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July 26, 2017

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DAQ-2017-011661

Mr. John Jenks
Environmental Engineer
Utah Division of Air Quality
195 North 1950 West
P. O. Box 144820
Salt Lake City, Utah 84114-4820

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

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)			Uncontrolled (Tier 4)			Emission Reduction			Cost Effectiveness ($/ton)		
	Year	Rating	Rating	Replacement	$PM_{2.5}$ PTE	NO_X PTE	VOC PTE	$PM_{2.5}$ PTE	NO_X PTE	VOC PTE	$PM_{2.5}$ PTE	NO_X PTE	VOC PTE			
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

HollyFrontier Source ID	Source Description	MMBtu/hr	GJ/hr	Cost to Convert from ND to MD						SCR Capitol Cost (1991$)	SCR Cost (2017$)
				Capital Cost to Convert from ND to MD 1991$	Capital Cost 2017$	Capital Recovery Factor	Capital Recovery	O&M Cost	Total Annual Cost		
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 Emission Factor		SCR Emission Factor		
	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

HollyFrontier Woods Cross Refinery

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 costs 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, 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	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 Costs, $/year (Direct + Indirect)			
Direct Costs			
Operating Labor	$ 169,616	3% of capitol cost	
Raw materials	$ -		
Replacement Parts	$ 169,616	3% of capitol cost	
Total Direct Costs, $/year	**$ 339,232**		
Indirect Costs			
Overhead	$ 101,770	60% of labor costs	
Taxes, Insurance, and Administration	$ 226,155	4% of total installed cost	
Capitol Recovery	$ 743,314	10%, 15 years, CRF-.13147	
Total Indirect Costs, $/year	**$ 1,071,238**		
Total Annual Cost	**$ 1,410,471**		
Cost Effectiveness, $ per ton NO_x reduction	**$ 80,096.82**		

Assumptions:

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

HollyFrontier Woods Cross Refinery

NO_x Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 6H2

	MD/SCR Upgrade	Factor	Basis for Cost and Factor
Direct Costs:			
Puchased Equipment:			
Primary and Auxiliary Equipment (PE)	$ 1,185,656	Include costs 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**		
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			
Operating Labor	$ 79,360	3% of capitol cost	
Raw materials	$ -		
Replacement Parts	$ 79,360	3% of capitol cost	
Total Direct Costs, $/year	**$ 158,719**		
Indirect Costs			
Overhead	$ 47,616	60% of labor costs	
Taxes, Insurance, and Administration	$ 105,813	4% of total installed cost	
Capitol Recovery	$ 347,780	10%, 15 years, CRF-.13147	
Total Indirect Costs, $/year	**$ 501,208**		
Total Annual Cost	**$ 659,927**		
Cost Effectiveness, $ per ton NO_x reduction	**$ 170,825.76**		

Assumptions:

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

HollyFrontier Woods Cross Refinery

NO_x Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 6H3

	MD/SCR Upgrade	Factor	Basis for Cost and Factor
Direct Costs:			
Puchased Equipment:			
Primary and Auxiliary Equipment (PE)	$ 2,349,825	Include costs 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, 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 cost	
Raw materials	$ -		
Replacement Parts	$ 157,281	3% of capitol cost	
Total Direct Costs, $/year	**$ 314,562**		
Indirect Costs			
Overhead	$ 94,369	60% of labor costs	
Taxes, Insurance, and Administration	$ 209,708	4% of total installed cost	
Capitol Recovery	$ 689,257	10%, 15 years, CRF-.13147	
Total Indirect Costs, $/year	**$ 993,333**		
Total Annual Cost	**$ 1,307,895**		
Cost Effectiveness, $ per ton NO_x reduction	**$ 107,763.10**		

Assumptions:

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

HollyFrontier Woods Cross Refinery

NO_x Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 7H1

	MD/SCR	Factor	Basis for Cost
	Upgrade		**and Factor**
Direct Costs:			
Puchased Equipment:			
Primary and Auxiliary Equipment (PE)	$ 649,038	Include costs 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	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	$ 43,442	3% of capitol cost	
Raw materials	$ -		
Replacement Parts	$ 43,442	3% of capitol cost	
Total Direct Costs, $/year	**$ 86,884**		
Indirect Costs			
Overhead	$ 26,065	60% of labor costs	
Taxes, Insurance, and Administration	$ 57,923	4% of total installed cost	
Capitol Recovery	$ 190,378	10%, 15 years, CRF-.13147	
Total Indirect Costs, $/year	**$ 274,366**		
Total Annual Cost	**$ 361,250**		
Cost Effectiveness, $ per ton NO_x reduction	**$ 255,031.23**		

Assumptions:

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

HollyFrontier Woods Cross Refinery

NO_x Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 7H3

	MD/SCR Upgrade	Factor	Basis for Cost and Factor
Direct Costs:			
Puchased Equipment:			
Primary and Auxiliary Equipment (PE)	$ 2,189,269	Include costs 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 cost	
Raw materials	$ -		
Replacement Parts	$ 146,534	3% of capitol cost	
Total Direct Costs, $/year	**$ 293,069**		
Indirect Costs			
Overhead	$ 87,921	60% of labor costs	
Taxes, Insurance, and Administration	$ 195,379	4% of total installed cost	
Capitol Recovery	$ 642,162	10%, 15 years, CRF-.13147	
Total Indirect Costs, $/year	**$ 925,462**		
Total Annual Cost	**$ 1,218,531**		
Cost Effectiveness, $ per ton NO_x reduction	**$ 113,666.06**		

Assumptions:

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

HollyFrontier Woods Cross Refinery

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 costs 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	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 cost	
Raw materials	$ -		
Replacement Parts	$ 62,672	3% of capitol cost	
Total Direct Costs, $/year	**$ 125,343**		
Indirect Costs			
Overhead	$ 37,603	60% of labor costs	
Taxes, Insurance, and Administration	$ 83,562	4% of total installed cost	
Capitol Recovery	$ 274,648	10%, 15 years, CRF-.13147	
Total Indirect Costs, $/year	**$ 395,813**		
Total Annual Cost	**$ 521,156**		
Cost Effectiveness, $ per ton NO_x reduction	**$ 199,857.86**		

Assumptions:

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

HollyFrontier Woods Cross Refinery

NO_x Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 9H2

	MD/SCR Upgrade	Factor	Basis for Cost and Factor
Direct Costs:			
Puchased Equipment:			
Primary and Auxiliary Equipment (PE)	$ 622,092	Include costs 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**		
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 cost	
Raw materials	$ -		
Replacement Parts	$ 41,638	3% of capitol cost	
Total Direct Costs, $/year	**$ 83,277**		
Indirect Costs			
Overhead	$ 24,983	60% of labor costs	
Taxes, Insurance, and Administration	$ 55,518	4% of total installed cost	
Capitol Recovery	$ 182,474	10%, 15 years, CRF-.13147	
Total Indirect Costs, $/year	**$ 262,975**		
Total Annual Cost	**$ 346,252**		
Cost Effectiveness, $ per ton NO_x reduction	**$ 262,329.22**		

Assumptions:

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

HollyFrontier Woods Cross Refinery

NO_x Cost Analysis to Upgrade Process Heaters to MD then Add SCR - 10H1

	MD/SCR Upgrade	Factor	Basis for Cost and Factor
Direct Costs:			
Puchased Equipment:			
Primary and Auxiliary Equipment (PE)	$ 1,255,520	Include costs 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**		
Direct Installation			
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 cost	
Raw materials	$ -		
Replacement Parts	$ 84,036	3% of capitol cost	
Total Direct Costs, $/year	**$ 168,071**		
Indirect Costs			
Overhead	$ 50,421	60% of labor costs	
Taxes, Insurance, and Administration	$ 112,048	4% of total installed cost	
Capitol Recovery	$ 368,273	10%, 15 years, CRF-.13147	
Total Indirect Costs, $/year	**$ 530,742**		
Total Annual Cost	**$ 698,813**		
Cost Effectiveness, $ per ton NO_x reduction	**$ 164,446.87**		

Assumptions:

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

HollyFrontier Woods Cross Refinery

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 costs 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			
Operating Labor	$ 120,955	3% of capitol cost	
Raw materials	$ -		
Replacement Parts	$ 120,955	3% of capitol cost	
Total Direct Costs, $/year	**$ 241,911**		
Indirect Costs			
Overhead	$ 72,573	60% of labor costs	
Taxes, Insurance, and Administration	$ 161,274	4% of total installed cost	
Capitol Recovery	$ 530,067	10%, 15 years, CRF-.13147	
Total Indirect Costs, $/year	**$ 763,914**		
Total Annual Cost	**$ 1,005,825**		
Cost Effectiveness, $ per ton NO_x reduction	**$ 129,105.76**		

Assumptions:

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

HollyFrontier Woods Cross Refinery

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 costs 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 cost	
Raw materials	$ -		
Replacement Parts	$ 54,913	3% of capitol cost	
Total Direct Costs, $/year	**$ 109,825**		
Indirect Costs			
Overhead	$ 32,948	60% of labor costs	
Taxes, Insurance, and Administration	$ 73,217	4% of total installed cost	
Capitol Recovery	$ 240,646	10%, 15 years, CRF-.13147	
Total Indirect Costs, $/year	**$ 346,810**		
Total Annual Cost	**$ 456,636**		
Cost Effectiveness, $ per ton NO_x reduction	**$ 218,220.27**		

Assumptions:

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

ATTACHMENT 3

Monitoring Recommendations and Emission Limitations

Summary of Allowable Limits and Monitoring Requirements at the Woods Cross Refinery

Emissions Unit	Parameter	Allowable Limit	Monitoring Approach	Comment
Unit 4 - FCCU	VOC			Must comply with LDAR program
	CO	≤500 ppmv one-hour average at 0% O_2 1-hr avg.	CEMS	
	NO_x	≤40 ppmdv at 0% O_2 per 365-day rolling average	CEMS	
		≤80 ppmdv at 0% O_2 per 7-day rolling average	CEMS	
	SO_2	≤25 ppmdv at 0% O_2 per 365-day rolling average	CEMS	
		≤50 ppmdv at 0% O_2 per 7-day rolling average	CEMS	
	PM_{10}	0.50 lb/1000 lb coke burned	Stack Test, COMS/AMP	Stack test no later than October 31 of each year
4H1 - FCC Feed Heater	Opacity	10%		
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
4V82 FCC Scrubber	Opacity	15%	COMS	
	SO_2	0.05 tons per day		
	SO_2	17.7 tons per year		
Unit 6 - Catalytic Reforming Unit	VOC			Must comply with LDAR program
6H1-Reformer Charge Heater	Opacity	10%		
	PM_{10}			PM_{10} emissions based on 7.65 lb PM_{10}/MMscf
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
6H2 - Prefractionator Reboiler Heater	Opacity	10%		
	PM_{10}			PM_{10} emissions based on 7.65 lb PM_{10}/MMscf
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
6H3 - Reformer Reheater Furnace	Opacity	10%		
	PM_{10}			PM_{10} emissions based on 7.65 lb PM_{10}/MMscf
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 7 - Alkylation Unit	VOC			Must comply with LDAR program
7H1 - HF Alkylation Regeneration Furnace	Opacity	10%		
	PM_{10}			PM_{10} emissions based on 7.65 lb PM_{10}/MMscf
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
7H3 - HF Alkylation Depropanizer Reboiler	Opacity	10%		
	PM_{10}			PM_{10} emissions based on 7.65 lb PM_{10}/MMscf
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 8 - Crude Unit	VOC			Must comply with LDAR program
8H2 - Crude Furnace	Opacity	10%		
	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		Stack test performed every 3 years
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 9 - Distillate Hydrosulfurization Unit	VOC			Must comply with LDAR program
9H1-DHDS Reactor Charge Heater	Opacity	10%		
	PM_{10}			PM_{10} emissions based on 7.65 lb PM_{10}/MMscf
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
9H2-DHDS Stripper Reboiler	Opacity	10%		
	PM_{10}			PM_{10} emissions based on 7.65 lb PM_{10}/MMscf
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 10 - Solvent Deasphalting Unit	VOC			Must comply with LDAR program
10H1 - Asphalt Mix Heater	Opacity	10%		
	PM_{10}			
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
10H2 - Hot Oil 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	CEMS	Stack test performed every 3 years
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 11 - Straight Run Gas Plant	VOC			Must comply with LDAR program
11H1 - SRGP Depentanizer Reboiler	Opacity	10%		
	PM_{10}			PM_{10} emissions based on 7.65 lb PM_{10}/MMscf
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 12- Naphtha Hydrodesulphurization Unit	VOC			Must comply with LDAR program
12H1 - NHDS Reactor Charge Furnace	Opacity	10%		
	PM_{10}			PM_{10} emissions based on 7.65 lb PM_{10}/MMscf
	NO_x	0.10 lb/MMBtu 3-hour average		Stack test performed every 3 years
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 13 - Isomerization Unit	VOC			
13H1 - Isomerization Reactor Feed Furnace	Opacity	10%		
	PM_{10}			PM_{10} emissions based on 7.65 lb PM_{10}/MMscf
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 16 - Amine Treatment Unit	VOC			Must comply with LDAR program
Unit 17 - Sulfur Recovery Unit	VOC			Must comply with LDAR program
	Sulfur	≤20 long tons per day		
	Sulfur	95% recovery on a 30-day average except during SSM		Compliance based on flow rate and H_2S concentration in the feed and SO_2 CEMS

Summary of Allowable Limits and Monitoring Requirements at the Woods Cross Refinery

Emissions Unit	Parameter	Allowable Limit	Monitoring Approach	Comment
	Sulfur	≤1.6 tn/day except during SSM		
	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%		
	PM_{10}	0.00051 lb/MMBtu		
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 20 - Gas Oil 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_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
20H2-Fractionator Charge Heater	Opacity	10%		
	PM_{10}	0.00051 lb/MMBtu		Stack test no later than October 31 of each year
	H_2S	≤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		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_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 21 - NaSH Sour Gas Treatment Unit	VOC			Must comply with LDAR program
Unit 22 - Sour Water 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
	H_2S	≤60 ppm (annual average)		
Unit 24- Crude Unit	VOC			Must comply with LDAR program
24H1 - Crude Unit Furnace	Opacity	10%		
	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_2S	≤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% O_2 per 365-day rolling average	CEMS	
		≤80 ppmdv at 0% O_2 per 7-day rolling average	CEMS	
	SO_2	≤25 ppmdv at 0% O_2 per 365-day rolling average	CEMS	
		≤50 ppmdv at 0% O_2 per 7-day rolling average	CEMS	
	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	10%		
	PM_{10}	0.00051 lb/MMBtu		
	NO_x	0.04 lb/MMBtu 3-hour average		Stack test performed every 3 years
	H_2S	≤60 ppm (annual average)		
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	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 - 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
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 28 - Sour Water Stripping Unit	VOC			Must comply with LDAR program
Unit 30 - Hydrogen Plant	VOC			Must comply with LDAR program
30H1 - 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_2S	≤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_2S	≤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	Opacity	10%		Air preheater package installed (II.B.11.c)

Summary of Allowable Limits and Monitoring Requirements at the Woods Cross Refinery

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	
	H_2S	≤60 ppm (annual average)	CEMS	CEMS located at plant fuel gas mix drum/header
Unit 45 - Asphalt Storage	VOC			Must comply with LDAR program
Unit 51 - Steam Systems	VOC			Must comply with LDAR program
Boiler #4	Opacity	10%		
	HAPS			Work practice standards
Boiler #5	Opacity	10%		
	NO_x	0.03 lb/MMBtu 3-hour average		Stack test performed every 3 years
Boiler #8	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
	H_2S	≤60 ppm (annual average)		
Boiler #9	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
	H_2S	≤60 ppm (annual average)		
Boiler #10	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
	H_2S	≤60 ppm (annual average)		
Boiler #11	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
	VOC	0.004 lb/MMBtu		Stack test performed every 3 years
	H_2S	≤60 ppm (annual average)		
Unit 56 - Wastewater Treatment	VOC	500 ppm (above background)	Method 21, flow indicator	Monitored at intervals no greater than 20 percent of the design carbon replacement interval
	VOC	500 ppm (above background)	Method 21	Semiannual inspections
	VOC		Visual inspections	Monthly visual inspections
	VOC		Visual inspections	Semiannual visual inspections
Unit 66 - Flares	Opacity	20%		
66-1	H_2S, SO_2, flow	162 ppm (3-hr average), 500 lbs SO2 (24-hr rolling aver	CEMS	South Flare -flow meters and gas combustion monitors install on gas
66-2	H_2S, 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	VOC			Must comply with LDAR Requirements
68H2 - North In-Tank Asphalt Heater	Opacity	10%		
	H_2S	≤60 ppm (annual average)		
68H3 - North In-Tank Asphalt Heater	Opacity	10%		
	H_2S	≤60 ppm (annual average)		
68H4 - North In-Tank Asphalt Heater	Opacity	10%		
	H_2S	≤60 ppm (annual average)		
68H5 - North In-Tank Asphalt Heater	Opacity	10%		
	H_2S	≤60 ppm (annual average)		
68H6 - North In-Tank Asphalt Heater	Opacity	10%		
	NO_x	0.098 lb/MMBtu 3-hour average		Stack test performed every 3 years
	H_2S	≤60 ppm (annual average)		
68H7 - North In-Tank Asphalt Heater	Opacity	10%		
	NO_x	0.098 lb/MMBtu 3-hour average		Stack test performed every 3 years
	H_2S	≤60 ppm (annual average)		
68H10 - North In-Tank Asphalt Heater	Opacity	10%		
	NO_x	0.098 lb/MMBtu 3-hour average		Stack test performed every 3 years
	H_2S	≤60 ppm (annual average)		
68H11 - North In-Tank Asphalt Heater	Opacity	10%		
	NO_x	0.098 lb/MMBtu 3-hour average		Stack test performed every 3 years
	H_2S	≤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
	H_2S	≤60 ppm (annual average)		
68H13 - North In-Tank Asphalt Heater	Opacity	10%		
	NO_x	0.098 lb/MMBtu 3-hour average		Stack test performed every 3 years
	H_2S	≤60 ppm (annual average)		
Tanks 145 and 146		Tanks equipped with floating roofs		
Tanks 85, 86, 87, 88, 89, 90, 91, 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.
Tank 79	Opacity	0% (except fot 15-minute period in 24-hours for line clearing		
East Tank Farm Portable Generator		1,100 hours per rolling 12-month period, sulfur content ≤0.0015 % by weight		R307-401-8
Unit 87: Loading/Unloading	VOC			Must comply with LDAR Requirements
Emergency Diesel Engines		600 hours total rolling 12-month period, sulfur content ≤0.0015% by weight		Testing and Maintenace only

Summary of Allowable Limits and Monitoring Requirements at the Woods Cross Refinery

Emissions Unit	Parameter	Allowable Limit	Monitoring Approach	Comment
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		