3	35.1	180,651.1	309,048.1	0.131	40,631.72	8,498.82	49,130.55	1,099,065	1,880,221
9H1	DHDS Reactor Charge Heater	8.1	8.5	77,350.8	132,327.6	0.131	17,397.61	3,639.01	21,036.62	469,974	804,005
9H2	DHDS Stripper Reboiler	4.1	4.3	51,409.6	87,948.8	0.131	11,562.96	2,418.59	13,981.55	312,228	534,143
10H1	Asphalt Mix Heater	13.2	13.9	103,685.6	177,379.7	0.131	23,320.78	4,877.94	28,198.72	630,217	1,078,140
11H1	SRGP Depentanizer Reboiler	24.2	25.5	149,163.7	255,181.3	0.131	33,549.64	7,017.48	40,567.13	907,166	1,551,931
13H1	Isomerization Reactor Feed Furnace	6.5	6.9	67,783.2	115,959.8	0.131	15,245.68	3,188.90	18,434.57	411,781	704,453

Assumptions:

Cost estimates based on guidance as found in EPA-453/R-93-034, Alternative Control Techniques Document - NOx Emissions from Process Heaters (Revised)

Capitol Cost model for ND-to-MD conversion is: TIC = $21350 (HQ)^0.6$ where HQ is heater capacity in GJ/hr.

Capitol recovery based on pretax marginal rate of return (10 percent) and equipment economic life of 15 years

Maintenace costs associated with ND-to-MD Conversion are estimated as 2.75 percent of the ND-to-MD capitol cost

HollyFrontier Costs to Upgrade Process Heaters to Mechanical Draft then Add SCR

Unit	Rating	Baseline Emis	sion Factor	SCR Emissi		
	MMBtu/hr	(lb/MMBtu)	NO _x (TPY)	(lb/MMBtu)	NO _x (TPY)	\$/ton
6H1	54.7	0.098	23.49	0.025	5.87	\$ 80,097
6H2	12.0	0.098	5.15	0.025	1.29	\$ 170,826
6H3	37.7	0.098	16.19	0.025	4.05	\$ 107,763
7H1	4.4	0.098	1.89	0.025	0.47	\$ 255,031
7H3	33.3	0.098	14.30	0.025	3.57	\$ 113,666
9H1	8.1	0.098	3.48	0.025	0.87	\$ 199,858
9H2	4.1	0.098	1.76	0.025	0.44	\$ 262,329
10H1	13.2	0.098	5.67	0.025	1.42	\$ 164,447
11H1	24.2	0.098	10.39	0.025	2.60	\$ 129,106
13H1	6.5	0.098	2.79	0.025	0.70	\$ 218,220

Assumptions:

Cost estimates based on methodologies found in EPA-453/R-93-034 Alternative Control Techniques Document - NOx emissions from Process Heaters (Revised)
Convert from natural draft to mechanical draft
Cost includes addition of SCR

$\mathrm{NO_x}$ Cost Analysis to Upgrade Process Heaters and Add SCR - 6H1

		MD/SCR	Factor	Basis for Cost
		Upgrade		and Factor
Direct Costs:				
Puchased Equipment:				
Primary and Auxiliary Equipment (PE)	\$	2,534,117	Include co	osts add SCR since MD already
Sales Tax	\$	152,047	6% of PE	OTC-LADCO 2008
Freight	\$	126,706	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$	2,812,870		
Direct Installation				
Electrical, Piping, Insulation and Ductwork	\$	1,125,148	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$	1,125,148		
Total Direct Cost (DC)	\$	3,938,018		
Indirect Installation Costs				
Engineering and Project Management,	1			
Construction and Field Expenses, Contractor				
Fees, Startup Expenses, Performance Tests,				
Contingencies	\$	1,715,851	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$	1,715,851		
Total Installed Cost (TIC)	\$	5,653,868		
NO _x Emissions Before Control, lb/MMBtu	٦	0.098		
NO _x Emissions Before Control, tn/yr		23.48		
NO _x Emissions After Control, lb/MMBtu		0.0245		
Control Efficiency (%)		75		
NO _x Emissions After Control, tn/yr		5.87		
NO _x Emission Reduction, tn/yr		17.61		
Annual Casta Character (Director Indiana)				
Annual Costs, \$/year (Direct + Indirect) Direct Costs				
Operating Labor	\$	160 616	3% of capitol (cost
Raw materials	\$	109,010	370 Of Capitor	
Replacement Parts	\$	169 616	3% of capitol (rost
Total Direct Costs, \$/year	\$	339,232	370 Of Capitor	2031
Indianat Costs				
Indirect Costs Overhead	\$	101 770	60% of labors	L costs
Overhead Tayor Insurance and Administration	\$		60% of labor of 4% of total ins	
Taxes, Insurance, and Administration Capitol Recovery	\$		10%, 15 years	
	\$ \$		10/0, 13 years	, CM1314/
Total Indirect Costs, \$/year Total Annual Cost	\$	1,071,238 1,410,471		
Cost Effectiveness, \$ per ton NO _x reduction	+			
cost effectiveness, φ per ton NO _x reduction	\$	80,096.82		

Assumptions:

$\mathrm{NO_x}$ Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 6H2

	MD/SCR		Factor	Basis for Cost			
		Upgrade		and Factor			
Direct Costs:							
Puchased Equipment:							
Primary and Auxiliary Equipment (PE)	\$	1,185,656	Include cos	ts to convert to MD and add SCR			
Sales Tax	\$	71,139	6% of PE	OTC-LADCO 2008			
Freight	\$	59,283	5% of PE	OTC-LADCO 2008			
Total Purchased Equipment Cost (PEC)	\$	1,316,078					
Direct Installation							
Electrical, Piping, Insulation and Ductwork	\$	526,431	40% of PEC	OTC-LADCO 2008			
Total Direct Installation (DI)	\$	526,431					
Total Direct Cost (DC)	\$	1,842,509					
Indirect Installation Costs							
Engineering and Project Management,							
Construction and Field Expenses, Contractor							
Fees, Startup Expenses, Performance Tests,							
Contingencies	\$	802,808	61% of PEC	OTC-LADCO 2008			
Total Indirect Cost	\$	802,808	01/0 011 20	0.10 12 12 00 1200			
	Ť	<u> </u>					
Total Installed Cost (TIC)	\$	2,645,317					
NO _x Emissions Before Control, lb/MMBtu		0.098					
NO _x Emissions Before Control, tn/yr		5.15					
NO _x Emissions After Control, lb/MMBtu		0.025					
Control Efficiency (%)		75					
NO _x Emissions After Control, tn/yr		1.29					
NO _x Emission Reduction, tn/yr		3.86					
Annual Costs, \$/year (Direct + Indirect)	-						
Direct Costs	<u>,</u>	70.260	20/ -f:				
Operating Labor	\$ \$	79,360	3% of capitol of	COST			
Raw materials	\$	70.260	3% of capitol of				
Replacement Parts Total Direct Costs, \$/year	\$	79,360 158,719	5% Of Capitor (l			
Total Direct Costs, 3/ year	Ş	150,/15					
Indirect Costs							
Overhead	\$		60% of labor of				
Taxes, Insurance, and Administration	\$	•	4% of total ins				
Capitol Recovery	\$		10%, 15 years	, CRF13147			
Total Indirect Costs, \$/year	\$	501,208					
Total Annual Cost	\$	659,927					
Cost Effectiveness, \$ per ton NO _x reduction	\$	170,825.76					

Assumptions:

$\mathrm{NO_x}$ Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 6H3

	MD/SCR		Factor	Basis for Cost
		Upgrade		and Factor
Direct Costs:				
Puchased Equipment:				
Primary and Auxiliary Equipment (PE)	\$	2,349,825	Include cos	its to convert to MD and add SCR
Sales Tax	\$	140,990	6% of PE	OTC-LADCO 2008
Freight	\$	117,491	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$	2,608,306		
Direct Installation				
Electrical, Piping, Insulation and Ductwork	\$	1,043,322	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$	1,043,322		
Total Direct Cost (DC)	\$	3,651,628		
Indirect Installation Costs				
Engineering and Project Management,	1			
Construction and Field Expenses, Contractor				
Fees, Startup Expenses, Performance Tests,				
Contingencies	\$	1,591,067	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$	1,591,067		
Total Installed Cost (TIC)	\$	5,242,695		
NO _x Emissions Before Control, lb/MMBtu	 	0.098		
NO _x Emissions Before Control, tn/yr		16.18		
NO _x Emissions After Control, lb/MMBtu		0.025		
Control Efficiency (%)		75		
NO _x Emissions After Control, tn/yr		4.05		
NO _x Emission Reduction, tn/yr		12.14		
Annual Costs, \$/year (Direct + Indirect)				
Direct Costs				
Operating Labor	\$	157,281	3% of capitol of	l rost
Raw materials	ς	-	370 Of Capitor	
Replacement Parts	\$	157,281	3% of capitol of	cost
Total Direct Costs, \$/year	\$	314,562	o, o o o oup ito	
Indianat Costs	1			
Indirect Costs Overhead	۲.	04.200	600/ of labar -	l
	\$		60% of labor of	
Taxes, Insurance, and Administration	\$		4% of total ins	
Capitol Recovery	\$ \$	689,257	10%, 15 years	, CNF1314/
Total Indirect Costs, \$/year	\$	993,333		
Total Annual Cost	_	1,307,895		
Cost Effectiveness, \$ per ton NO _x reduction	\$	107,763.10		

Assumptions:

$\mathrm{NO_x}$ Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 7H1

	L	MD/SCR	Factor	Basis for Cost
		Upgrade		and Factor
Direct Costs:				
Puchased Equipment:				
Primary and Auxiliary Equipment (PE)	\$	649,038	Include cos	its to convert to MD and add SCR
Sales Tax	\$	38,942	6% of PE	OTC-LADCO 2008
Freight	\$	32,452	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$	720,432		
Direct Installation				
Electrical, Piping, Insulation and Ductwork	\$	288,173	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$	288,173		
Total Direct Cost (DC)	\$	1,008,605		
Indirect Installation Costs				
Engineering and Project Management,				
Construction and Field Expenses, Contractor				
Fees, Startup Expenses, Performance Tests,				
Contingencies	\$	439,464	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$	439,464		
Total Installed Cost (TIC)	\$	1,448,069		
NO _x Emissions Before Control, lb/MMBtu	Ť	0.098		
NO _x Emissions Before Control, tn/yr		1.89		
NO _x Emissions After Control, lb/MMBtu		0.025		
Control Efficiency (%)		75		
NO _x Emissions After Control, tn/yr		0.47		
NO _x Emission Reduction, tn/yr		1.42		
Annual Costs, \$/year (Direct + Indirect) Direct Costs				
Operating Labor	\$	12 112	3% of capitol of	l cost
Raw materials	ς ς	43,442	3% of capitor (
Replacement Parts	\$	43,442	3% of capitol (Cost
Total Direct Costs, \$/year	\$	86,884	370 Of Capitor	
Total Direct Costs, 57 year	7	00,004		
Indirect Costs				
Overhead	\$		60% of labor of	
Taxes, Insurance, and Administration	\$		4% of total ins	
Capitol Recovery	\$	190,378	10%, 15 years	, CRF13147
Total Indirect Costs, \$/year	\$	274,366		
Total Annual Cost	\$	361,250		
Cost Effectiveness, \$ per ton NO _x reduction	\$	255,031.23		

Assumptions:

$\mathrm{NO_x}$ Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 7H3

		MD/SCR	Factor	Basis for Cost
		Upgrade		and Factor
Direct Costs:				
Puchased Equipment:				
Primary and Auxiliary Equipment (PE)	\$	2,189,269	Include cost	s to convert to MD and add SCR
Sales Tax	\$	131,356	6% of PE	OTC-LADCO 2008
Freight	\$	109,463	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$	2,430,089		
Direct Installation				
Electrical, Piping, Insulation and Ductwork	\$	972,035	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$	972,035		
Total Direct Cost (DC)	\$	3,402,124		
Indirect Installation Costs				
Engineering and Project Management,	+			
Construction and Field Expenses, Contractor				
Fees, Startup Expenses, Performance Tests,				
Contingencies	\$	1,482,354	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$	1,482,354		
Total Installed Cost (TIC)	\$	4,884,478		
NO _x Emissions Before Control, lb/MMBtu	+	0.098		
NO _x Emissions Before Control, tn/yr		14.29		
NO _x Emissions After Control, lb/MMBtu		0.025		
Control Efficiency (%)		75		
NO _x Emissions After Control, tn/yr		3.57		
NO _x Emission Reduction, tn/yr		10.72		
Annual Costs, \$/year (Direct + Indirect)				
Direct Costs				
Operating Labor	\$	146.534	3% of capitol of	cost
Raw materials	\$	-		
Replacement Parts	\$	146,534	3% of capitol of	cost
Total Direct Costs, \$/year	\$	293,069	·	
Indirect Costs				
Overhead	\$	87.921	60% of labor of	costs
Taxes, Insurance, and Administration	\$		4% of total ins	
Capitol Recovery	\$		10%, 15 years	
Total Indirect Costs, \$/year	\$	925,462	, = ,====	
Total Annual Cost	\$	1,218,531		
Cost Effectiveness, \$ per ton NO _x reduction	_	113,666.06		

Assumptions:

$\mathrm{NO_x}$ Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 9H1

	MD/SCR		Factor	Basis for Cost
		Upgrade		and Factor
Direct Costs:				
Puchased Equipment:				
Primary and Auxiliary Equipment (PE)	\$	936,333	Include cost	ts to convert to MD and add SCR
Sales Tax	\$	56,180	6% of PE	OTC-LADCO 2008
Freight	\$	46,817	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$	1,039,330		
Direct Installation				
Electrical, Piping, Insulation and Ductwork	\$	415,732	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$	415,732		
Total Direct Cost (DC)	\$	1,455,061		
Indirect Installation Costs				
Engineering and Project Management,				
Construction and Field Expenses, Contractor				
Fees, Startup Expenses, Performance Tests,				
Contingencies	\$	633,991	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$	633,991		
Total Installed Cost (TIC)	\$	2,089,053		
NO _x Emissions Before Control, lb/MMBtu	Ť	0.098		
NO _x Emissions Before Control, tn/yr		3.48		
NO _x Emissions After Control, lb/MMBtu		0.025		
Control Efficiency (%)		75		
NO _x Emissions After Control, tn/yr		0.87		
NO _x Emission Reduction, tn/yr		2.61		
Annual Costs, \$/year (Direct + Indirect)	-			
Direct Costs				
Operating Labor	\$	62 672	3% of capitol of	cost
Raw materials	\$	-	2.00. Supitor (
Replacement Parts	\$	62,672	3% of capitol of	cost
Total Direct Costs, \$/year	\$	125,343	'	
Indirect Costs	+			
Overhead	\$	37,603	60% of labor of	osts
Taxes, Insurance, and Administration	\$	•	4% of total ins	
Capitol Recovery	\$	274,648	10%, 15 years,	
Total Indirect Costs, \$/year	\$	395,813	,,, = ,==	-
Total Annual Cost	\$	521,156		
Cost Effectiveness, \$ per ton NO _x reduction	\$	199,857.86		

Assumptions:

$\mathrm{NO_x}$ Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 9H2

		MD/SCR	Factor	Basis for Cost	
		Upgrade		and Factor	
Direct Costs:					
Puchased Equipment:					
Primary and Auxiliary Equipment (PE)	\$	622,092	Include cos	ts to convert to MD and add SCR	
Sales Tax	\$	37,326	6% of PE	OTC-LADCO 2008	
Freight	\$	31,105	5% of PE	OTC-LADCO 2008	
Total Purchased Equipment Cost (PEC)	\$	690,522			
Direct Installation					
Electrical, Piping, Insulation and Ductwork	\$	276,209	40% of PEC	OTC-LADCO 2008	
Total Direct Installation (DI)	\$	276,209			
Total Direct Cost (DC)	\$	966,731			
Indirect Installation Costs					
Engineering and Project Management,					
Construction and Field Expenses, Contractor					
Fees, Startup Expenses, Performance Tests,					
Contingencies	\$	421,218	61% of PEC	OTC-LADCO 2008	
Total Indirect Cost	\$	421,218	01/00::10	0.0 1.0 00 1000	
	, ·	,			
Total Installed Cost (TIC)	\$	1,387,949			
NO _x Emissions Before Control, lb/MMBtu		0.098			
NO _x Emissions Before Control, tn/yr		1.76			
NO _x Emissions After Control, lb/MMBtu		0.025			
Control Efficiency (%)		75			
NO _x Emissions After Control, tn/yr		0.44			
NO _x Emission Reduction, tn/yr		1.32			
Annual Costs, \$/year (Direct + Indirect)					
Direct Costs					
Operating Labor	\$	41.638	3% of capitol of	cost	
Raw materials	\$	-	z, c c. supitor		
Replacement Parts	\$	41,638	3% of capitol of	cost	
Total Direct Costs, \$/year	\$	83,277			
Indirect Costs					
Overhead	\$		60% of labor costs		
Taxes, Insurance, and Administration	\$		4% of total ins		
Capitol Recovery	\$	•	10%, 15 years,	, CRF13147	
Total Indirect Costs, \$/year	\$	262,975			
Total Annual Cost	\$	346,252			
Cost Effectiveness, \$ per ton NO _x reduction	\$	262,329.22			

Assumptions:

$\mathrm{NO_x}$ Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 10H1

	MD/SCR		Factor	Basis for Cost
		Upgrade		and Factor
Direct Costs:				
Puchased Equipment:				
Primary and Auxiliary Equipment (PE)	\$	1,255,520	Include co	sts to convert to MD and add SCR
Sales Tax	\$	75,331	6% of PE	OTC-LADCO 2008
Freight	\$	62,776	5% of PE	OTC-LADCO 2008
Total Purchased Equipment Cost (PEC)	\$	1,393,627		
2: !! .:	-			
Direct Installation	<u> </u>	FF7 4F4	400/ -f DEC	OTC A DCO 2000
Electrical, Piping, Insulation and Ductwork	\$	557,451	40% of PEC	OTC-LADCO 2008
Total Direct Installation (DI)	\$	557,451		
Total Direct Cost (DC)	\$	1,951,078		
Indirect Installation Costs				
Engineering and Project Management,				
Construction and Field Expenses, Contractor				
Fees, Startup Expenses, Performance Tests,				
Contingencies	\$	850,113	61% of PEC	OTC-LADCO 2008
Total Indirect Cost	\$	850,113		
Total Installed Cost (TIC)	\$	2,801,191		
NO _x Emissions Before Control, lb/MMBtu		0.098		
NO _x Emissions Before Control, tn/yr		5.67		
NO _x Emissions After Control, lb/MMBtu		0.025		
Control Efficiency (%)		75		
NO _x Emissions After Control, tn/yr		1.42		
NO _x Emission Reduction, tn/yr		4.25		
Annual Costs, \$/year (Direct + Indirect)				
Direct Costs				
Operating Labor	\$	84,036	3% of capitol of	cost
Raw materials	\$	-		
Replacement Parts	\$		3% of capitol of	cost
Total Direct Costs, \$/year	\$	168,071		
Indirect Costs	+			
Overhead	\$	50 <i>4</i> 21	60% of labor of	l rosts
Taxes, Insurance, and Administration	\$	-	4% of total ins	
Capitol Recovery	\$	-	10%, 15 years	
Total Indirect Costs, \$/year	\$	530,742	2070, 20 years	,
Total Annual Cost	\$	698,813		
Cost Effectiveness, \$ per ton NO _x reduction	-1	164,446.87		
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Assumptions:

$\mathrm{NO_x}$ Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 11H1

	MD/SCR		Factor	Basis for Cost	
		Upgrade		and Factor	
Direct Costs:					
Puchased Equipment:					
Primary and Auxiliary Equipment (PE)	\$	1,807,112	Include cos	its to convert to MD and add SCR	
Sales Tax	\$	108,427	6% of PE	OTC-LADCO 2008	
Freight	\$	90,356	5% of PE	OTC-LADCO 2008	
Total Purchased Equipment Cost (PEC)	\$	2,005,894			
Direct Installation					
Electrical, Piping, Insulation and Ductwork	\$	802,358	40% of PEC	OTC-LADCO 2008	
Total Direct Installation (DI)	\$	802,358			
Total Direct Cost (DC)	\$	2,808,252			
Indirect Installation Costs					
Engineering and Project Management,					
Construction and Field Expenses, Contractor					
Fees, Startup Expenses, Performance Tests,					
Contingencies	\$	1,223,596	61% of PEC	OTC-LADCO 2008	
Total Indirect Cost	\$	1,223,596			
Total Installed Cost (TIC)	\$	4,031,848			
NO _x Emissions Before Control, lb/MMBtu		0.098			
NO _x Emissions Before Control, tn/yr		10.39			
NO _x Emissions After Control, lb/MMBtu		0.025			
Control Efficiency (%)		75			
NO _x Emissions After Control, tn/yr		2.60			
NO _x Emission Reduction, tn/yr		7.79			
Annual Costs, \$/year (Direct + Indirect)					
Direct Costs	1				
Operating Labor	\$	120.955	3% of capitol of	cost	
Raw materials	\$	-	2,00.0000000000000000000000000000000000		
Replacement Parts	\$	120,955	3% of capitol of	cost	
Total Direct Costs, \$/year	\$	241,911			
Indirect Costs					
Overhead	\$	72,573	60% of labor c	osts	
Taxes, Insurance, and Administration	\$		4% of total ins		
Capitol Recovery	\$		10%, 15 years,		
Total Indirect Costs, \$/year	\$	763,914	,, = ,=====	-	
Total Annual Cost	\$	1,005,825			
Cost Effectiveness, \$ per ton NO _x reduction	\$	129,105.76			

Assumptions:

$\mathrm{NO_x}$ Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 13H1

	MD/SCR		Factor	Basis for Cost	
	Upgrade			and Factor	
Direct Costs:					
Puchased Equipment:					
Primary and Auxiliary Equipment (PE)	\$	820,413	Include co	sts to convert to MD and add SCR	
Sales Tax	\$	49,225	6% of PE	OTC-LADCO 2008	
Freight	\$	41,021	5% of PE	OTC-LADCO 2008	
Total Purchased Equipment Cost (PEC)	\$	910,658			
Direct Installation					
Electrical, Piping, Insulation and Ductwork	\$	364,263	40% of PEC	OTC-LADCO 2008	
Total Direct Installation (DI)	\$	364,263			
Total Direct Cost (DC)	\$	1,274,922			
Indirect Installation Costs					
Engineering and Project Management,					
Construction and Field Expenses, Contractor					
Fees, Startup Expenses, Performance Tests,					
Contingencies	\$	555,502	61% of PEC	OTC-LADCO 2008	
Total Indirect Cost	\$	555,502			
Total Installed Cost (TIC)	\$	1,830,423			
NO _x Emissions Before Control, lb/MMBtu		0.098			
NO _x Emissions Before Control, tn/yr		2.79			
NO _x Emissions After Control, lb/MMBtu		0.025			
Control Efficiency (%)		75			
NO _x Emissions After Control, tn/yr		0.70			
NO _x Emission Reduction, tn/yr		2.09			
Annual Costs, \$/year (Direct + Indirect)	-				
Direct Costs					
Operating Labor	\$	54 913	3% of capitol (L Cost	
Raw materials	\$		2.00.0000000	T	
Replacement Parts	\$	54.913	3% of capitol (cost	
Total Direct Costs, \$/year	\$	109,825			
Indirect Costs	+				
Overhead	\$	32.948	60% of labor of	costs	
Taxes, Insurance, and Administration			4% of total installed cost		
Capitol Recovery	\$		5 10%, 15 years, CRF13147		
Total Indirect Costs, \$/year	\$	346,810	3.2, 20 10010	,	
Total Annual Cost	\$	456,636			
Cost Effectiveness, \$ per ton NO _x reduction		218,220.27			
					

Assumptions:

ATTACHMENT 3

Monitoring Recommendations and Emission Limitations

March Col.	Emissions Unit	Parameter	Immary of Allowable Limits and Monitoring Require	Monitoring	Comment
State Vic. Story pure conscious average at 198 (s) sin and Story pure conscious average at 198 (s) sin and Story pure conscious average at 198 (s) sin and Story sin and s	Lillissions offit	Parameter	Allowable Limit		Comment
CO SOO promise analyses are say at 8 Pg. 1 has not good to the promise of the Company of the	Unit 4 - FCCU	VOC	Allowable Little	прргоден	Must comply with LDAR program
March Marc			≤500 ppmv one-hour average at 0% 0 ₂ 1-hr avg.	CEMS	
2015 2015					
See protection of See See See See See See See See See Se		- 4			
Section of 2006 per 7-day colling overage CRSS Section CRSS Section CRSS		SO_2			
PM		-	≤50 ppmdv at 0% O ₂ per 7-day rolling average		
March Complete CDS CDS CDS CDS				Stack Test,	
## Section of the content of the con		PM_{10}	0.50 lb/1000 lb coke burned	COMS/AMP	Stack test no later than October 31 of each year
Special Content Special Co	4H1 - FCC Feed Heater	Opacity			
Social Contemporaries Soci					CEMS located at plant fuel gas mix drum/header
Solid Soli	4V82 FCC Scrubber			COMS	
Unit 1 - Catalytic Reforming bit with Charge feature Charge featur					
High High Heather Charge Heater Part Pa	Unit 6 Catalytic Deforming	SO_2	17.7 tons per year		
Self-Reformer Channer Betweet Plans Plans		1100			W . I SIVEAD
PM			100/		Must comply with LDAK program
Heaver He	on 1-Reformer Charge heater		10%		DM emissions based on 7.65 lb DM /MMscf
April Proceedings Process Pr			<60 npm (annual average)	CEMS	
Digital Digi	6H2 - Prefractionator Reboiler	1125	200 ppin (annua average)	GEMS	one of the state o
PM_s	Heater	Opacity	10%		
Hart 7 - Alkylation Unit PM 2 Hart 7 - Alkylation Unit PM 2 Hart 7 - Alkylation Unit PM 2 Hart 7 - Alkylation Unit PM 3 Hart 11 - Malystone Regeneration PM 3 Hart 11 - Malystone Regeneration PM 3 Hart 12 - Malystone Regeneration PM 3 Hart 13 - Malystone Regeneration PM 3 Hart 14 - Alkylation Unit PM 3 Hart 15 - Alkylation Digregamizer Rebouler PM 3 Hart 15 - Alkylation Digregamizer Rebouler PM 4 Hart 15 - Chude Unit PM 4 Hart 17 - Alkylation Digregamizer Rebouler PM 4 Hart 18 - Chude Unit PM 4 Hart 19 - Distillate PM 4 Hart 19 - Distillate PM 4 Hart 19 - Distillate PM 5 Hart 19 - Distillate PM 6					PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf
PM, genesions based on 7.65 ib PM, //Moded			≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
PM, genesions based on 7.65 ib PM, //Moded					
Hair 7 - Alkylation Unit 171 - 181 Alkylation Unit 171 - 181 Alkylation Engeneration 172 - 181 Alkylation Deproparater Netwolser 173 - 185	6H3 - Reformer Reheater Furnace		10%		
Unit 7 - Alkylation Unit PH. 11-18 Alkylation Regeneration Purnace PH. 12-18 Alkylation Regeneration PH. 13-18 Alkylation Regeneration PH. 14-18 Alkylation Regeneration PH. 15-18 Alkylation Ph. 15-18 Alkylation PH. 15-18 Alkylation Regeneration PH. 15-18 Alkylation PH. 18-18 Alky				am. / -	
PH. 14 Hz Alsylation Regeneration Phd.,	Harite II Allandari II i		≤60 ppm (annual average)	CEMS	
Figure 19		VOC			Must comply with LDAK program
PH.1 + FAllylation Depropanier PH.5		Opacity	1004		
H3. HF Alkylation Depropanier Reboiler	ruindle		10 /0		PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf
PM: 1 HR Alphaten Depropanier Reboiler Unit 8 - Crude Unit 1872 - Crude Pursace 1873 - Wo C 1874 - Wo C 1874 - Wo C 1875 - Wo C			<60 npm (annual average)	CEMS	
Phosphate Phos	7H3 - HF Alkylation Depropanizer	1125	200 ppin (annua average)	CEMS	only rocated at plant faci gas mix aram/ neader
Unit 8 - Crude Unit 1812 - Crude Furnace 1812 - Crude Furnace 1812 - Crude Furnace 1813 - Crude Furnace 1814 - Crude Furnace 1815 - Crude Furnace 1815 - Crude Furnace 1816 - Crude Furnace 1817 - Opacity 1815 - Month Milks 3-hour average 1816 - Month Milks 3-hour average 1811 - Milks 3-hour average 1811 - Milks 3-hour average 1812 - Opacity 1813 - Sopper (annual average) 1814 - Milks 3-hour average 1815 - Opacity 1816 - Opacity 1816 - Opacity 1817 - Opacity 1818 - Opaci	Reboiler	Opacity	10%		
Unit 9 - Distillate PM_					PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf
Digit 1 - Solvent Digi			≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
PM NO NO HJMMBtu 3-hour average CEMS CE	Unit 8 - Crude Unit	VOC			Must comply with LDAR program
Unit 9 - Distillate Hydrosulfurization Unit Woc Distillate Hydrosulfurization Unit Woc Distillate Hydrosulfurization Unit Distillate Hydrosulfurization Unit Distillate Hydrosulfurization HyS Distillate Hydrosulfurization HyS Distillate HyB Disti	8H2 - Crude Furnace	Opacity	10%		
Unit 9 - Distrillate Hydrosculfurization Unit His-DibDS Reactor Charge Heater Diby PM ₁₉ His-Dibb Stripper Reboiler His-Dibb Stripper Reboiler Diby PM ₁₉ His-Dibb Stripper Reboiler Diby PM ₁₉ His-Dibb Stripper Reboiler His-Dibb Stripper Reboiler Dibit 1 - Solvent Deasphalting Unit Deasphalting Unit Dibit 1 - Solvent Deasphalting Unit Dibit 1 - Solvent Deasphalting Unit Dibit 1 - Solvent Deasphalting Unit Dibit 2 - Hot Oil Furnace Dibit 2 - Hot Oil Furnace Dibit 3 - Bord Dibit 4 - Bord Dibit 4 - Bord Dibit 5		PM_{10}	0.00051 lb/MMBtu		Stack test no later than October 31 of each year
Unit 1 - Solvent Deachy Phys Hg Possitifier Hg Pos		NO_x	0.04 lb/MMBtu 3-hour average		
Hydrosulfurization Unit Hi-DHDS Reactor Charge Heater Opacity PM ₁₀ Hi-DHDS Stripper Reboiler Opacity PM ₁₀ Hi-DHDS Stripper Reboiler PM ₁₀ Hi-DHDS Stripper Reboiler PM ₁₀ Hi-DHDS Repair No. Opacity PM ₁₀ Hi-DHDS Responder PM ₁₀ NO. Opacity PM ₁₀ Hi-DHDS Responder PM ₁₀ Hi-DHDS Responder PM ₁₀ NO. Opacity PM ₁₀ NO. Opacity PM ₁₀ NO. Opacity PM ₁₀ NO. Opacity PM ₁₀ Hi-DHDS Responder PM ₁₀ NO. Opacity PM ₁₀		H ₂ S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Hi-DHDS Reactor Charge Heater Hi-S His Dipolity Philip His Stripper Reboiler Hi-S His Dipolity Philip His Sopper (CEMS of the His Dipolity Philip His Dipolity Philip His Sopper (CEMS of the His Dipolity Philip His Dipolity					
PM ₁₀ FS So part PM ₁₀ FS So part PM ₁₀	Hydrosulfurization Unit	VOC			Must comply with LDAR program
PM ₁₀ FS So part PM ₁₀ FS So part PM ₁₀					
H2-DHDS Stripper Reboiler Opacity PM ₁₀ Unit 10 - Solvent Deasphalting Unit Unit 1 - Solvent Deasphalting Unit Unit 1 - Solvent Opacity PM ₁₀ NO ₈ NO ₈ NO ₈ Opacity PM ₁₀ NO ₈ NO	9H1-DHDS Reactor Charge Heater		10%		DM amissions based on 7.65 lb DM /MMosf
### Deaphalting Unit Unit 10 - Solvent Deaphalting Unit Opacity PM ₁₀ H,S Sol ppm (annual average) VC Opacity PM ₁₀ H,S Sol ppm (annual average) CEMS CEMS located at plant fuel gas mix drum/header Must comply with LDAR program Unit 11 - Straight Run Gas Plant NO Opacity PM ₁₀ H,S Sol ppm (annual average) Unit 11 - Straight Run Gas Plant VC Opacity PM ₁₀ H,S Sol ppm (annual average) Uoc Opacity PM ₁₀ H,S Sol ppm (annual average) CEMS CEMS located at plant fuel gas mix drum/header CEMS Stack test no later than October 31 of each year Stack test performed every 3 years CEMS CEMS located at plant fuel gas mix drum/header Unit 11 - Straight Run Gas Plant VC Opacity PM ₁₀ H,S Sol ppm (annual average) Unit 12 - Naphtha Hydrodesulphurization Unit VC Unit 13 - Isomerization Unit 1311: Isomerization Reactor Feed Furnace Opacity PM ₁₀ Opacity PM ₁₀ Opacity PM ₁₀ Sol ppm (annual average) Unit 13 - Isomerization Reactor Feed Furnace Opacity PM ₁₀ Opacity PM ₁₀ Sol ppm (annual average) Unit 14 - Amine Treatment Unit VOC Sulfur Sol ppm (annual average) Unit 15 - Sulfur Recovery Unit VOC Sulfur Sol ppm (annual average) Unit 16 - Amine Treatment Unit VOC Sulfur Sol ppm (annual average) Unit 16 - Amine Treatment Unit VOC Sulfur Sol ppm (annual average) Unit 16 - Amine Treatment Unit VOC Sulfur Sol ppm (annual average) Unit 16 - Amine Treatment Unit VOC Sulfur Sol ppm (annual average) Unit 16 - Amine Treatment Unit VOC Sulfur Sol ppm (annual average) Unit 16 - Amine Treatment Unit VOC Sulfur Sol ppm (annual average) Unit 17 - Sulfur Recovery Unit VOC Sulfur Sol ppm (annual average) Unit 18 - Sulfur Recovery Unit VOC Sulfur Sol ppm (annual average) CEMS CEMS CEMS CEMS CEMS CEMS CEMS CEMS CEMS			c60 npm (annual avorage)	CEMS	
Unit 10 - Solvent Deasphalting Unit Unit 10 - Solvent Deasphalting Unit Unit 11 - Solvent Deasphalt Mix Heater Unit 12 - Hot Oil Furnace PM ₁₀	QH2-DHDS Stripper Rehailer		** *	CEMS	CEMS located at plant fuel gas mix drum/neader
Unit 10 - Solvent Deasphalting Unit Unit 10 - Solvent Deasphalting Unit Unit 1 - Asphalt Mix Heater PMin PMin PMin No No No No No No No H;S Solopm (annual average) Unit 11 - Straight Run Gas Plant PMin His Solopm (annual average) Unit 11 - Straight Run Gas Plant Unit 12 - Naphtha Hydrodesulphurization Unit Unit 13 - Somerization Unit 13H1 - Isomerization Reactor Feed Furnace Unit 16 - Amine Treatment Unit Unit 17 - Sulfur Recovery Unit VOC Sulfur Solop pm (annual average) Solop pm (annual average) Solop pm (annual average) CEMS CEMS located at plant fuel gas mix drum/header Stack test performed every 3 years CEMS located at plant fuel gas mix drum/header CEMS Stack test performed every 3 years CEMS located at plant fuel gas mix drum/header Must comply with LDAR program CEMS CEMS located at plant fuel gas mix drum/header CEMS CEMS located at plant fuel gas mix drum/header Must comply with LDAR program Must comply with LDAR program Must comply with LDAR program CEMS located at plant fuel gas mix drum/header CEMS located at plant fuel gas mix drum/header CEMS located at plant fuel gas mix drum/header Must comply with LDAR program Must comply with LDAR program COMPlant located at plant fue	7112-D11D3 3tt ipper Reboller		10 /0		PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf
Unit 10 - Solvent Deasphalting Unit U0H1 - Asphalt Mix Heater Opacity PMio H;S Opacity PMio No No No No H;S Solop m (annual average) Ocems No H;S Solop m (annual average) No			≤60 ppm (annual average)	CEMS	
Deasphalting Unit 10H1 - Asphalt Mix Heater 10H2 - Hot Oil Furnace 10H2 - Hot Oil Furnace 10H3 - Mount of PM ₁₀ 10H5 - Mount of PM ₁₀ 10H6 - Mount of PM ₁₀ 1	Unit 10 - Solvent	2-	C C C C C C C C C C C C C C C C C C C		, , , , , , , , , , , , , , , , , , , ,
10H2 - Hot Oil Furnace Opacity PM ₁₀ H ₂ S S60 ppm (annual average) CEMS CEMS located at plant fuel gas mix drum/header Stack test no later than October 31 of each year Stack test performed every 3 years CEMS located at plant fuel gas mix drum/header CEMS located at plant fuel gas mix drum/header CEMS located at plant fuel gas mix drum/header CEMS located at plant fuel gas mix drum/header Must comply with LDAR program Must comply with LDAR program CEMS located at plant fuel gas mix drum/header Must comply with LDAR program Must comply with LDAR program Must comply with LDAR program CEMS located at plant fuel gas mix drum/header Must comply with LDAR program Must comply with LDAR program CEMS located at plant fuel gas mix drum/header Must comply with LDAR program CEMS located at plant fuel gas mix drum/header Must comply with LDAR program CEMS located at plant fuel gas mix drum/header Must comply with LDAR program CEMS located at plant fuel gas mix drum/header CEMS located at plant fuel gas mix drum/header CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf CEMS located at plant fuel gas mix drum/header Must comply with LDAR program Must comply with LDAR program Must comply with LDAR program CEMS located at plant fuel gas mix drum/header CEMS located at plant fuel gas mix drum/header CEMS located at plant fuel gas mix drum/header Must comply with LDAR program Must comply with LDAR program Must comply with LDAR p	Deasphalting Unit	VOC			Must comply with LDAR program
PM ₁₀ H ₂ S \$60 ppm (annual average) CEMS CEMS located at plant fuel gas mix drum/header Stack test no later than October 31 of each year Stack test performed every 3 years CEMS located at plant fuel gas mix drum/header CEMS located at plant fuel gas mix drum/hea	10H1 - Asphalt Mix Heater		10%		
10H2 - Hot Oil Furnace					
PM ₁₀ NO ₂ 0.00051 lb/MMBtu CEMS Stack test no later than October 31 of each year Stack test performed every 3 years CEMS Stack test performed every 3 years CEMS Stack test performed every 3 years CEMS		H ₂ S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 11 - Straight Run Gas Plant PM10 H2S S60 ppm (annual average) SCEMS CEMS In Stack test performed every 3 years CEMS In Interpretation PM10 Must comply with LDAR program Must comply with LDAR program Must comply with LDAR program CEMS In PM10 PM10 PM10 PM10 PM10 PM10 Must comply with LDAR program CEMS Interpretation based on 7.65 lb PM10/MMscf CEMS Interpretation PM10 Must comply with LDAR program CEMS Interpretation PM10 Must comply with LDAR program CEMS Interpretation PM10 PM10 NO, H2S Stack test performed every 3 years Stack test performed every 3 years Stack test performed every 3 years CEMS Interpretation PM10 CEMS Interpretation PM10 CEMS Interpretation PM10 CEMS Interpretation PM10 PM10 PM10 PM10 PM10 PM10 PM10 PM10	10H2 - Hot Oil Furnace	Opacity			
Unit 11 - Straight Run Gas Plant PM10 H2S S60 ppm (annual average) SCEMS CEMS In Stack test performed every 3 years CEMS In Interpretation PM10 Must comply with LDAR program Must comply with LDAR program Must comply with LDAR program CEMS In PM10 PM10 PM10 PM10 PM10 PM10 Must comply with LDAR program CEMS Interpretation based on 7.65 lb PM10/MMscf CEMS Interpretation PM10 Must comply with LDAR program CEMS Interpretation PM10 Must comply with LDAR program CEMS Interpretation PM10 PM10 NO, H2S Stack test performed every 3 years Stack test performed every 3 years Stack test performed every 3 years CEMS Interpretation PM10 CEMS Interpretation PM10 CEMS Interpretation PM10 CEMS Interpretation PM10 PM10 PM10 PM10 PM10 PM10 PM10 PM10		PM_{10}			
Unit 11 - Straight Run Gas Plant VOC VOC VOC VOC VOC VOC VOC VO		NO_x	· -		* * *
Plant Unit 13- Isomerization Unit 13H1 - Smore Feed Furnace Feed Furnace Unit 16 - Amine Treatment Unit Unit Unit Unit Unit Unit Suffer Feed Furnace Unit 17 - Sulfur Recovery Unit Unit Unit Unit Unit Unit Unit Unit		H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
11H1 - SRGP Depentanizer Reboiler Opacity PM ₁₀ H ₂ S 660 ppm (annual average) CEMS CEMS located at plant fuel gas mix drum/header Must comply with LDAR program PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf CEMS located at plant fuel gas mix drum/header Must comply with LDAR program PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf Stack test performed every 3 years CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf Stack test performed every 3 years CEMS located at plant fuel gas mix drum/header VOC Unit 13 - I somerization Unit 13H1 - I somerization Reactor Feed Furnace Opacity PM ₁₀ H ₂ S 60 ppm (annual average) CEMS CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /Mmscf CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /Mmscf CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /Mmscf CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /Mmscf CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /Mmscf CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /Mmscf CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /Mmscf CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /Mmscf CEMS located at plant fuel gas mix drum/header CEMS located at plant fuel gas mix drum/header	Unit 11 - Straight Run Gas				
Reboiler Opacity PM ₁₀ H ₂ S s60 ppm (annual average) CEMS CEMS CEMS located at plant fuel gas mix drum/header Must comply with LDAR program Opacity PM ₁₀ NO _x Opacity PM ₁₀ NO _x Opacity PM ₁₀ NO _x H ₂ S s60 ppm (annual average) CEMS CEMS located at plant fuel gas mix drum/header Must comply with LDAR program CEMS CEMS located at plant fuel gas mix drum/header Must comply with LDAR program CEMS located at plant fuel gas mix drum/header Must comply with LDAR program CEMS located at plant fuel gas mix drum/header CEMS located at plant fuel gas mix drum/header Must comply with LDAR program CEMS located at plant fuel gas mix drum/header	Plant	VOC			Must comply with LDAR program
Unit 12- Naphtha Hydrodesulphurization Unit Unit 12- Naphtha Hydrodesulphurization Unit Unit 12- NHDS Reactor Charge Furnace Opacity PM10 NO NO H2S S60 ppm (annual average) Opacity PM10 NO NO NO H2S S60 ppm (annual average) Opacity PM10 NO NO NO H2S S60 ppm (annual average) Opacity PM10 NO NO H2S S60 ppm (annual average) CEMS CEMS Opacity PM10 NO NO CEMS CEMS CEMS located at plant fuel gas mix drum/header PM10 emissions based on 7.65 lb PM10/MMscf Stack test performed every 3 years CEMS located at plant fuel gas mix drum/header CEMS CEMS located at plant fuel gas mix drum/header Opacity PM10 H2S S60 ppm (annual average) CEMS CEMS located at plant fuel gas mix drum/header CEMS located at plant fuel gas mix drum/header Opacity PM10 H2S S60 ppm (annual average) CEMS CEMS located at plant fuel gas mix drum/header Must comply with LDAR program Must comply with LDAR program Gompliance based on flow rate and H2S concentration in the feed and		Ome = ! !	100/		
Unit 12- Naphtha Hydrodesulphurization Unit 12H1 - NHDS Reactor Charge Furnace Opacity PM ₁₀ NO _x Opacity H ₂ S Opacity PM₁₀ NO_x H₂S Opacity PM₁₀ H₂S Opacity	Redoller		10%		DM emissions based on 7.45 lb DM /MMass
Unit 12- Naphtha Hydrodesulphurization Unit Unit U2H - NHDS Reactor Charge Furnace Opacity PM ₁₀ NO _x 0.10 lb/MMBtu 3-hour average H ₂ S 560 ppm (annual average) CEMS Opacity PM ₁₀ H ₂ S Sack test performed every 3 years CEMS located at plant fuel gas mix drum/header Unit 13- Isomerization Unit 13H1 - Isomerization Reactor Feed Furnace Opacity PM ₁₀ H ₂ S S60 ppm (annual average) CEMS CEMS CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf CEMS located at plant fuel gas mix drum/header Unit 16- Amine Treatment Unit Unit 17- Sulfur Recovery Unit VOC Sulfur S20 long tons per day Compliance based on flow rate and H ₂ S concentration in the feed and			c60 nnm (annual average)	CEMC	
Hydrodesulphurization Unit VOC VOC Opacity PM ₁₀ NO _x O,10 lb/MMBtu 3-hour average \$\frac{60}{19} \text{ pm} \text{ (annual average)} \text{ CEMS} \text{ CEMS located at plant fuel gas mix drum/header} \text{ Unit 13 - Isomerization Unit 13 - Isomerization Reactor Feed Furnace Opacity PM ₁₀ NO _x O,10 lb/MMBtu 3-hour average \$\frac{60}{19} \text{ pm} \text{ (annual average)} \text{ CEMS} \text{ CEMS located at plant fuel gas mix drum/header} \text{ CEMS located at plant fuel gas mix drum/header} \text{ Unit 14 - Amine Treatment Unit 17 - Sulfur Recovery Unit VOC Sulfur \$\frac{20}{100} \text{ long tons per day} \text{ CEMS compliance based on 7.65 lb PM\$_{10} / MMscf} \text{ CEMS located at plant fuel gas mix drum/header} \text{ Must comply with LDAR program} \text{ CEMS located at plant fuel gas mix drum/header} \text{ Must comply with LDAR program} \text{ CEMS located at plant fuel gas mix drum/header} \text{ CEMS located at plant fuel gas mix drum/header} \text{ CEMS located at plant fuel gas mix drum/header} \text{ CEMS located at plant fuel gas mix drum/header} \text{ CEMS located at plant fuel gas mix drum/header} \text{ Must comply with LDAR program} \text{ Compliance based on flow rate and H\$_2S concentration in the feed and } \text{ Compliance based on flow rate and H\$_2S concentration in the feed and } \text{ Compliance based on flow rate and H\$_2S concentration in the feed and } \text{ Compliance based on flow rate and H\$_2S concentration in the feed and } \text{ Compliance based on flow rate and H\$_2S concentration in the feed and } \text{ Compliance based on flow rate and H\$_2S concentration in the feed and } \text{ Compliance based on flow rate and H\$_2S concentration in the feed and } \text{ Compliance based on flow rate and H\$_2S concentration in the feed and } \text{ Compliance based on flow rate and H\$_2S concentration in the feed and } \text{ Compliance based on flow rate and H\$_2S concentration in the feed and } Compliance based on flow rate and H\$_2S concentration in the fee	Unit 12. Nanhtha	п25	200 ppin (annuai average)	CEM2	GENTS TO CALCULAT PLAINT LUCY GAS THIX UTUIN/ HEADER
Unit 13 - Isomerization Unit 13Hnore Feed Furnace Unit 14 - Amine Treatment Unit Unit 17 - Sulfur Recovery Unit Unit 17 - Sulfur Recovery Unit Unit 18 - Isomerization Charge Sulfur VOC Sulfur Sulfur Sulfur Substitute Unit 19 - Amine Treatment Unit VOC Sulfur Sulfur Sulfur Substitute Substitute Substitute Substitute Must comply with LDAR program Compliance based on flow rate and H ₂ S concentration in the feed and					
12H1 - NHDS Reactor Charge Furnace Opacity PM ₁₀ NO _x 0.10 lb/MMBtu 3-hour average Stack test performed every 3 years CEMS CEMS CEMS located at plant fuel gas mix drum/header Unit 13 - Isomerization Unit 13H1 - Isomerization Reactor Feed Furnace Opacity PM ₁₀ H ₂ S Se0 ppm (annual average) Unit 16 - Amine Treatment Unit Unit 17 - Sulfur Recovery Unit VOC Sulfur Sulfur Sulfur Sezo long tons per day Opacity PM ₁₀ H ₂ S Se0 ppm (annual average) CEMS CEMS CEMS located at plant fuel gas mix drum/header CEMS CEMS located at plant fuel gas mix drum/header Must comply with LDAR program Compliance based on flow rate and H ₂ S concentration in the feed and		VOC			Must comply with LDAP program
Furnace Opacity PM10 NOx 0.10 lb/MMBtu 3-hour average H2S <60 ppm (annual average) CEMS CEMS CEMS located at plant fuel gas mix drum/header Unit 13 - Isomerization Unit 13Hp 1- Isomerization Reactor Feed Furnace Opacity PM10 H2S Feed Furnace Opacity PM10 H2S Feed Furnace Opacity PM10 H2S Feed purpace Opacity PM10 Must comply with LDAR program Must comply with LDAR program Compliance based on flow rate and H2S concentration in the feed and		VUC			inust comply with EDAK program
$\begin{array}{c ccccccccccccccccccccccccccccccccccc$		Onacity	10%		
NO _x H ₂ S s60 ppm (annual average) CEMS Stack test performed every 3 years			/-		PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf
Unit 13 - Isomerization Unit 13H - Isomerization Reactor Feed Furnace Opacity PM ₁₀ H ₂ S 560 ppm (annual average) CEMS CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf CEMS located at plant fuel gas mix drum/header PM ₁₀ emissions based on 7.65 lb PM ₁₀ /MMscf CEMS located at plant fuel gas mix drum/header CEMS located at plant fuel gas mix drum/header VOC Sulfur VOC Sulfur Sulfur Selong tons per day Compliance based on flow rate and H ₂ S concentration in the feed and			0.10 lb/MMBtu 3-hour average		
Unit 13 - Isomerization Unit 13H1 - Isomerization Reactor Feed Furnace Opacity PM ₁₀ H ₂ S 60 ppm (annual average) Unit 16 - Amine Treatment Unit VOC Unit 17 - Sulfur Recovery Unit VOC Sulfur				CEMS	
13H1 - Isomerization Reactor Feed Furnace Opacity PM10 H2S 60 ppm (annual average) CEMS CEMS Isocated at plant fuel gas mix drum/header Unit 17 - Sulfur Recovery Unit VOC Sulfur Compliance based on 7.65 lb PM10/MMscf CEMS CEMS CEMS Isocated at plant fuel gas mix drum/header Must comply with LDAR program Compliance based on flow rate and H2S concentration in the feed and		2-			
13H1 - Isomerization Reactor Feed Furnace Opacity PM10 H2S 60 ppm (annual average) CEMS CEMS Isocated at plant fuel gas mix drum/header Unit 17 - Sulfur Recovery Unit VOC Sulfur Compliance based on 7.65 lb PM10/MMscf CEMS CEMS CEMS Isocated at plant fuel gas mix drum/header Must comply with LDAR program Compliance based on flow rate and H2S concentration in the feed and	Unit 13 - Isomerization Unit	VOC			
Feed Furnace Opacity PM10 PM10 H2S Se0 ppm (annual average) Opacity PM10 H2S Se0 ppm (annual average) CEMS CEMS CEMS located at plant fuel gas mix drum/header Must comply with LDAR program VOC Sulfur VOC Sulfur Sulfur Se0 long tons per day Compliance based on flow rate and H2S concentration in the feed and	13H1 - Isomerization Reactor				
Unit 16 - Amine Treatment Unit 17 - Sulfur Recovery Unit VOC Sulfur Sulfur VOC Sulfur Sulfur VOC Sulfur Sulf	Feed Furnace		10%		
Unit 16 - Amine Treatment Unit VOC Unit 17 - Sulfur Recovery Unit VOC Sulfur \$\frac{1}{20}\$ long tons per day Wast comply with LDAR program Must comply with LDAR program Compliance based on flow rate and H2S concentration in the feed and					
Unit VOC Unit 17 - Sulfur Recovery Unit VOC Sulfur		H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 17 - Sulfur Recovery Unit VOC Sulfur ≤20 long tons per day Compliance based on flow rate and H₂S concentration in the feed and	Unit 16 - Amine Treatment				
Unit VOC Sulfur Sul	Unit	VOC			Must comply with LDAR program
Sulfur ≤20 long tons per day Compliance based on flow rate and H₂S concentration in the feed and	Unit 17 - Sulfur Recovery				
Compliance based on flow rate and H ₂ S concentration in the feed and	Unit	VOC			Must comply with LDAR program
		Sulfur	≤20 long tons per day		
Sulfur 95% recovery on a 30-day average except during SSM SO ₂ CEMS			000		
		Sulfur	95% recovery on a 30-day average except during SSM		SO ₂ CEMS

Emissions Unit	Parameter	mmary of Allowable Limits and Monitoring Require	Monitoring	Comment
Zimosiono Cint	i di dilictei	Allowable Limit	Approach	Comment
	Sulfur	≤1.6 tn/day except during SSM	I I	
	SO ₂ , TRS, Temp	, , , , , , , , , , , , , , , , , , , ,	CEMS, CPMS	
Unit 18 - Sour Water	-,			
Stripping Unit	VOC			Must comply with LDAR program
Unit 19 - Distillate				
Hydrodesulferization				
Treatment	VOC			Must comply with LDAR program
19H1 - DHT Reactor Charge Heater	Opacity	10%		
lieatei	PM ₁₀	0.00051 lb/MMBtu		
	H ₂ S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 20 - Gas Oil	2-	3.77		, , , , , , , , , , , , , , , , , , , ,
Hydrocracking Unit	VOC			Must comply with LDAR program
20H1-Reactor Charge Heater	Opacity	10%		
	PM ₁₀	0.00051 lb/MMBtu		Stack test no later than October 31 of each year
	H ₂ S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
20H2-Fractionator Charge Heater	Opacity	10%		
20112-1 factionator charge freater	PM ₁₀	0.00051 lb/MMBtu		Stack test no later than October 31 of each year
	H ₂ S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
	-	(
20H3-Fractionator Charge Heater	Opacity	10%		
	PM ₁₀	0.00051 lb/MMBtu	OF MO	Stack test no later than October 31 of each year
	NO _x	0.04 lb/MMBtu 3-hour average	CEMS	Stack test performed every 3 years
Unit 21 - NaSH Sour Gas	H ₂ S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Treatment Unit	VOC			Must comply with LDAR program
Unit 22 - Sour Water	VOC			
Stripper/Ammonia				
Stripping Unit	VOC			Must comply with LDAR program
Unti 23 - Benzene				
Saturation Unit	VOC			Must comply with LDAR program
23H1-Reformate Splitter Reboiler				
Heater	Opacity	10%		
	PM ₁₀	0.00051 lb/MMBtu		Stack test no later than October 31 of each year
Unit 24- Crude Unit	H₂S VOC	≤60 ppm (annual average)		Most sound a stal I DAD and sound
24H1 - Crude Unit Furnace	Opacity	10%		Must comply with LDAR program
24111 - Grude Ollit Furliace	PM ₁₀	0.00051 lb/MMBtu		Stack test no later than October 31 of each year
	NO _x	0.04 lb/MMBtu 3-hour average	CEMS	Stack test performed every 3 years
	H ₂ S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 25 - FCCU	VOC			Must comply with LDAR program
	NO_x	≤40 ppmdv at 0% O₂ per 365-day rolling average	CEMS	
		≤80 ppmdv at 0% O ₂ per 7-day rolling average	CEMS	
	SO ₂	≤25 ppmdv at 0% O₂ per 365-day rolling average	CEMS	
		≤50 ppmdv at 0% O₂ per 7-day rolling average	CEMS	
25114 FCC F 1 11 1 1	PM ₁₀	0.50 lb/1000 lb coke burned	Stack Test	Stack test no later than October 31 of each year
25H1 - FCC Feed Heater	Opacity PM ₁₀	10% 0.00051 lb/MMBtu		
	NO _x	0.04 lb/MMBtu 3-hour average		Stack test performed every 3 years
	H ₂ S	≤60 ppm (annual average)		static test performed every 5 years
25FCC Scrubber	Opacity	15%		
	SO_2	0.05 tons per day		
	SO ₂	17.7 tons per year		
	PM ₁₀	0.30 lb/1000 lb coke burned		Stack test no later than October 31 of each year
	Flow		Flow meter	
Unit 26 - Poly Gasoline Unit	VOC			Must comply with LDAR program
Unit 27 -	100			
Hydrocracker/Hydroisom				
Unit	VOC			Must comply with LDAR program
27H1 - Reactor Charge Heater	Opacity	10%		
	PM_{10}	0.00051 lb/MMBtu		Stack test no later than October 31 of each year
	NO _x	0.02 lb/MMBtu 3-hour average		Stack test performed every 3 years
	NO _x	40 ppmv or 0.04 lb/MMBtu (30-day rolling average)	CEMS	NO _X CEMS or Excess O ₂ operating curve
Unit 28 - Sour Water	H ₂ S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Stripping Unit	VOC			Must comply with LDAR program
Unit 30 - Hydrogen Plant	VOC			Must comply with LDAR program Must comply with LDAR program
30H1 - Hydrogen Reformer Feed	VOC			
Furnace	Opacity	10%		
	PM_{10}	0.00051 lb/MMBtu		Stack test no later than October 31 of each year
	NO _x	0.02 lb/MMBtu 3-hour average		Stack test performed every 3 years
	NO _x	40 ppmv or 0.04 lb/MMBtu (30-day rolling average)	CEMS	
20H2 Hudroger Beformer F	H ₂ S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
30H2 - Hydrogen Reformer Feed Furnace	Opacity	10%		
	PM ₁₀	0.00051 lb/MMBtu		Stack test no later than October 31 of each year
	NO _x	0.02 lb/MMBtu 3-hour average		Stack test performed every 3 years
	NO_x	40 ppmv or 0.04 lb/MMBtu (30-day rolling average)	CEMS	
	H ₂ S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 33 - Vacuum Unit	VOC			Must comply with LDAR program
33H1 - Vacuum Furnace Heater	Onacity	10%		Air preheater package installed (II.B.11.c)
33111 - vacuum rumate meater	Opacity	10 /0	l	All preneater package installed (II.D.11.0)

Emissions Unit		mmary of Allowable Limits and Monitoring Require		
Emissions Unit	Parameter	Allowable Limit	Monitoring Approach	Comment
	PM_{10}	0.00051 lb/MMBtu		Stack test no later than October 31 of each year
	NO_x	0.02 lb/MMBtu 3-hour average		Stack test performed every 3 years
	NO _x	40 ppmv or 0.04 lb/MMBtu (30-day rolling average)	CEMS CEMS	CEMC leasted at plant first gas min draw /headen
Unit 45 - Asphalt Storage	H ₂ S VOC	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header Must comply with LDAR program
Unit 51 - Steam Systems	VOC			Must comply with LDAR program
Boiler #4	Opacity	10%		
2 3 45	HAPS	100/		Work practice standards
Boiler #5	Opacity NO _x	10% 0.03 lb/MMBtu 3-hour average		Stack test performed every 3 years
Boiler #8	Opacity	10%		stack test performed every 5 years
	PM_{10}	0.00051 lb/MMBtu		Stack test no later than October 31 of each year
	NO _x	0.02 lb/MMBtu 3-hour average		Stack test performed every 3 years
Boiler #9	H ₂ S Opacity	≤60 ppm (annual average) 10%		
Bollet #7	PM ₁₀	0.00051 lb/MMBtu		Stack test no later than October 31 of each year
	NO_x	0.02 lb/MMBtu 3-hour average		Stack test performed every 3 years
	H ₂ S	≤60 ppm (annual average)		
Boiler #10	Opacity	10% 0.00051 lb/MMBtu		Stack test no later than October 31 of each year
	PM_{10} NO_x	0.02 lb/MMBtu 3-hour average		Stack test no later than october 51 of each year Stack test performed every 3 years
	H ₂ S	≤60 ppm (annual average)		Sacretist personment every o years
Boiler #11	Opacity	10%		
	PM ₁₀	0.00051 lb/MMBtu		Stack test no later than October 31 of each year
	NO _x VOC	0.02 lb/MMBtu 3-hour average 0.004 lb/MMBtu		Stack test performed every 3 years Stack test performed every 3 years
	H ₂ S	≤60 ppm (annual average)		Stack test perior med every 3 years
Unit 56 - Wastewater	20	FF (Method 21, flow	Monitored at intervals no greater than 20 percent of the design carbon
Treatment	VOC	500 ppm (above background)	indicator	replacement interval
	VOC	500 ppm (above background)	Method 21	Semiannual inspections
	NO.		Visual	Manufacturalization
	VOC		inspections Visual	Monthly visual inspections
	VOC		inspections	Semiannual visual inspections
Unit 66 - Flares	Opacity	20%	_	•
66-1	H ₂ S, SO ₂ , flow	162 ppm (3-hr average), 500 lbs SO2 (24-hr rolling aver		South Flare -flow meters and gas combustion monitors install on gas
66-2	H ₂ S, SO ₂ , flow	162 ppm (3-hr average), 500 lbs SO2 (24-hr rolling aver	CEMS	North Flare - flow meters and gas combustion monitors installed on gas
Unit 68 - Tank Farm 68H2 - North In-Tank Asphalt	VOC			Must comply with LDAR Requirements
Heater	Opacity	10%		
	H ₂ S	≤60 ppm (annual average)		
68H3 - North In-Tank Asphalt	Ongoitus	100/		
Heater	Opacity H ₂ S	10% ≤60 ppm (annual average)		
68H4 - North In-Tank Asphalt	2-	(a. a.		
Heater	Opacity	10%		
68H5 - North In-Tank Asphalt	H ₂ S	≤60 ppm (annual average)		
Heater	Opacity	10%		
	H ₂ S	≤60 ppm (annual average)		
68H6 - North In-Tank Asphalt		100/		
Heater	Opacity NO _x	10% 0.098 lb/MMBtu 3-hour average		Stack test performed every 3 years
	H ₂ S	≤60 ppm (annual average)		Sacretist personment every o years
68H7 - North In-Tank Asphalt				
Heater	Opacity	10%		Stack test performed every 2 years
	NO _x H ₂ S	0.098 lb/MMBtu 3-hour average ≤60 ppm (annual average)		Stack test performed every 3 years
68H10 - North In-Tank Asphalt	20			
Heater	Opacity	10%		
	NO _x	0.098 lb/MMBtu 3-hour average		Stack test performed every 3 years
68H11 - North In-Tank Asphalt	H ₂ S	≤60 ppm (annual average)		
Heater	Opacity	10%		
	NO _x	0.098 lb/MMBtu 3-hour average		Stack test performed every 3 years
69H12 - North In Tank Asakak	H ₂ S	≤60 ppm (annual average)		
68H12 - North In-Tank Asphalt Heater	Opacity	10%		
	NO _x	0.098 lb/MMBtu 3-hour average		Stack test performed every 3 years
(OVIAO N1 1	H_2S	≤60 ppm (annual average)		
68H13 - North In-Tank Asphalt Heater	Opacity	10%		
Treater	NO _x	0.098 lb/MMBtu 3-hour average		Stack test performed every 3 years
	H ₂ S	≤60 ppm (annual average)		
Tanks 145 and 146		Tanks equipped with floating roofs		
Tanks 85, 86, 87, 88, 89, 90, 91,				Duoducto stared have TVD : 0.75 and add at
92, 93, 94, 95, 96, 97, 98, 99, 159, 323				Products stored have TVP > 0.75 psia and <11.1 psia. Tanks 85, 98, and 323 equipped with IFR. Tank 159 stores NGL.
		0% (except fot 15-minute period in 24-hours for line		ozo equipped with it is falls 137 stores itali.
Tank 79	Opacity	clearing		
East Tank Farm Portable		1,100 hours per rolling 12-month period, sulfur		
Generator Unit 87:		content ≤0.0015 % by weight		R307-401-8
Unit 87: Loading/Unloading	VOC			Must comply with LDAR Requirements
Louding/ Omodumg	VUC	600 hours total rolling 12-month period, sulfur content		Prose comply with LDAK Requirements
		≤0.0015% by weight	l	Testing and Maintenace only
Emergency Diesel Engines				

Emissions Unit	Parameter	,	Monitoring	Comment
		Allowable Limit	Approach	
Emergency Natural Gas				
Engines				
SO ₂ Emissions (all sources)		110.3 tons per rolling 12-month period 0.31 tons per day		
SO ₂ Emissions (All sources				
except 4V82 FCC and				
25FCC)		0.21 tons per day		
		74.9 tons per year		
PM ₁₀ All Sources		100.3 tons per rolling 12-month period		
PM ₁₀ Combustion Sources		47.5 tons per rolling 12-month period 0.13 tons per day		
NO _x All Sources		347.1 tons per rolling 12-month period 2.09 tons per day		