Prevention of Significant Deterioration
Greenhouse Gas Permit Application
Domestic Crude Project

Flint Hills Resources Corpus Christi, LLC
West Refinery
Corpus Christi, Nueces County

March 2014

STATE OF TEXAS
KRIS L. KIRCHNER
89354
LICENSED
PROFESSIONAL ENGINEER

Kris L. Kirchner
3/27/2014

Approved by:

Kris L. Kirchner

Kris L. Kirchner, P.E.
Senior Consulting Engineer

Waid Corporation dba Waid Environmental
Certificate of Registration No. F-58

www.waid.com

Austin Office
10800 Pecan Park Blvd., Suite 300
Austin, Texas 78750
512.255.9999 • 512.255.8780 FAX

Houston Office
2600 South Shore Blvd., Suite 300
League City, Texas 77573
281.333.9990 • 512.255.8780 FAX

Midland Office
24 Smith Road, Suite 304
Midland, Texas 79705
432.682.9999 • 432.682.7774 FAX

TABLE OF CONTENTS

Section 1.0

Company Information

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

Important Note: The agency requires that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued and no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: Flint Hills Resources Corpus Christi, LLC		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: Valerie Pompa		
Title: Vice President and Manufacturing Manager		
Mailing Address: P.O. Box 2608		
City: Corpus Christi	State: TX	ZIP Code: 78403
Telephone No.: 361.242.8358	Fax No.: 361.242.4840	E-mail Address: valerie.pompa@fhr.com
C. Technical Contact Name: Daren Knowles		
Title: Strategic Permitting Projects Manager		
Company Name: Flint Hills Resources Corpus Christi, LLC		
Mailing Address: P.O. Box 2608		
City: Corpus Christi	State: TX	ZIP Code: 78403
Telephone No.: 361.242.8301	Fax No.: 361.242.8743	E-mail Address: daren.knowles@fhr.com
D. Site Name: Corpus Christi West Refinery		
E. Area Name/Type of Facility: West Refinery		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Petroleum Refining		
Principal Standard Industrial Classification Code (SIC): 2911		
Principal North American Industry Classification System (NAICS): 324110		
G. Projected Start of Construction Date: 09/2015		
Projected Start of Operation Date: 09/2016		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 2825 Suntide Road		
City/Town: Corpus Christi	County: Nueces	ZIP Code: 78409
Latitude (nearest second): 27° 49' 38"	Longitude (nearest second): - 97° 31' 32"	

Section 2.0

Project Overview and Description

Flint Hills Resources Corpus Christi, LLC (FHR) owns and operates a refinery in Corpus Christi called the West Refinery. FHR is proposing a project at the West Refinery that would allow the refinery to process a larger percentage of domestically produced crude. The domestic crude is much lighter than foreign crude. Therefore, an additional process unit and other equipment are being constructed to process more lighter-end products. The project would also modestly increase (by approximately 7%) the total crude processing capacity at the West Refinery.

Summary of Project

There are two types of changes—described in more detail below—proposed as part of this project: (1) construction of new emission units to be authorized by this permitting action; and (2) changes to existing emission units to be authorized by this permitting action.

1. Construction of New Emission Units

As part of the project, FHR is proposing to construct the following new emission units:

- A new process unit called the Saturates Gas (Sat Gas) No. 3 Unit that will include a new hot oil heater and equipment piping fugitive components. The new hot oil heater will be equipped with energy efficient, low NO_X burners and an air preheat system, selective catalytic reduction (SCR) to reduce nitrogen (NO_X) emissions, and a catalyst bed to control carbon monoxide (CO) and volatile organic compound (VOC) emissions.
- A new cooling tower in an area of the plant commonly referred to as the Mid-Plant area.
- New equipment piping fugitive components in several existing process units.

2. Changes to Existing Emission Units

As part of the project, FHR is proposing the following changes to existing emission units:

- An increase in the permitted firing duty of the CCR Hot Oil Heater. In addition, new energy efficient, low NO_X burners, a new air preheat system, and a SCR to reduce NO_X emissions will be installed on the CCR Hot Oil Heater.
- Conversion of the current Gas Oil Hydrotreating Unit (GOHT) to a Distillate Hydrotreating Unit (DHT).
- An increase in maintenance, startup, and shutdown (MSS) emissions as a result of new equipment being installed.

In addition, there will be increases in actual emissions for some emission units as a result of increased utilization or debottlenecking. Finally, while there will be no physical change at the marine loading area or to tanks 40FB4010 and 40FB4011 as part of this project, FHR will increase the annual marine loading throughput of naphtha and gasoline and tank crude oil throughput above existing permitted levels. Emissions increases from these actions are accounted for in this permit application. FHR has submitted a separate minor NSR permit application to TCEQ for the increased throughputs that includes a state BACT analysis for the marine loading operation and crude oil tanks. However, the increase in annual marine loading and tank crude throughput are not modifications for federal PSD, so GHG BACT is not required for the marine loading operations or tanks.

A table is provided at the end of this section showing the changes proposed for each emission unit associated with this project.

Summary of Proposed BACT Emission Limits

Based on the EPA recommended five-step, top-down process to determine BACT for GHG emissions, FHR is proposing the following as BACT emission limits:

Source	Proposed Emission Controls	Proposed Emission Limit
Sat Gas No. 3 Hot Oil Heater	Implement energy efficient design and operating practices. The heater is designed for 92% efficiency.	236,242 tons CO_2e total per 365-days (rolling)
Mid Plant Cooling Tower No. 2	Implement cooling tower monitoring program	Work practice standard
Equipment Leak Fugitives	Implement enhanced LDAR monitoring	Work practice standard
CCR Hot Oil Heater	Implement energy efficient design and operating practices. The heater is designed for 91% efficiency.	63,193 tons CO_2e total per 365-days (rolling)
Various Planned Maintenance, Start-up, and Shutdown Activities	Minimize GHG degassing emissions through good operational practices	Work practice standard

FIN	EPN	Description	PSD Source Type	Proposal	Is there a Physical Change or Change in Method of Operation Causing an Emission Increase?	Is the Source Subject to BACT Review?	Proposed Controls for Greenhouse Gas Pollutants
SATGASHTR	SATGASHTR	Sat Gas No. 3 Heater	New	New source as part of building new Saturates Gas Plant No. 3 Unit. Installation of SCR, CO/VOC catalyst bed, energy efficient low NOx burners, and air preheat system.	Yes	Yes	Implement energy efficient design and operating practices.
39BA3901	39BA3901	CCR Hot Oil Heater	Modified	Increase in fired duty from 90 MMBtu/hr to 123.6 MMBtu/hr (HHV). Installation of SCR, new energy efficient low NOx burners, and air preheat system.	Yes	Yes	Implement energy efficient design and operating practices.
Various Boilers	Various Boilers	Various boilers seeing increased utilization.	Affected Downstream - increased utilization	Increase in actual emissions as a result of increased utilization due to increased steam demand. No change to permitted duty under existing TCEQ permit.	No	No	N/A
37BA2	KK-3	37BA2 DHT Stripper Reboiler	Affected Downstream - debottlenecking	Increase in actual emissions. It is not clear whether such increases should be characterized as resulting from debottlenecking or increased utilization. We assume, conservatively, that the increase is the result of debottlenecking. No change to permitted duty under existing TCEQ permit.	No	No	N/A
45BD3	V-8	API Separator Flare	Affected Downstream - increased utilization	Increase in actual emissions at Monroe API Separator controlled by the API Separator Flare as a result of increasing the amount of wastewater going to the separator. The increased amount of wastewater will not exceed the throughput limit under the existing TCEQ permit.	No	No	N/A
LW-8	VCS-1	Marine Vapor Combustor	Affected Downstream - increased utilization	Increase in annual loading rate of naphtha and gasoline.	No	No	N/A
F-SATGAS3	F-SATGAS3	Sat Gas No. 3 Fugitives	New	New fugitive piping components (i.e. valves, flanges, etc.) as part of building new Saturates Gas Plant #3.	Yes	Yes	Implement enhanced LDAR monitoring
14-UDEX	F-14-UDEX	UDEX Fugitives	New	Addition of new fugitive piping components (i.e. valves, flanges, etc.) as part of process changes.	Yes	Yes	Implement enhanced LDAR monitoring
37	F-37	DHT Fugitives	New	Addition of new fugitive piping components (i.e. valves, flanges, etc.) as part of process changes.	Yes	Yes	Implement enhanced LDAR monitoring
39	F-39	NHT/CCR Fugitives	New	Addition of new fugitive piping components (i.e. valves, flanges, etc.) as part of process changes.	Yes	Yes	Implement enhanced LDAR monitoring
40	F-40	West Crude Fugitives	New	Addition of new fugitive piping components (i.e. valves, flanges, etc.) as part of process changes.	Yes	Yes	Implement enhanced LDAR monitoring

FIN	EPN	Description	PSD Source Type	Proposal	Is there a Physical Change or Change in Method of Operation Causing an Emission Increase?	Is the Source Subject to BACT Review?	Proposed Controls for Greenhouse Gas Pollutants
42	F-42	Mid Crude Fugitives	New	Addition of new fugitive piping components (i.e. valves, flanges, etc.) as part of process changes.	Yes	Yes	Implement enhanced LDAR monitoring
P-GB	F-GB	Gasoline Blender Fugitives	New	Addition of new fugitive piping components (i.e. valves, flanges, etc.) as part of process changes.	Yes	Yes	Implement enhanced LDAR monitoring
P-VOC	F-TK-VOC	VOC Tank/Loading Fugitives	New	Addition of new fugitive piping components (i.e. valves, flanges, etc.) as part of process changes.	Yes	Yes	Implement enhanced LDAR monitoring
44EF2	F-S-202	Mid-Plant Cooling Tower No. 2	New	New cooling tower	Yes	Yes	Implement cooling tower monitoring and repair program
08FB142	FB142	Tank 08FB142	Affected Downstream - increased utilization	Increase in actual emissions as a result of increasing the throughput of crude oil in the tanks.	No	No	N/A
08FB147	FB147	Tank 08FB147					
08FB137	FB137	Tank 08FB137					
40FB4010	FB4010	Tank 40FB4010					
40FB4011	FB4011	Tank 40FB4011					
MSSFUGS-DC	MSSFUGS-DC	Miscellaneous Fugitives from Domestic Crude Project MSS Activities	New	New MSS emissions as a result of constructing new Sat Gas 3 Unit and other changes to existing equipment.	Yes	Yes	Minimize degassing through good operational practices

Section 3.0

PREVENTION OF SIGNIFICANT DETERIORATION (PSD) APPLICABILITY

Applicability

FHR's West Refinery is a petroleum refinery and an existing major source of GHG emissions because the potential to emit GHGs prior to the modifications associated with this project is greater than 100 tons/yr GHG on a mass basis and greater than 100,000 tons/yr CO_2e. As shown in the following table and in Table 2-F provided at the end of this section, the project is a major modification for GHGs because the emissions increases resulting from the project, without considering any emissions decreases, are greater than 75,000 tons/yr CO_2e and 0 tons/yr GHG on a mass basis.

This project—including construction of the new emission units, changes to existing emission units, and emissions increases from upstream and downstream affected units—will not trigger federal PSD for any non-GHG new source review (NSR)-regulated pollutants. In fact, the overall project will result in decreased emissions of non-GHG pollutants, with the exception of ammonia. Therefore, for non-GHG pollutants, construction of new emission units and changes to existing emission units are subject only to Texas minor NSR requirements. Emission information for these non-GHG NSR pollutants is set forth in the relevant Texas minor NSR permit applications, and is not provided in this GHG-only application.

Emission Calculation Methods

Existing modified sources—that is, those sources undergoing a physical change or change in method of operation—may use the actual-to-projected actual test of 40 C.F.R. § 52.21(a)(2)(iv) to determine if there will be an emission increase that triggers PSD for GHG. Nevertheless, and simply for ease of calculation, for existing modified sources the source's actual emissions for 2011 and 2012 are compared voluntarily to its future potential to emit to calculate emission increases. For new sources, the future potential to emit after the project is fully operational is used to establish the emissions increase. For those sources that are not new or modified but are affected upstream or downstream of the project due to an increase in utilization rate, an incremental increase in actual emissions is calculated based on the expected increased utilization rate. For those sources that are not new or modified but are affected upstream or downstream of the project due to debottlenecking, EPA in the *Holcim* memorandum takes the position that the 2-year actual emissions from the most recent two years and the future potential to emit after the project must be evaluated to determine each source's emissions increase.[1] For the Marine Vapor Combustor (EPN VCS-1), FHR uses the 2-year actual emissions and potential to emit based only on the loading of naphtha and gasoline and heavier materials since those are the only materials for which FHR is proposing to increase the throughput.

[1] FHR does not agree that the actual-to-potential test is mandated by the PSD regulations for all changes that can be characterized as "debottlenecking," but FHR will conservatively follow the EPA guidance in this permit application.

Pollutant	PSD Emissions Increase (tons/yr)	PSD Threshold (tons/yr)
Carbon Dioxide (CO_2)	358,647	N/A
Methane (CH_4)	33	N/A
Nitrous Oxide (N_2O)	2	N/A
Total GHG (mass basis)	358,682	0
CO_2e	359,991	75,000

TCEQ

TABLE 2F
PROJECT EMISSIONS INCREASE

Pollutant [(1)]**:** GHG (mass basis)		**Permit:**	N/A
Baseline Period: 2011	**to** 2012		

	Affected or Modified Facilities [(2)] FIN	EPN	Permit NO.	Actual Emissions [(3)] (tons/yr)	B Baseline Emissions [(4)] (tons/yr)	A Proposed Emissions [(5)] (tons/yr)	Projected Actual Emissions (ton/yr)	Difference (A-B) [5] (tons/yr)	Correction [(7)] (ton/yr)	Project Increase [(8)] (tons/yr)
1	SATGASHTR	SATGASHTR	N/A	0	0	236009	N/A	236009	N/A	236009
2	39BA3901	JJ-4	N/A	20374	20374	62894	N/A	42520	N/A	42520
3	Various Boilers	Various Boilers	N/A	N/A	N/A	50481	N/A	50481	N/A	50481
4	37BA2	KK-3	N/A	11465	11465	37282	N/A	25817	N/A	25817
5	45BD3	V-8	N/A	N/A	N/A	335	N/A	335	N/A	335
6	LW-8	VCS-1	N/A	N/A	N/A	3282	N/A	3282	N/A	3282
7	F-SATGAS3	F-SATGAS3	N/A	0.00	0.00	6.44	N/A	6.44	N/A	6.44
8	14-UDEX	F-14-UDEX	N/A	0.00	0.00	0.01	N/A	0.01	N/A	0.01
9	37	F-37	N/A	0.00	0.00	0.15	N/A	0.15	N/A	0.15
10	39	F-39	N/A	0.00	0.00	0.06	N/A	0.06	N/A	0.06
11	40	F-40	N/A	0.00	0.00	0.32	N/A	0.32	N/A	0.32
12	42	F-42	N/A	0.00	0.00	0.91	N/A	0.91	N/A	0.91
						PAGE SUBTOTAL: [(9)]				358,452
								Total		

TABLE 2F
PROJECT EMISSIONS INCREASE

Pollutant [1]:	GHG (mass basis)	**Permit:**	N/A
Baseline Period:	2011 **to** 2012		

	Affected or Modified Facilities [2] FIN	EPN	Permit NO.	Actual EGissions (3) (tons/yr)	B Baseline Emissions [4] (ton/yr)	A Proposed Emissions [5] (tons/yr)	Projected Actual Emissions (ton/yr)	Difference (A-B) [5] (tons/yr)	Correction [7] (ton/yr)	Project Increase [8] (tons/yr)
13	P-GB	F-GB	N/A	0.00	0.00	0.04	N/A	0.04	N/A	0.04
14	P-VOC	F-TK-VOC	N/A	0.00	0.00	0.29	N/A	0.29	N/A	0.29
15	44EF2	F-S-202	N/A	0.00	0.00	0.55	N/A	0.55	N/A	0.55
16	08FB142	FB142	N/A	N/A	N/A	1.33	N/A	1.33	N/A	1.33
17	08FB147	FB147	N/A							
18	08FB137	FB137	N/A							
19	40FB4010	FB4010	N/A							
20	40FB4011	FB4011	N/A							
21	MSSFUGS-DC	MSSFUGS-DC	N/A	0.00	0.00	228	N/A	228	N/A	228
22										
23										
24										
PAGE SUBTOTAL: [9]										230
								Total		358,682

TABLE 2F
PROJECT EMISSIONS INCREASE

Pollutant [(1)]**:**	CO_2e	**Permit:**	N/A
Baseline Period:	2011 **to** 2012		

	Affected or Modified Facilities [(2)] FIN	EPN	Permit NO.	Actual Emissions [(3)] (tons/yr)	B Baseline Emissions [(4)] (tons/yr)	A Proposed Emissions [(5)] (tons/yr)	Projected Actual Emissions (ton/yr)	Difference (A-B) [5] (tons/yr)	Correction [(7)] (ton/yr)	Project Increase [(8)] (tons/yr)
1	SATGASHTR	SATGASHTR	N/A	0	0	236242	N/A	236242	N/A	236242
2	39BA3901	JJ-4	N/A	20484	20484	63193	N/A	42709	N/A	42709
3	Various Boilers	Various Boilers	N/A	N/A	N/A	50713	N/A	50713	N/A	50713
4	37BA2	KK-3	N/A	11523	11523	37454	N/A	25930	N/A	25930
5	45BD3	V-8	N/A	N/A	N/A	362	N/A	362	N/A	362
6	LW-8	VCS-1	N/A	N/A	N/A	3551	N/A	3551	N/A	3551
7	F-SATGAS3	F-SATGAS3	N/A	0	0	161	N/A	161	N/A	161
8	14-UDEX	F-14-UDEX	N/A	0	0	0.2	N/A	0.2	N/A	0.2
9	37	F-37	N/A	0	0	4	N/A	4	N/A	4
10	39	F-39	N/A	0	0	1	N/A	1	N/A	1
11	40	F-40	N/A	0	0	8	N/A	8	N/A	8
12	42	F-42	N/A	0	0	23	N/A	23	N/A	23
							PAGE SUBTOTAL: [(9)]			359706
								Total		

TCEQ

TABLE 2F
PROJECT EMISSIONS INCREASE

Pollutant [1]:	CO_2e	**Permit:**	N/A
Baseline Period:	2011	**to**	2012

	Affected or Modified Facilities [2] FIN	EPN	Permit NO.	Actual Emissions [3] (tons/yr)	B Baseline Emissions [4] (ton/yr)	A Proposed Emissions [5] (tons/yr)	Projected Actual Emissions (ton/yr)	Difference (A-B) [5] (tons/yr)	Correction [7] (ton/yr)	Project Increase [8] (tons/yr)
13	P-GB	F-GB	N/A	0	0	1	N/A	1	N/A	1
14	P-VOC	F-TK-VOC	N/A	0	0	7	N/A	7	N/A	7
15	44EF2	F-S-202	N/A	0	0	14	N/A	14	N/A	14
16	08FB142	FB142	N/A							
17	08FB147	FB147	N/A							
18	08FB137	FB137	N/A	N/A	N/A	33	N/A	33	N/A	33
19	40FB4010	FB4010	N/A							
20	40FB4011	FB4011	N/A							
21	MSSFUGS-DC	MSSFUGS-DC	N/A	0	0	230	N/A	230	N/A	230
22										
23										
24										
							PAGE SUBTOTAL: [9]			286
								Total		359991

TABLE 2F
PROJECT EMISSION INCREASE

All emissions must be listed in tons per year (tpy). The same baseline period must apply for all facilities for a given NSR pollutant.

1. Individual Table 2F=s should be used to summarize the project emission increase for each criteria pollutant.
2. Emission Point Number as designated in NSR Permit or Emissions Inventory.
3. All records and calculations for these values must be available upon request.
4. Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.
5. If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement.
6. Proposed Emissions (column B) Baseline Emissions (column A).
7. Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement.
8. Obtained by subtracting the correction from the difference. Must be a positive number.
9. Sum all values for this page.

Pollutant:		Line		Type[1]	
Explanation:					

1 Type of note. Generally would be baseline adjustment, basis for projected actual, or basis for correction (what could have been accommodated).

Section 4.0

PROCESS DESCRIPTION AND EMISSIONS DATA

Process descriptions for each of the process units affected by the project are provided below. A table (Table 1a) summarizing the proposed emission rates is provided in this section along with the emission rate calculations for the emission units affected by this project.

The table below shows the carbon dioxide (CO_2), Methane (CH_4), and nitrous oxide (N_2O) emission factors for natural gas and the refinery fuel gas systems that were used in the emission rates calculations for process heaters and boilers. Each CO_2 emission factor was calculated using Tier III methodology (Equation C-5) in 40 C.F.R. Part 98, Subpart C and actual carbon content, molecular weight, and higher heating values for purchased natural gas and the CCR, 90#, and Mid Plant refinery fuel gas systems from 2011, 2012, and 2013. To account for variability in the carbon content, molecular weight, and higher heating values of each of the different fuel gases, the CO_2 factor for each was determined by calculating an average lb CO_2/MMBtu factor using the carbon content, molecular weight, and higher heating value data for 2011, 2012, and 2013 and adding two standard deviations to the average. CH_4 and N_2O emission factors are from Table C-2 from 40 C.F.R. Part 98, Subpart C, and for all fuel gas systems other than purchased natural gas, the emission factor for “Petroleum” is used.

Fuel Gas System	CO_2 Emission Factor (lb/MMBtu)	CH_4 Emission Factor (kg/MMBtu)	N_2O Emission Factor (kg/MMBtu)
Purchased Natural Gas	119.74	1.0×10^{-3}	1.0×10^{-4}
CCR Refinery Fuel Gas System	116.17	3.0×10^{-3}	6.0×10^{-4}
90# Refinery Fuel Gas System	119.29	3.0×10^{-3}	6.0×10^{-4}
Mid Plant Refinery Fuel Gas System	120.05	3.0×10^{-3}	6.0×10^{-4}

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: December 2012; Revised March 2014	**Permit No.:** N/A	**Regulated Entity No.:** RN100235266
Area Name: Corpus Christi West Refinery		**Customer Reference No.:** CN603741463

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA				
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate
EPN (A)	FIN (B)	NAME (C)		TPY (B)
SATGASHTR	SATGASHTR	Sat Gas No. 3 Hot Oil Heater	Carbon Dioxide (CO2)	236004.1
			Methane (CH4)	4.3
			Nitrous Oxide (N2O)	0.43
			Carbon Dioxide Equivalent (CO2e)	236242.2
JJ-4	39BA3901	CCR Hot Oil Heater	Carbon Dioxide (CO2)	62890.1
			Methane (CH4)	3.58
			Nitrous Oxide (N2O)	0.72
			Carbon Dioxide Equivalent (CO2e)	63193.0

EPN = Emission Point Number
FIN = Facility Identification Number

TCEQ-10153 (Revised 0408)
This form is for use by sources subject to air quality
permit requirements and may be revised periodically. [APDG 5178v4]

Printed 03/17/2014 15:10

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	**December 2012; Revised February 2014**	**Permit No.:** N/A	**Regulated Entity No.:** RN100235266
Area Name:	**Corpus Christi West Refinery**		**Customer Reference No.:** CN603741463

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA				
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**
EPN (A)	**FIN (B)**	**NAME (C)**		**TPY (B)**
F-SATGAS3	F-SATGAS3	Sat Gas No. 3 Fugitives	Methane (CH4)	Work Practice Standard
			Carbon Dioxide Equivalent (CO2e)	Work Practice Standard
14-UDEX	F-14-UDEX	Udex Fugitives	Methane (CH4)	Work Practice Standard
			Carbon Dioxide Equivalent (CO2e)	Work Practice Standard
37	F-37	DHT Fugitives	Methane (CH4)	Work Practice Standard
			Carbon Dioxide Equivalent (CO2e)	Work Practice Standard
39	F-39	NHT/CCR Fugitives	Methane (CH4)	Work Practice Standard
			Carbon Dioxide Equivalent (CO2e)	Work Practice Standard
40	F-40	West Crude Fugitives	Methane (CH4)	Work Practice Standard
			Carbon Dioxide Equivalent (CO2e)	Work Practice Standard

EPN = Emission Point Number
FIN = Facility Identification Number

TCEQ-10153 (Revised 0408)
This form is for use by sources subject to air quality
permit requirements and may be revised periodically. [APDG 5178v4]

Printed 02/12/2014 06:16

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: December 2012; Revised February 2014	**Permit No.:** N/A	**Regulated Entity No.:** RN100235266	
Area Name: Corpus Christi West Refinery		**Customer Reference No.:** CN603741463	

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA				
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**
EPN (A)	**FIN (B)**	**NAME (C)**		**TPY (B)**
F-42	42	Mid Crude Fugitives	Methane (CH4)	Work Practice Standard
			Carbon Dioxide Equivalent (CO2e)	Work Practice Standard
P-GB	F-GB	Gasoline Blender Fugitives	Methane (CH4)	Work Practice Standard
			Carbon Dioxide Equivalent (CO2e)	Work Practice Standard
P-VOC	F-TK-VOC	VOC Tank/Loading Fugitives	Methane (CH4)	Work Practice Standard
			Carbon Dioxide Equivalent (CO2e)	Work Practice Standard
44EF2	F-S-202	Mid-Plant Cooling Tower No. 2	Methane (CH4)	Work Practice Standard
			Carbon Dioxide Equivalent (CO2e)	Work Practice Standard

EPN = Emission Point Number
FIN = Facility Identification Number

TCEQ-10153 (Revised 0408)
This form is for use by sources subject to air quality
permit requirements and may be revised periodically. [APDG 5178v4]

Printed 02/12/2014 06:16

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	**December 2012; Revised February 2014**	**Permit No.:** N/A	**Regulated Entity No.:** RN100235266
Area Name:	**Corpus Christi West Refinery**		**Customer Reference No.:** CN603741463

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA				
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate
EPN (A)	FIN (B)	NAME (C)		TPY (B)
MSSFUGS-DC	MSSFUGS-DC	Miscellaneous Fugitives from MSS Activities from Domestic Crude Project	Carbon Dioxide (CO2)	Work Practice Standard
			Methane (CH4)	Work Practice Standard
			Nitrous Oxide (N2O)	Work Practice Standard
			Carbon Dioxide Equivalent (CO2e)	Work Practice Standard

EPN = Emission Point Number
FIN = Facility Identification Number

TCEQ-10153 (Revised 0408)
This form is for use by sources subject to air quality
permit requirements and may be revised periodically. [APDG 5178v4]

Printed 02/12/2014 06:16

CCR/NHT UNITS

The Continuous Catalytic Regeneration (CCR) and Naphtha Hydrotreater (NHT) Units are existing process units at the West Refinery. FHR is proposing to install new equipment piping components and make process changes at the CCR and NHT Units which require an increase in the firing duty of the CCR Hot Oil Heater (39BA3901) from 90 MMBtu/hr (HHV) to 123.6 MMBtu/hr (HHV).

General Process Description

The purpose of the NHT Unit is to catalytically remove sulfur, nitrogen and saturate olefins from the naphtha feed to the CCR unit. Hydrotreating removes impurities from a petroleum fraction by contacting the stream with hydrogen in the presence of a catalyst at high temperatures and pressures. The CCR Unit converts naphtha to aromatics consisting primarily of benzene, toluene, and xylene. Aromatics are produced by the dehydrogenation of naphthenes and cyclization of paraffins. The dehydrogenation process also produces a hydrogen by-product. The aromatic compounds are then separated and further processed in other units. Hydrogen is consumed as fuel gas or used as feed to other units.

Emissions Data

Emission rate calculations for the sources listed below are provided at the end of this section.

FIN	EPN	Source Name
39BA3901	JJ-4	39BA3901 CCR Hot Oil Heater
39	F-39	NHT/CCR Fugitives

The CCR Hot Oil Heater fires refinery fuel gas supplied by the CCR refinery fuel gas system. For the CCR Hot Oil Heater, CO_2 emission rates are estimated using the CO_2 emission factor derived from Equation C-5 in 40 C.F.R. Part 98, Subpart C and actual fuel gas carbon content, molecular weight, and higher heating value data for the CCR refinery fuel gas system. CH_4 and N_2O emission rates are estimated using Equation C-8b and the emission factors for “Petroleum” in Table C-2 in 40 C.F.R. Part 98, Subpart C and converting from metric tons to short tons.

Calculations are provided to estimate GHG emissions from just the new equipment piping components for PSD applicability purposes. CH_4 emission rates from the new equipment piping components are estimated based on the VOC emission rate and the estimated weight percent methane. The VOC emission rate is estimated based on the number of each type of component and the emission factors from the TCEQ’s Fugitive Guidance Document dated October 2000 (Appendix A).

CO_2e emissions are defined as the sum of the mass emissions of each individual greenhouse gas (GHG) adjusted for its global warming potential (GWP). CO_2e emission rates for each GHG are estimated by multiplying the emission rates for each GHG by its GWP value provided in Table A-1 of 40 C.F.R. Part 98, Subpart A.

Greenhouse Gas Emission Rate Calculations

INPUT DATA

Combustion Unit Description:	39BA3901 CCR Hot Oil Heater
Facility Identification Number (FIN):	39BA3901
Emission Point Number (EPN):	JJ-4

COMBUSTION UNIT DATA

Fuel Gas Firing Capacity, HHV:	123.6	MMBtu/hr, HHV
Operating Hours	8760	hrs/yr

EMISSION FACTORS

Pollutant	Emission Factor (kg/MMBtu) *	Emission Factor (lb/MMBtu) *	Global Warming Potentials **
Carbon Dioxide (CO_2)	N/A	116.17	1
Methane (CH_4)	0.003	0.0066	25
Nitrous Oxide (N_2O)	0.0006	0.00132	298

* The heater fires refinery fuel gas. The CO2 emission factor is derived from Equation C-5 in 40 C.F.R. Part 98, Subpart C and actual fuel gas data for the CCR fuel gas system. The CH_4 and N_2O factors are from 40 CFR 98, Table C-2 for petroleum.

** Global warming potentials are from Table A-1 in 40 CFR 98, Subpart A.

EMISSION RATES

Pollutant	GHG Annual Emissions (tons/yr)	CO_2e Annual Emissions (tons/yr)
Carbon Dioxide (CO_2)	62890	62890
Methane (CH_4)	3.58	89.51
Nitrous Oxide (N_2O)	0.72	213.40
Total	62894	63193

Emission rates are calculated using equations C-5 and C-8b and converting from metric tons/yr.

Equation C-5 from 40 CFR 98, Subpart C

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 \qquad \text{(Eq. C-5)}$$

CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose.
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6. Use 849.5 scf per kg mole if you select 68 °F as standard temperature and 836.6 scf per kg mole if you select 60 °F as standard temperature.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

Equation C-8b from 40 CFR 98, Subpart C
CH_4 or N_2O (metric tons/yr) = 0.001 x Gas x EF
where
Gas = Annual natural gas usage (MMBtu)
EF = Fuel specific default CH_4 or N_2O emission factor for natural gas from Table C-2 (kg/MMBtu)

1 metric ton = 1.1023 short tons

Greenhouse Gas Fugitive Emission Rate Estimates
CCR-NHT
New Components

FIN:	39
EPN:	F-39
Operating schedule (hr/yr):	8760

Fugitive Emission Calculations:

Emission Source	Source Count	Uncontrolled Emission Factor [1] (lb/hr-source)	Control Factor [2]	Hourly Emissions (lb/hr)
Valves - Gas	63	0.059	97%	0.112
Valves - Gas (DM)	0	0.059	75%	0
Valves - Light Liquid	7	0.024	97%	0.00504
Valves - Light Liquid (DM)	0	0.024	75%	0
Valves - Heavy Liquid	0	0.00051	0%	0
Pumps - Light Liquid	0	0.251	93%	0
Pumps - Light Liquid (sealess)	2	0.251	100%	0
Pumps - Heavy Liquid	0	0.046	0%	0
Flanges - Gas	99	0.00055	75%	0.0136
Flanges - Light Liquid	11	0.00055	75%	0.00151
Flanges - Heavy Liquid	0	0.00055	30%	0
Compressors	0	1.399	95%	0
Pressure Relief Valves [3]	5	0.35	100%	0
Sampling Connections	0	0.033	97%	0
Total Hourly Emissions				**0.132**
Total Annual Emissions				**0.578**

Sample Calculations:

Valve Emissions = (63 valves)(0.059 lb/hr-source)(1 - 0.97)
= 0.112 lb/hr

Annual Emissions = (0.132 lb/hr)(8760 hr/yr)(1 ton/2000 lb)
= 0.578 tons/yr

Emissions Speciation

Contaminant	Contaminant Code	Maximum Speciated Composition by Component (Wt %)	Hourly Speciated Emission Rates (lb/hr)	Annual Speciated Emission Rates (tons/yr)
Methane	60000	10.00%	0.013	0.058

NOTES:

(1) The emission factors used are refinery factors from the TCEQ Fugitive Guidance Document dated October 2000.
(2) The control factors are for a 28VHP program from the TCEQ Fugitive Guidance Document dated October 2000. Difficult to monitor (DM) sources are monitored annually. Light liquid pumps and compressors are monitored at a 500 ppmv leak definition instead of 2000 ppmv, which is equivalent to the 28MID program. Heavy liquid flanges have a 30% control efficiency applied as a result of the weekly AVO monitoring.
(3) PRVs are routed to a flare or are equipped with a rupture disk upstream or downstream with a pressure gauge.

EMISSION RATES

Pollutant	GHG Annual Emissions (tons/yr)	Global Warming Potentials *	CO_2e Annual Emissions (tons/yr)
Methane (CH_4)	0.06	25	1.45
Total	0.06		1.45

DHT UNIT (PREVIOUSLY GOHT UNIT)

The Gas Oil Hydrotreater (GOHT) Unit is an existing unit at the West Refinery. FHR is converting the existing GOHT Unit to the Distillate Hydrotreater (DHT) Unit. The project will require installation of new equipment piping components. There are no proposed physical changes or changes in the method of operation for the DHT Charge Heater (37BA1) and the DHT Stripper Reboiler (37BA2). However, as a result of this project, the reboiler will experience an increase in actual emissions. It is not clear that the DHT Stripper Reboiler will realize an increase as a result of debottlenecking or increased utilization. As a result, an actual to potential analysis is conservatively used for this emissions unit to assess PSD applicability. Calculations are provided for the DHT stripper reboiler at its currently authorized maximum duty of 70.9 MMBtu/hr (HHV) to represent the potential to emit of GHG emissions.

<u>General Process Description</u>

The DHT Unit removes sulfur from a mixed distillate feed consisting of naphtha, gas oil, light cycle oil, and diesel to produce a diesel fuel product meeting the EPA requirements for sulfur content.

<u>Emissions Data</u>

Emission rate calculations for the sources listed below are provided at the end of this section.

FIN	EPN	Source Name
37BA2	KK-3	37BA2 DHT Stripper Reboiler
37	F-37	DHT Fugitives

Calculations are provided for the DHT Stripper reboiler to estimate GHG emissions at its currently authorized maximum duty of 70.9 MMBtu/hr (HHV). The DHT Stripper Reboiler fires refinery fuel gas supplied by the Mid Plant refinery fuel gas system. CO_2 emission rates are estimated using the CO_2 emission factor derived from Equation C-5 in 40 C.F.R. Part 98, Subpart C and actual fuel gas carbon content, molecular weight, and higher heating value data for the Mid Plant refinery fuel gas system. CH_4 and N_2O are estimated using Equation C-8b and the emission factors for "Petroleum" in Table C-2 in 40 C.F.R. Part 98, Subpart C and converting from metric tons to short tons.

Calculations are provided to estimate GHG emissions from just the new equipment piping components for PSD applicability purposes. CH_4 emission rates from the new equipment piping components are estimated based on the VOC emission rate and the estimated weight percent methane. The VOC emission rate is estimated based on the number of each type of component and the emission factors from the TCEQ's Fugitive Guidance Document dated October 2000 (Appendix A).

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its GWP. CO_2e emission rates for each GHG are estimated by multiplying the emission rates for each GHG by its GWP value provided in Table A-1 of 40 C.F.R. Part 98, Subpart A.

Greenhouse Gas Emission Rate Calculations

INPUT DATA

Combustion Unit Description:	37BA2 DHT Stripper Reboiler (Potential to Emit)
Facility Identification Number (FIN):	37BA2
Emission Point Number (EPN):	KK-3

COMBUSTION UNIT DATA

Fuel Gas Firing Capacity, HHV:	70.9	MMBtu/hr, HHV
Operating Hours	8760	hrs/yr

EMISSION FACTORS

Pollutant	Emission Factor (kg/MMBtu) *	Emission Factor (lb/MMBtu)	Global Warming Potentials **
Carbon Dioxide (CO_2)	N/A	120.05	1
Methane (CH_4)	0.003	0.0066	25
Nitrous Oxide (N_2O)	0.0006	0.00132	298

* The heater fires refinery fuel gas. The CO2 emission factor is derived from Equation C-5 in 40 C.F.R. Part 98, Subpart C and actual fuel gas data for the Mid Plant fuel gas system. The CH_4 and N_2O factors are from 40 CFR 98, Table C-2 for petroleum.

** Global warming potentials are from Table A-1 in 40 CFR 98, Subpart A.

EMISSION RATES

Pollutant	GHG Annual Emissions (tons/yr)	CO_2e Annual Emissions (tons/yr)
Carbon Dioxide (CO_2)	37280	37280
Methane (CH_4)	2.05	51.35
Nitrous Oxide (N_2O)	0.41	122.41
Total	37282	37454

Emission rates are calculated using equations C-5 and C-8b and converting from metric tons/yr.

Equation C-5 from 40 CFR 98, Subpart C

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 \qquad \text{(Eq. C-5)}$$

CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose.
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6. Use 849.5 scf per kg mole if you select 68 °F as standard temperature and 836.6 scf per kg mole if you select 60 °F as standard temperature.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

Equation C-8b from 40 CFR 98, Subpart C

CH_4 or N_2O (metric tons/yr) = 0.001 x Gas x EF

where

Gas = Annual natural gas usage (MMBtu)

EF = Fuel specific default CH_4 or N_2O emission factor for natural gas from Table C-2 (kg/MMBtu)

1 metric ton = 1.1023 short tons

Greenhouse Gas Fugitive Emission Rate Estimates
DHT (Previously GOHT)
New Components

FIN:	37
EPN:	F-37
Operating schedule (hr/yr):	8760

Fugitive Emission Calculations:

Emission Source	Source Count	Uncontrolled Emission Factor [1] (lb/hr-source)	Control Factor [2]	Hourly Emissions (lb/hr)
Valves - Gas	29	0.059	97%	0.0513
Valves - Gas (DM)	1	0.059	75%	0.0148
Valves - Light Liquid	20	0.024	97%	0.0144
Valves - Light Liquid (DM)	1	0.024	75%	0.006
Valves - Heavy Liquid	0	0.00051	0%	0
Pumps - Light Liquid	1	0.251	85%	0.0377
Pumps - Light Liquid	0	0.251	100%	0
Pumps - Heavy Liquid	0	0.046	0%	0
Flanges - Gas	74	0.00055	75%	0.0102
Flanges - Light Liquid	49	0.00055	75%	0.00674
Flanges - Heavy Liquid	0	0.00055	30%	0
Compressors	1	1.399	85%	0.21
Pressure Relief Valves [3]	1	0.35	100%	0
Sampling Connections	0	0.033	97%	0
Total Hourly Emissions				**0.351**
Total Annual Emissions				**1.54**

Sample Calculations:

Valve Emissions = (29 valves)(0.059 lb/hr-source)(1 - 0.97)
= 0.0513 lb/hr

Annual Emissions = (0.351 lb/hr)(8760 hr/yr)(1 ton/2000 lb)
= 1.54 tons/yr

Emissions Speciation

Contaminant	Contaminant Code	Maximum Speciated Composition by Component (Wt %)	Hourly Speciated Emission Rates (lb/hr)	Annual Speciated Emission Rates (tons/yr)
Methane	60000	10.00%	0.035	0.154

NOTES:

(1) The emission factors used are refinery factors from the TCEQ Fugitive Guidance Document dated October 2000.
(2) The control factors are for a 28VHP program from the TCEQ Fugitive Guidance Document dated October 2000. Heavy liquid flanges have a 30% control efficiency applied as a result of the weekly AVO monitoring. Difficult to monitor (DM) sources are monitored annually.
(3) PRVs are routed to a flare or are equipped with a rupture disk upstream or downstream with a pressure gauge.

EMISSION RATES

Pollutant	GHG Annual Emissions (tons/yr)	Global Warming Potentials *	CO_2e Annual Emissions (tons/yr)
Methane (CH_4)	0.15	25	3.84
Total	0.15		3.84

MID CRUDE UNIT

The Mid Crude Unit is an existing unit at the West Refinery. FHR is proposing to install new equipment piping components as a result of this project.

General Process Description

The Mid Crude separates crude oil into fractions by distillation and steam stripping using the differences in boiling ranges to effect the separation. Distillate fractions produced by the crude unit include light ends, naphtha, jet fuel, diesel fuel or No. 2 fuel oil, gas oil, and residual oil. Pressures range from atmospheric to near full vacuum.

Emissions Data

Emission rate calculations for the sources listed below are provided at the end of this section.

FIN	EPN	Source Name
42	F-42	Mid Crude Fugitives

Calculations are provided to estimate GHG emissions from just the new equipment piping components for PSD applicability purposes. CH_4 emission rates from the new equipment piping components are estimated based on the VOC emission rate and the estimated weight percent methane. The VOC emission rate is estimated based on the number of each type of component and the emission factors from the TCEQ's Fugitive Guidance Document dated October 2000 (Appendix A).

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its GWP. CO_2e emission rates for each GHG are estimated by multiplying the emission rates for each GHG by its GWP value provided in Table A-1 of 40 C.F.R. Part 98, Subpart A.

Greenhouse Gas Fugitive Emission Rate Estimates
Mid Crude (No. 4 Crude)
New Components

FIN:	42
EPN:	F-42
Operating schedule (hr/yr):	8760

Fugitive Emission Calculations:

Emission Source	Source Count	Uncontrolled Emission Factor [1] (lb/hr-source)	Control Factor [2]	Hourly Emissions (lb/hr)
Valves - Gas	292	0.059	97%	0.517
Valves - Gas (DM)	0	0.059	75%	0
Valves - Light Liquid	747	0.024	97%	0.538
Valves - Light Liquid (DM)	4	0.024	75%	0.024
Valves - Heavy Liquid	180	0.00051	0%	0.0918
Pumps - Light Liquid	7	0.251	93%	0.123
Pumps - Light Liquid (sealess)	1	0.251	100%	0
Pumps - Heavy Liquid	4	0.046	0%	0.184
Flanges - Gas	731	0.00055	75%	0.101
Flanges - Light Liquid	1,878	0.00055	75%	0.258
Flanges - Heavy Liquid	450	0.00055	30%	0.173
Compressors	1	1.399	95%	0.07
Pressure Relief Valves [3]	5	0.35	100%	0
Sampling Connections	0	0.033	97%	0
Total Hourly Emissions				**2.08**
Total Annual Emissions				**9.11**

Sample Calculations:

Valve Emissions = (292 valves)(0.059 lb/hr-source)(1 - 0.97)
= 0.517 lb/hr

Annual Emissions = (2.08 lb/hr)(8760 hr/yr)(1 ton/2000 lb)
= 9.11 tons/yr

Emissions Speciation

Contaminant	Contaminant Code	Maximum Speciated Composition by Component (Wt %)	Hourly Speciated Emission Rates (lb/hr)	Annual Speciated Emission Rates (tons/yr)
Methane	60000	10.00%	0.208	0.911

NOTES:

(1) The emission factors used are refinery factors from the TCEQ Fugitive Guidance Document dated October 2000.
(2) The control factors are for a 28VHP program from the TCEQ Fugitive Guidance Document dated October 2000. Difficult to monitor (DM) sources are monitored annually. Light liquid pumps and compressors are monitored at a 500 ppmv leak definition instead of 2000 ppmv, which is equivalent to the 28MID program. Heavy liquid flanges have a 30% control efficiency applied as a result of the weekly AVO monitoring.
(3) PRVs are routed to a flare or are equipped with a rupture disk upstream or downstream with a pressure gauge.

EMISSION RATES

Pollutant	GHG Annual Emissions (tons/yr)	Global Warming Potentials *	CO_2e Annual Emissions (tons/yr)
Methane (CH_4)	0.91	25	22.78
Total	0.91		22.78

SATURATES GAS NO. 3

FHR is proposing to construct a new Saturates Gas (Sat Gas) No. 3 Unit. The new unit will include the Sat Gas No. 3 Hot Oil Heater and new equipment piping components. The hot oil heater will have a maximum fired duty of 450 MMBtu/hr (HHV).

General Process Description

The Saturates Gas Plant No. 3 will operate to recover propane and heavier hydrocarbons from a number of refinery streams and to fractionate the recovered hydrocarbons into various product streams. Hydrocarbon recovery will be via absorption by a combination of internally produced "lean oil" for propane recovery and by externally fed sponge oil(s) for heavy-ends recovery.

The unit will produce a fuel gas which is lean in C_3+ hydrocarbons, a propane liquid product, an isobutene product, a normal butane product, a C_5+ liquid product, a rich sponge oil return liquid and a sour water waste stream. Each of these streams will be sent out of the unit for further treating, sales or as feedstocks.

Emissions Data

Emission rate calculations for the sources listed below are provided at the end of this section.

FIN	EPN	Source Name
SATGASHTR	SATGASHTR	Sat Gas No. 3 Hot Oil Heater
F-SATGAS3	F-SATGAS3	Sat Gas No. 3 Fugitives

The heater will fire mainly natural gas. Accordingly, for the Sat Gas No. 3 Hot Oil Heater, CO_2 emission rates are estimated using the CO_2 emission factor derived from Equation C-5 in 40 C.F.R. Part 98, Subpart C and actual fuel gas carbon content, molecular weight, and higher heating value data for the purchased natural gas system. CH_4 and N_2O are estimated using Equation C-8b and the emission factors in Table C-2 in 40 C.F.R. Part 98, Subpart C and converting from metric tons to short tons. The heater will also burn an off-gas stream from the Merox Treating Unit. The flow rate of this stream will be so small compared to the natural gas stream that it is not expected to significantly impact the GHG emissions from the heater. Therefore, emission rates are estimated using the emission factors for natural gas.

Calculations are provided to estimate GHG emissions from the new equipment piping components for PSD applicability purposes. CH_4 emission rates from the new equipment piping components are estimated based on the VOC emission rate and the estimated weight percent methane. The VOC emission rate is estimated based on the number of each type of component and the emission factors from the TCEQ's Fugitive Guidance Document dated October 2000 (Appendix A).

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its GWP. CO_2e emission rates for each GHG are estimated by multiplying the emission rates for each GHG by its GWP value provided in Table A-1 of 40 C.F.R. Part 98, Subpart A.

Greenhouse Gas Emission Rate Calculations

INPUT DATA

Combustion Unit Description:	Sat Gas No. 3 Hot Oil Heater
Facility Identification Number (FIN):	SATGASHTR
Emission Point Number (EPN):	SATGASHTR

COMBUSTION UNIT DATA

Fuel Gas Firing Capacity, HHV:	450	MMBtu/hr, HHV
Operating Hours	8760	hrs/yr

EMISSION FACTORS

Pollutant	Emission Factor (kg/MMBtu) *	Emission Factor (lb/MMBtu) *	Global Warming Potentials **
Carbon Dioxide (CO_2)	N/A	119.74	1
Methane (CH_4)	0.001	0.0022	25
Nitrous Oxide (N_2O)	0.0001	0.00022	298

* The heater will fire natural gas. The CO2 emission factor is derived from Equation C-5 in 40 C.F.R. Part 98, Subpart C and actual fuel gas data for the purchased natural gas system. The CH_4 and N_2O factors are from 40 CFR 98, Table C-2 for natural gas.

** Global warming potentials are from Table A-1 in 40 CFR 98, Subpart A.

EMISSION RATES

Pollutant	GHG Annual Emissions (tons/yr)	CO_2e Annual Emissions (tons/yr)
Carbon Dioxide (CO_2)	236004	236004
Methane (CH_4)	4.35	108.63
Nitrous Oxide (N_2O)	0.43	129.49
Total	236009	236242

Emission rates are calculated using equations C-5 and C-8b and converting from metric tons/yr.

Equation C-5 from 40 CFR 98, Subpart C

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 \qquad \text{(Eq. C-5)}$$

CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose.
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6. Use 849.5 scf per kg mole if you select 68 °F as standard temperature and 836.6 scf per kg mole if you select 60 °F as standard temperature.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

Equation C-8b from 40 CFR 98, Subpart C
CH_4 or N_2O (metric tons/yr) = 0.001 x Gas x EF
where
Gas = Annual natural gas usage (MMBtu)
EF = Fuel specific default CH_4 or N_2O emission factor for natural gas from Table C-2 (kg/MMBtu)

1 metric ton = 1.1023 short tons

Greenhouse Gas Fugitive Emission Rate Estimates
Sat Gas No. 3 Fugitives
New Components

FIN:	F-SATGAS3
EPN:	F-SATGAS3
Operating schedule (hr/yr):	8760

Fugitive Emission Calculations:

Emission Source	Source Count	Uncontrolled Emission Factor [1] (lb/hr-source)	Control Factor [2]	Hourly Emissions (lb/hr)
Valves - Gas	0	0.059	97%	0
Valves - Gas (DM)	0	0.059	75%	0
Valves - Light Liquid	2,535	0.024	97%	1.83
Valves - Light Liquid (DM)	6	0.024	75%	0.036
Valves - Heavy Liquid	0	0.00051	0%	0
Pumps - Light Liquid	0	0.251	93%	0
Pumps - Light Liquid (sealess)	29	0.251	100%	0
Pumps - Heavy Liquid	0	0.046	0%	0
Flanges - Gas	1,555	0.00055	75%	0.214
Flanges - Light Liquid	6,253	0.00055	75%	0.86
Flanges - Heavy Liquid	0	0.00055	30%	0
Compressors	0	1.399	95%	0
Pressure Relief Valves [3]	16	0.35	100%	0
Sampling Connections	0	0.033	97%	0
Total Hourly Emissions				**2.94**
Total Annual Emissions				**12.9**

Sample Calculations:

Valve Emissions = (0 valves)(0.059 lb/hr-source)(1 - 0.97)
= 0 lb/hr

Annual Emissions = (2.94 lb/hr)(8760 hr/yr)(1 ton/2000 lb)
= 12.9 tons/yr

Emissions Speciation

Contaminant	Contaminant Code	Maximum Speciated Composition by Component (Wt %)	Hourly Speciated Emission Rates (lb/hr)	Annual Speciated Emission Rates (tons/yr)
Methane	60000	50.00%	1.470	6.439

NOTES:

(1) The emission factors used are refinery factors from the TCEQ Fugitive Guidance Document dated October 2000.
(2) The control factors are for a 28VHP program from the TCEQ Fugitive Guidance Document dated October 2000. Difficult to monitor (DM) sources are monitored annually. Light liquid pumps and compressors are monitored at a 500 ppmv leak definition instead of 2000 ppmv, which is equivalent to the 28MID program. Heavy liquid flanges have a 30% control efficiency applied as a result of the weekly AVO monitoring.
(3) PRVs are routed to a flare or are equipped with a rupture disk upstream or downstream with a pressure gauge.

EMISSION RATES

Pollutant	GHG Annual Emissions (tons/yr)	Global Warming Potentials *	CO_2e Annual Emissions (tons/yr)
Methane (CH_4)	6.44	25	160.97
Total	6.44		160.97

* Global warming potentials are from Table A-1 in 40 CFR 98, Subpart A.

UDEX UNIT

The Universal Dow Extraction (UDEX) Unit is an existing unit at the West Refinery. The project will require installation of new equipment piping components.

General Process Description

The UDEX Unit removes aromatics from a feed stream composed of toluene, mixed xylenes, benzene and heavy aromatics. The aromatics are removed from the feed stream using glycol and liquid-liquid extraction and exit the unit as extract product which is further separated in downstream fractionation columns. The non-aromatics along with some aromatics end up in the raffinate product stream.

Emissions Data

Emission rate calculations for the sources listed below are provided at the end of this section.

FIN	EPN	Source Name
14-UDEX	F-14-UDEX	Udex Fugitives

Calculations are provided to estimate GHG emissions from just the new equipment piping components for PSD applicability purposes. CH_4 emission rates from the new equipment piping components are estimated based on the VOC emission rate and the estimated weight percent methane. The VOC emission rate is estimated based on the number of each type of component and the emission factors from the TCEQ's Fugitive Guidance Document dated October 2000 (Appendix A).

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its GWP. CO_2e emission rates for each GHG are estimated by multiplying the emission rates for each GHG by its GWP value provided in Table A-1 of 40 C.F.R. Part 98, Subpart A.

Greenhouse Gas Fugitive Emission Rate Estimates
UDEX
New Components

FIN:	14-UDEX
EPN:	F-14-UDEX
Operating schedule (hr/yr):	8760

Fugitive Emission Calculations:

Emission Source	Source Count	Uncontrolled Emission Factor [1] (lb/hr-source)	Control Factor [2]	Hourly Emissions (lb/hr)
Valves - Gas	0	0.0089	97%	0
Valves - Gas (DM)	0	0.0089	75%	0
Valves - Light Liquid	60	0.0035	97%	0.0063
Valves - Light Liquid (DM)	0	0.0035	75%	0
Valves - Heavy Liquid	0	0.0007	0%	0
Pumps - Light Liquid	0	0.0386	85%	0
Pumps - Light Liquid	2	0.0386	100%	0
Pumps - Heavy Liquid	0	0.0161	0%	0.00177
Flanges - Gas	0	0.0029	75%	0
Flanges - Light Liquid	80	0.0005	75%	0.01
Flanges - Heavy Liquid	0	0.00007	30%	0
Compressors	0	0.5027	85%	0
Pressure Relief Valves [3]	0	0.23	100%	0
Sampling Connections	0	0.033	97%	0
Total Hourly Emissions				**0.0181**
Total Annual Emissions				**0.0793**

Sample Calculations:

Valve Emissions = (0 valves)(0.0089 lb/hr-source)(1 - 0.97)
= 0 lb/hr

Annual Emissions = (0.0181 lb/hr)(8760 hr/yr)(1 ton/2000 lb)
= 0.0793 tons/yr

Emissions Speciation

Contaminant	Contaminant Code	Maximum Speciated Composition by Component (Wt %)	Hourly Speciated Emission Rates (lb/hr)	Annual Speciated Emission Rates (tons/yr)
Methane	60000	10.00%	0.002	0.008

NOTES:

(1) The emission factors used are SOCMI w/out ethylene factors from the TCEQ Fugitive Guidance Document dated October 2000.
(2) The control factors are for a 28VHP program from the TCEQ Fugitive Guidance Document dated October 2000. Heavy liquid flanges have a 30% control efficiency applied as a result of the weekly AVO monitoring. Difficult to monitor (DM) sources are monitored annually.
(3) PRVs are routed to a flare or are equipped with a rupture disk upstream or downstream with a pressure gauge.

EMISSION RATES

Pollutant	GHG Annual Emissions (tons/yr)	Global Warming Potentials *	CO_2e Annual Emissions (tons/yr)
Methane (CH_4)	0.01	25	0.20
Total	0.01		0.20

* Global warming potentials are from Table A-1 in 40 CFR 98, Subpart A.

WEST CRUDE

The West Crude Unit is an existing unit at the West Refinery. FHR is proposing process changes in the West Crude Unit which require installation of new equipment piping components.

General Process Description

The West Crude separates crude oil into fractions by distillation and steam stripping using the differences in boiling ranges to affect the separation. Distillate fractions produced by the crude unit include light ends, naphtha, jet fuel, diesel fuel or No. 2 fuel oil, gas oil, and residual oil. Pressures range from atmospheric to near full vacuum.

Emissions Data

Emission rate calculations for the sources listed below are provided at the end of this section:

FIN	EPN	Source Name
40	F-40	West Crude Fugitives

Calculations are provided to estimate GHG emissions from just the new equipment piping components for PSD applicability purposes. CH_4 emission rates from the new equipment piping components are estimated based on the VOC emission rate and the estimated weight percent methane. The VOC emission rate is estimated based on the number of each type of component and the emission factors from the TCEQ's Fugitive Guidance Document dated October 2000 (Appendix A).

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its GWP. CO_2e emission rates for each GHG are estimated by multiplying the emission rates for each GHG by its GWP value provided in Table A-1 of 40 C.F.R. Part 98, Subpart A.

Greenhouse Gas Fugitive Emission Rate Estimates
West Crude
New Components

FIN:	40
EPN:	F-40
Operating schedule (hr/yr):	8760

Fugitive Emission Calculations:

Emission Source	Source Count	Uncontrolled Emission Factor [1] (lb/hr-source)	Control Factor [2]	Hourly Emissions (lb/hr)
Valves - Gas	120	0.059	97%	0.212
Valves - Gas (DM)	3	0.059	75%	0.0443
Valves - Light Liquid	268	0.024	97%	0.193
Valves - Light Liquid (DM)	3	0.024	75%	0.018
Valves - Heavy Liquid	0	0.00051	0%	0
Pumps - Light Liquid	1	0.251	85%	0.0377
Pumps - Light Liquid (Sealess)	4	0.251	100%	0
Pumps - Heavy Liquid	2	0.046	0%	0.092
Flanges - Gas	308	0.00055	75%	0.0424
Flanges - Light Liquid	678	0.00055	75%	0.0932
Flanges - Heavy Liquid	0	0.00055	30%	0
Compressors	0	1.399	85%	0
Pressure Relief Valves [3]	2	0.35	100%	0
Sampling Connections	0	0.033	97%	0
Total Hourly Emissions				**0.733**
Total Annual Emissions				**3.21**

Sample Calculations:

Valve Emissions = (120 valves)(0.059 lb/hr-source)(1 - 0.97)
= 0.212 lb/hr

Annual Emissions = (0.733 lb/hr)(8760 hr/yr)(1 ton/2000 lb)
= 3.21 tons/yr

Emissions Speciation

Contaminant	Contaminant Code	Maximum Speciated Composition by Component (Wt %)	Hourly Speciated Emission Rates (lb/hr)	Annual Speciated Emission Rates (tons/yr)
Methane	60000	10.00%	0.073	0.321

NOTES:

(1) The emission factors used are refinery factors from the TCEQ Fugitive Guidance Document dated October 2000.
(2) The control factors are for a 28VHP program from the TCEQ Fugitive Guidance Document dated October 2000. Heavy liquid flanges have a 30% control efficiency applied as a result of the weekly AVO monitoring. Difficult to monitor (DM) sources are monitored annually.
(3) PRVs are routed to a flare or are equipped with a rupture disk upstream or downstream with a pressure gauge.

EMISSION RATES

Pollutant	GHG Annual	Global Warming	CO_2e Annual
Methane (CH_4)	0.32	25	8.03
Total	0.32		8.03

UTILITIES

The utilities area at the West Refinery consists of 6 existing boilers that supply steam to the refinery. There are no proposed physical changes or changes in method of operation to any of these boilers. However, as a result of this project, there will be an increase in steam demand that will be supplied by one or more of the following utility area boilers: the Mid Crude Boiler (43BF1), Boiler No. 7 (06BF657), Boiler No. 8 (06BF658), and Boiler No. 9 (06BF659). Accordingly, because each of these four boilers is potentially affected by the project, the increase in actual boiler emissions resulting from the increased steam demand is included in the PSD applicability assessment.

The incremental increase in actual emissions resulting from the project increase in steam demand is calculated based on an incremental increase in boiler duty of 96 MMBtu/hr (HHV). Because any of the four boilers could potentially supply the additional steam and, therefore, see an increase in utilization as a result of the project, the four boilers have been grouped together into a single emission source called “Various Boilers”.

General Process Description

The boilers provide steam to various processes within the refinery.

Emissions Data

Emission rate calculations for the sources listed below are provided at the end of this section.

FIN	EPN	Source Name
Various Boilers	Various Boilers	Various boilers seeing increased utilization.

Calculations are provided to estimate GHG emissions from the boilers for the incremental increase in duty. The Mid Crude Boiler fires fuel gas from the Mid Plant refinery fuel gas system, and Boilers No. 7, No. 8, and No. 9 fire fuel gas from the 90# refinery fuel gas system. CO_2 emission rates for the incremental increase in duty are estimated using the CO_2 emission factor derived from Equation C-5 in 40 C.F.R. Part 98, Subpart C and actual fuel gas carbon content, molecular weight, and higher heating value data for the Mid Plant refinery fuel gas system because the CO_2 emission factor for the Mid Plant refinery fuel gas system is higher than the factor for the 90# refinery fuel gas system. CH_4 and N_2O are estimated using Equation C-8b and the emission factors for “Petroleum” in Table C-2 in 40 C.F.R. Part 98, Subpart C and converting from metric tons to short tons.

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its GWP. CO_2e emission rates for each GHG are estimated by multiplying the emission rates for each GHG by its GWP value provided in Table A-1 of 40 C.F.R. Part 98, Subpart A.

Greenhouse Gas Emission Rate Calculations

INPUT DATA

Combustion Unit Description:	Boilers (Incremental Increase)
Facility Identification Number (FIN):	Various Boilers
Emission Point Number (EPN):	Various Boilers

COMBUSTION UNIT DATA

Fuel Gas Firing Capacity, HHV:	96	MMBtu/hr, HHV
Operating Hours	8760	hrs/yr

EMISSION FACTORS

Pollutant	Emission Factor (kg/MMBtu) *	Emission Factor (lb/MMBtu) *	Global Warming Potentials **
Carbon Dioxide (CO_2)	N/A	120.05	1
Methane (CH_4)	0.003	0.0066	25
Nitrous Oxide (N_2O)	0.0006	0.00132	298

* The boilers fire refinery fuel gas. The CO2 emission factor is derived from Equation C-5 in 40 C.F.R. Part 98, Subpart C and actual fuel gas data for the Mid Plant fuel gas system. The CH_4 and N_2O factors are from 40 CFR 98, Table C-2 for petroleum.

** Global warming potentials are from Table A-1 in 40 CFR 98, Subpart A.

EMISSION RATES

Pollutant	GHG Annual Emissions (tons/yr)	CO_2e Annual Emissions (tons/yr)
Carbon Dioxide (CO_2)	50478	50478
Methane (CH_4)	2.78	69.52
Nitrous Oxide (N_2O)	0.56	165.74
Total	50481	50713

Emission rates are calculated using equations C-5 and C-8b and converting from metric tons/yr.

Equation C-5 from 40 CFR 98, Subpart C

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 \qquad \text{(Eq. C-5)}$$

CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i). Fuel billing meters may be used for this purpose.
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6. Use 849.5 scf per kg mole if you select 68 °F as standard temperature and 836.6 scf per kg mole if you select 60 °F as standard temperature.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion factor from kg to metric tons.

Equation C-8b from 40 CFR 98, Subpart C

CH_4 or N_2O (metric tons/yr) = 0.001 x Gas x EF

where

Gas = Annual natural gas usage (MMBtu)
EF = Fuel specific default CH_4 or N_2O emission factor for natural gas from Table C-2 (kg/MMBtu)

1 metric ton = 1.1023 short tons

WASTEWATER TREATMENT

There are no proposed physical changes or changes in the method of operation for the API Separator Flare (EPN V-8). However, as a result of this project, the flare will experience an increase in actual emissions. Because the flare is an affected emission unit downstream of the project, these changes in actual emissions are included in the PSD applicability assessment. The incremental increase in actual emissions as a result of the project is calculated based on an incremental increase of 4.73 MMscf/yr of vent gas routed to the API Separator Flare.

General Process Description

The wastewater streams affected by this project enter the Monroe API Separator where slop oil and sludge are removed and sent to storage. Emissions from the Monroe API Separator are controlled by the API Separator Flare (EPN V-8). FHR operates a caustic scrubber on the Monroe API Separator to reduce sulfur in the waste gas stream routed to the API Separator Flare. The API Separator Flare meets the requirements of 40 C.F.R. 60.18 and provides a minimum destruction efficiency of 98% based on TCEQ guidance.

Emissions Data

Emission rate calculations for the sources listed below are provided at the end of this section:

FIN	EPN	Source Name
45BD3	V8	API Separator Flare

For the API Separator Flare (EPN V-8), CO_2, CH_4, and N_2O emission rates are estimated using Equations Y-3, Y-4, and Y-5, respectively, in 40 C.F.R. Part 98, Subpart Y and converting from metric tons to short tons.

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its GWP. CO_2e emission rates for each GHG are estimated by multiplying the emission rates for each GHG by its GWP value provided in Table A-1 of 40 C.F.R. Part 98, Subpart A.

Greenhouse Gas Emission Rate Calculations

INPUT DATA

Combustion Unit Description:	API Separator Flare (Incremental Increase)
Facility Identification Number (FIN):	45BD3
Emission Point Number (EPN):	V-8

FLARE DATA

Volume of Flare Gas Combusted:	4.73	MMscf/yr
Higher Heating Value of Flare Gas:	1,088	Btu/scf

GHG EMISSION FACTORS

Pollutant	Emission Factor (kg/MMBtu) *	Global Warming Potentials **
Carbon Dioxide (CO_2)	60	1
Methane (CH_4)	0.003	25
Nitrous Oxide (N_2O)	0.0006	298

* CO_2 emission factors are from 40 CFR 98, Subpart Y. CH_4 and N_2O emission factors are from Table C-2 in 40 CFR 98, Subpart C for Petrolem Products.
** Global warming potentials are from Table A-1 in 40 CFR 98, Subpart A.

EMISSION RATES

Pollutant	GHG Annual Emissions (tons/yr)	CO_2-e Annual Emissions (tons/yr)
Carbon Dioxide (CO_2)	333.62	333.62
Methane (CH_4)	1.11	27.75
Nitrous Oxide (N_2O)	0.0037	1.10
Total	334.73	362.47

Emission rates are calculated using equations Y-3, Y-4, and Y-5 from 40 CFR 98, Subpart Y.

Equation Y-3 from 40 CFR 98, Subpart Y
$CO_2 = 0.98 \times 0.001 \times (Flare_{NORM} \times HHV \times E_mF)$
where
$Flare_{NORM}$ = Annual Volume of flare gas combusted during normal operations in MMscf/yr
HHV = Higher Heating Value for fuel gas or flare gas in Btu/scf
E_mF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis)

Equations Y-4 from 40 CFR 98, Subpart Y
$CH_4 = CO_2 \times E_mF_{CH4} / E_mF + CO_2 \times 0.02/0.98 \times 16/44 \times f_{CH4}$
where
CO_2 = Emission rates calculated from Equation Y-3.
E_mF_{CH4} = Default CH_4 emission factor for "Petroleum Products from Table C-2 of Subpart C.
E_mF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis)
f_{CH4} = Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane, default 0.4

$N_2O = CO_2 \times E_mF_{N2O} / E_mF$
where
CO_2 = Emission rates calculated from Equation Y-3.
E_mF_{N2O} = Default N_2O emission factor for "Petroleum Products from Table C-2 of Subpart C.
E_mF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis)

1 metric ton = 1.023 short tons

MARINE LOADING

The Marine Vapor Combustor is an existing source at the West Refinery. FHR is proposing to increase the annual loading rate of naphtha and gasoline at the marine loading terminal. Emissions generated by the naphtha and gasoline marine loading operations are controlled by the Marine Vapor Combustor. Because the proposed change is limited to the increased loading of naphtha and gasoline and not the other products controlled by the Marine Vapor Combustor, calculations are provided estimating GHG emissions for the incremental increase in the loading rate of naphtha and gasoline. These emission rates are used in the PSD applicability assessment.

<u>General Process Description</u>

FHR's West Refinery uses three docks (No. 8, 9, and 10) for marine loading of both ships and barges. When loading toluene, benzene, xylene (all isomers), gasoline and blend stocks, naphthas, cumene, pseudocumene, and penexate, emissions are controlled by a vacuum-assisted loading operation that captures virtually all of the vapors and vents them to the Marine Vapor Combustor (VCS-1). The Marine Vapor Combustor is an enclosed flare with a minimum destruction efficiency of 99.5% for VOC based on stack testing.

<u>Emissions Data</u>

Emission rate calculations for the sources listed below are provided at the end of this section:

FIN	EPN	Source Name
LW-8	VCS-1	Marine Vapor Combustor

For the Marine Vapor Combustor (EPN VCS-1), CO_2, CH_4, and N_2O emission rates are estimated using Equations Y-3, Y-4, and Y-5, respectively, in 40 C.F.R. Part 98, Subpart Y and converting from metric tons to short tons. Because the Marine Vapor Combustor combusts natural gas and other petroleum vapors, the CO_2 emission factor for crude oil from 40 C.F.R. 98, Table C-1 is used rather than the default factor specified in Subpart Y because this is the highest factor from all product vapors being combusted and is the most conservative emission estimate. The CH_4 and N_2O factors are from 40 C.F.R. 98, Table C-2 for petroleum.

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its GWP. CO_2e emission rates for each GHG are estimated by multiplying the emission rates for each GHG by its GWP value provided in Table A-1 of 40 C.F.R. Part 98, Subpart A.

Greenhouse Gas Emission Rate Calculations
Incremental Increase in Emissions (Naphtha and Gasoline Loading Only)

Because FHR is only proposing an incremental increase in the naphtha and gasoline loading rates, incremental emission rates for only naphtha and gasoline loading are calculated for PSD purposes.

INPUT DATA

Combustion Unit Description:	Marine Vapor Combustor (Proposed Increase)
Facility Identification Number (FIN):	VCS-1
Emission Point Number (EPN):	VCS-1

FLARE DATA

Volume of Gas Combusted:	9.49	MMscf/yr
Annual Higher Heating Value of Gas:	4,286	Btu/scf

EMISSION FACTORS

Pollutant	Emission Factor (kg/MMBtu) *	Global Warming Potentials **
Carbon Dioxide (CO_2)	74.49	1
Methane (CH_4)	0.003	25
Nitrous Oxide (N_2O)	0.0006	298

* The control device combusts natural gas and other petroleum vapors. Therefore, the CO_2 emission factor for crude oil from 40 CFR 98, Table C-1 is used rather than the default factor specified in Subpart Y because this is the highest factor from all product vapors being combusted and is the most conservative emission estimate. The CH4 and N2O factors are from 40 CFR 98, Table C-2 for petroleum.

** Global warming potentials are from Table A-1 in 40 CFR 98, Subpart A.

EMISSION RATES

Pollutant	GHG Annual Emissions (tons/yr)	CO_2-e Annual Emissions (tons/yr)
Carbon Dioxide (CO_2)	3271.39	3271.39
Methane (CH_4)	10.8496	271.2411
Nitrous Oxide (N_2O)	0.0290	8.6557
Total	3282.27	3551.28

Emission rates are calculated using equations Y-3, Y-4, and Y-5 from 40 CFR 98, Subpart Y.

Equation Y-3 from 40 CFR 98, Subpart Y

CO_2 (metric tons/yr) = 0.98 x 0.001 x ($Flare_{NORM}$ x HHV x E_mF)

where

$Flare_{NORM}$ = Annual Volume of flare gas combusted during normal operations in MMscf/yr

HHV = Higher Heating Value for fuel gas or flare gas in Btu/scf

E_mF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis) - see note above

Equation Y-4 from 40 CFR 98, Subpart Y

CH_4 (metric tons/yr) = CO_2 x E_mF_{CH4} / E_mF + CO_2 x 0.02/0.98 x 16/44 x f_{CH4}

where

CO_2 = Emission rates calculated from Equation Y-3.

E_mF_{CH4} = Default CH_4 emission factor for petroleum products from Table C-2 of Subpart C.

E_mF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis) - see note above

f_{CH4} = Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane, default 0.4

Equation Y-5 from 40 CFR 98, Subpart Y

N_2O = CO_2 x E_mF_{N2O} / E_mF

where

CO_2 (metric tons/yr) = Emission rates calculated from Equation Y-3.

E_mF_{N2O} = Default N_2O emission factor for petroleum products from Table C-2 of Subpart C.

E_mF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis) - see note above

1 metric ton = 1.1023 short tons

TANK FARM

Storage tanks 08FB137, 08FB142, 08FB147, 40FB1010, and 40FB4011 are existing sources at the West Refinery.[2] There are no proposed physical changes or changes in the method of operation for the storage tanks. However, as a result of this project, the storage tanks will experience an increase in actual emissions as a result of an increase in crude oil throughput. Because the storage tanks are affected emission units downstream of the project, these changes in actual emissions are included in the PSD applicability assessment.

The project will require installation of new equipment piping components.

Emissions Data

Emission rate calculations for the following sources listed below are provided at the end of this section:

FIN	EPN	Source Name
08FB137	FB137	Tank 08FB137
08FB142	FB142	Tank 08FB142
08FB147	FB147	Tank 08FB147
40FB4010	FB4010	Tank 40FB4010
40FB4011	FB4011	Tank 40FB4011
P-VOC	F-TK-VOC	VOC Tank & Loading Fugitives
P-GB	F-GB	Gasoline Blender Fugitives

As required by EPA guidance, GHG emissions are estimated only from storage tanks associated with crude oil storage because of the potential for methane emissions. For storage tanks, CH_4 emission rates are estimated using Equation Y-22 in 40 C.F.R. Part 98, Subpart Y and converting from metric tons to short tons.

Calculations are provided to estimate GHG emissions from just the new equipment piping components for PSD applicability purposes. CH_4 emission rates from the new equipment piping components are estimated based on the VOC emission rate and the weight percent methane. The VOC emission rate is estimated based on the number of each type of component and the emission factors from the TCEQ's Fugitive Guidance Document dated October 2000 (Appendix A).

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its GWP. CO_2e emission rates for each GHG are estimated by multiplying the emission rates for each GHG by its GWP value provided in Table A-1 of 40 C.F.R. Part 98, Subpart A.

2 Tanks 40FB1010 and 40FB1011 are not experiencing a physical change or change in the method of operation. They will be considered a minor modification for the state minor NSR permitting and subject to state BACT review, but are not considered a major modification for federal PSD.

Greenhouse Gas Emission Rate Calculations
Incremental Increase in Emissions (Crude Oil Only)

Tank FIN	Tank EPN	Pollutant	Crude Oil Throughput (MMbbl/yr)	GHG Mass Emissions (tons/yr)	Global Warming Potential	CO_2e (tons/yr)
08FB137	FB137	Methane (CH_4)	12	1.33	25	33.25
08FB142	FB142					
08FB147	FB147					
40FB4010	FB4010					
40FB4011	FB4011					

Emission rates are estimated using Equation Y-22 from 40 CFR 98, Subpart Y

Equation Y-22
CH_4 (metric tons/yr) = 0.1 x Q_{REF}
where
Q_{Ref} = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

1 metric ton = 1.1023 short tons

Greenhouse Gas Fugitive Emission Rate Estimates
Tank Farm - VOC Tank and Terminal 2
New Components

FIN:	P-VOC
EPN:	F-TK-VOC
Operating schedule (hr/yr):	8760

Fugitive Emission Calculations:

Emission Source	Source Count	Uncontrolled Emission Factor [1] (lb/hr-source)	Control Factor [2]	Hourly Emissions (lb/hr)
Valves - Gas	0	0.059	97%	0
Valves - Gas (DM)	0	0.059	75%	0
Valves - Light Liquid	500	0.024	97%	0.36
Valves - Light Liquid (DM)	0	0.024	75%	0
Valves - Heavy Liquid	0	0.00051	0%	0
Pumps - Light Liquid	0	0.251	85%	0
Pumps - Light Liquid	4	0.251	100%	0
Pumps - Heavy Liquid	0	0.046	0%	0
Flanges - Gas	0	0.00055	30%	0
Flanges - Light Liquid	800	0.00055	30%	0.308
Flanges - Heavy Liquid	0	0.00055	30%	0
Compressors	0	1.399	85%	0
Pressure Relief Valves [3]	0	0.35	100%	0
Sampling Connections	0	0.033	97%	0
Total Hourly Emissions				**0.668**
Total Annual Emissions				**2.93**

Sample Calculations:

Valve Emissions = (0 valves)(0.059 lb/hr-source)(1 - 0.97)
= 0 lb/hr

Annual Emissions = (0.668 lb/hr)(8760 hr/yr)(1 ton/2000 lb)
= 2.93 tons/yr

Emissions Speciation

Contaminant	Contaminant Code	Maximum Speciated Composition by Component (Wt %)	Hourly Speciated Emission Rates (lb/hr)	Annual Speciated Emission Rates (tons/yr)
Methane	60000	10.00%	0.067	0.293

NOTES:

(1) The emission factors used are refinery factors from the TCEQ Fugitive Guidance Document dated October 2000.
(2) The control factors are for a 28VHP program from the TCEQ Fugitive Guidance Document dated October 2000. Heavy liquid flanges have a 30% control efficiency applied as a result of the weekly AVO monitoring. Difficult to monitor (DM) sources are monitored annually.
(3) PRVs are routed to a flare or are equipped with a rupture disk upstream or downstream with a pressure gauge.

EMISSION RATES

Pollutant	GHG Annual Emissions (tons/yr)	Global Warming Potentials *	CO_2e Annual Emissions (tons/yr)
Methane (CH_4)	0.29	25	7.31
Total	0.29		7.31

Greenhouse Gas Fugitive Emission Rate Estimates
Gasoline Blending System
New Components

FIN:	P-GB
EPN:	F-GB
Operating schedule (hr/yr):	8760

Fugitive Emission Calculations:

Emission Source	Current Source Count	Uncontrolled Emission Factor [1] (lb/hr-source)	Control Factor [2]	Hourly Emissions (lb/hr)
Valves - Gas	0	0.059	97%	0
Valves - Gas (DM)	0	0.059	75%	0
Valves - Light Liquid	100	0.024	97%	0.072
Valves - Light Liquid (DM)	0	0.024	75%	0
Valves - Heavy Liquid	0	0.00051	0%	0
Pumps - Light Liquid	0	0.251	85%	0
Pumps - Light Liquid (sealess)	4	0.251	100%	0
Pumps - Heavy Liquid	0	0.046	0%	0
Flanges - Gas	0	0.00055	75%	0
Flanges - Light Liquid	150	0.00055	75%	0.0206
Flanges - Heavy Liquid	0	0.00055	30%	0
Compressors	0	1.399	85%	0
Pressure Relief Valves [3]	7	0.35	100%	0
Sampling Connections	0	0.033	97%	0
Total Hourly Emissions				**0.0926**
Total Annual Emissions				**0.406**

Sample Calculations:

Valve Emissions = (0 valves)(0.059 lb/hr-source)(1 - 0.97)
= 0 lb/hr

Annual Emissions = (0.0926 lb/hr)(8760 hr/yr)(1 ton/2000 lb)
= 0.406 tons/yr

Emissions Speciation

Contaminant	Contaminant Code	Maximum Speciated Composition by Component (Wt %)	Hourly Speciated Emission Rates (lb/hr)	Annual Speciated Emission Rates (tons/yr)
Methane	60000	10.00%	0.009	0.041

NOTES:

(1) The emission factors used are refinery factors from the TCEQ Fugitive Guidance Document dated October 2000.
(2) The control factors are for a 28VHP program from the TCEQ Fugitive Guidance Document dated October 2000. Heavy liquid flanges have a 30% control efficiency applied as a result of the weekly AVO monitoring. Difficult to monitor (DM) sources are monitored annually.
(3) PRVs are routed to a flare or are equipped with a rupture disk upstream or downstream with a pressure gauge.

EMISSION RATES

Pollutant	GHG Annual Emissions (tons/yr)	Global Warming Potentials *	CO_2e Annual Emissions (tons/yr)
Methane (CH_4)	0.04	25	1.01
Total	0.04		1.01

COOLING TOWERS

FHR is proposing to construct a new Mid Plant Cooling Tower No. 2 (44EF2) in the Mid-Plant area.

General Process Description

The West Refinery is provided cooling water from a number of cooling towers throughout the refinery. The cooling towers are equipped with an air-stripping system and are monitored monthly.

Emissions Data

Emission rate calculations for the following sources listed below are provided at the end of this section.

FIN	EPN	Source Name
44EF2	F-S-202	Mid Plant Cooling Tower No. 2

CH_4 emission rates from the new cooling tower is estimated based on the VOC emission rate and assumed maximum estimated weight percent methane of 10%. The cooling tower VOC emission rate is estimated based on an emissions factor of 0.7 lb/MMgal from AP-42 Table 5.1-2 and the water circulating flow rate.

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its GWP. CO_2e emission rates for each GHG are estimated by multiplying the emission rates for each GHG by its GWP value provided in Table A-1 of 40 C.F.R. Part 98, Subpart A.

COOLING TOWER GREENHOUSE GAS EMISSIONS
Potential to Emit

Cooling Tower	EPN	FIN	Flowrate (gpm)	VOC Emission Factor * (lb/MMgal)	VOC Emission Rate * (tons/yr)	Weight % Methane (CH_4) (%)	GHG Emissions (tons/yr)	Global Warming Potential **	CO_2e Emissions (tons/yr)
Mid Plant Cooling Tower No. 2	F-S-202	44EF2	30000	0.7	5.52	10	0.55	25	13.80

* Cooling tower VOC emissions are estimated with an emissions factor of 0.7 lb/MMgal from AP-42 Table 5.1-2, dated January 1995. The cooling water is monitored for VOC.
** Global warming potentials are from Table A-1 in 40 CFR 98, Subpart A.

PLANNED MAINTENANCE, START-UP, AND SHUTDOWN EMISSIONS

Increased GHG emissions are expected from planned maintenance, start up, and shutdown (MSS) activities associated with the construction of the new Sat Gas No. 3 Unit and for new storage tanks, which are not sources of GHG emissions during normal operations, but can emit GHGs during maintenance activities.

General Process Description

Various maintenance activities have fugitive emissions associated with them.

Vessel and Equipment Openings after Decommissioning

Once equipment has been cleaned, blinds for maintenance are installed. This requires opening the equipment to atmosphere releasing any residual VOC/methane to the atmosphere.

Controlling Fugitive Emissions from MSS Activities

The fugitive emissions from some MSS activities are routed to a control device which generates GHG emissions from combustion. Below is a table summarizing these activities and the control device used for each activity.

Activity	**Control Device Used**
Vacuum Truck Loading	Carbon Canister, Engine, Thermal Oxidizer
Tank Degassing	Engine, Thermal Oxidizer
Tank Refilling after Degassing or Product Change	Engine, Thermal Oxidizer

Emissions Data

Emission rate calculations for the following sources listed below are provided at the end of this section

FIN	EPN	Source Name
MSSFUGS-DC	MSSFUGS-DC	Miscellaneous MSS Fugitive Emissions For Domestic Crude Project

MSS emission rates are calculated from vessel and equipment openings and from the combustion emissions as a result of controlling the fugitive emissions from various activities. The MSS emissions from these categories are summed to get a total emission rate from miscellaneous MSS fugitive emissions for the domestic crude project.

MSS Fugitive Emissions from Process Vessel and Equipment Openings to Atmosphere

GHG emission rates from process vessel and equipment openings are estimated based on the volume released to the atmosphere and the GHG content. Volume and GHG content represented in the calculations are used to estimate annual emission rates conservatively and may vary.

Combustion Emissions from Controlling MSS Fugitive Emissions

CO_2 emission rates are estimated using Equation C-1b and the emission factor for "Crude Oil" in Table C-1 in 40 C.F.R. Part 98, Subpart C and converting from metric tons to short tons. CH_4 and N_2O are estimated using Equation C-8b and the emission factors for "Petroleum" in Table C-2 in 40 C.F.R. Part 98, Subpart C and converting from metric tons to short tons. The factors for "Crude Oil" and "Petroleum" from Tables C-1 and C-2 are used rather than factors for natural gas because they result in more conservative emission rate estimates.

CO_2e emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its GWP. CO_2e emission rates for each GHG are estimated by multiplying the emission rates for each GHG by its GWP value provided in Table A-1 of 40 C.F.R. Part 98, Subpart A.

Start-up/Shutdown/Maintenance Fugitive Emissions
Emissions Summary
EPN MSSFUGS-DC

Event	CO_2 Emission Rates (ton/yr)	CH_4 Emission Rates (ton/yr)	N_2O Emission Rates (ton/yr)	GHG Emission Rates (ton/yr)	CO_2e Emission Rates (ton/yr)
Equipment Openings		0.05		0.05	1.25
Controlling MSS Activities	228	0.010	0.0018	228	229
Total	**228**	**0.06**	**0.0018**	**228**	**230**

Start-up/Shutdown/Maintenance Fugitive Emissions
GHG Emissions from Vessel and Associated Piping/Equipment Openings to Atmsophere
EPN MMSFUGS-DC

Total Annual Flow Rate to the Atmosphere:	120,000	scf/yr
Maximum VOC Conent in the Vent Gas:	10000	ppmv
Assumed Molecular Weight of VOC to the Atmosphere:	62	lb/lb-mole
Methane Weight % in VOC:	50	%

VOC Emissions

$$\text{Annual VOC} = \frac{120000\ \text{scf vent gas}}{\text{yr}} \left| \frac{0.01\ \text{scf VOC}}{\text{scf vent gas}} \right| \frac{\text{lb-mol VOC}}{379.5\ \text{scf VOC}} \left| \frac{62\ \text{lb VOC}}{\text{lb-mol VOC}} \right| \frac{\text{ton VOC}}{2000\ \text{lb VOC}} = 0.10\ \text{tons/yr}$$

GHG Emissions

$$\text{Annual Methane} = \frac{0.1\ \text{tons VOC}}{\text{yr}} \left| \frac{50\ \text{tons Methane}}{100\ \text{tons VOC}} \right. = 0.05\ \text{tons Methane/yr}$$

Pollutant	GHG Annual Emissions (tons/yr)	Global Warming Potentials *	CO_2e Annual Emissions (tons/yr)
Methane (CH_4)	0.05	25	1.25
Total	0.05		1.25

Start-up/Shutdown/Maintenance Fugitive Emissions
GHG Emissions from Controlling MSS Activities
EPN MSSFUGS-DC

COMBUSTION UNIT DATA

Fuel Gas Firing Capacity, HHV:	10	MMBtu/hr, HHV
Operating Hours	278	hrs/yr

EMISSION FACTORS

Pollutant	Emission Factor (kg/MMBtu) *	Emission Factor (lb/MMBtu)	Global Warming Potentials **
Carbon Dioxide (CO_2)	74.49	164.22	1
Methane (CH_4)	0.003	0.0066	25
Nitrous Oxide (N_2O)	0.0006	0.00132	298

* The control device combusts propane and other petroleum vapors. The CO_2 emission factor is from 40 CFR 98, Table C-1 for crude oil, which is the highest factor for all types of vapors combusted. The CH4 and N2O factors are from 40 CFR 98, Table C-2 for petroleum.

** Global warming potentials are from Table A-1 in 40 CFR 98, Subpart A.

EMISSION RATES

Pollutant	GHG Annual Emissions (tons/yr)	CO_2-e Annual Emissions (tons/yr)
Carbon Dioxide (CO_2)	228	228
Methane (CH_4)	0.010	0.250
Nitrous Oxide (N_2O)	0.0018	0.536
Total	228	229

Emission rates are calculated using equations C-1b and C-8b and converting from metric tons/yr.

Equation C-1b from 40 CFR 98, Subpart C
CO_2 (metric tons/yr) = 0.001 x Gas x EF
where
Gas = Annual propane/petroleum vapor usage (MMBtu)
EF = Fuel specific default CO_2 emission factor for crude oil from Table C-1 (kg/MMBtu)

Equation C-8b from 40 CFR 98, Subpart C
CH_4 or N_2O (metric tons/yr) = 0.001 x Gas x EF
where
Gas = Annual propane/petroleum vapor usage (MMBtu)
EF = Fuel specific default CH_4 or N_2O emission factor for petroleum from Table C-2 (kg/MMBtu)

1 metric ton = 1.1023 short tons

Section 5.0

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

Introduction

As established in Section 3.0 of this application, the proposed project constitutes a major modification at an existing major source of GHG emissions. Therefore, an analysis of Best Available Control Technology (BACT) is required as part of the permit application. BACT is defined in 40 C.F.R. § 52.21(b)(12) as follows:

> *Best available control technology means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 C.F.R. parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.*

Scope of Analysis

The federal requirements for BACT review are outlined in 40 C.F.R. § 52.21(j)(3), as follows:

> *A major modification shall apply best available control technology for each regulated NSR pollutant for which it would result in a significant net emissions increase at the source. This requirement applies to each proposed emissions unit at which a net emissions increase in the pollutant would occur as a result of a physical change or change in the method of operation in the unit.*

This application addresses GHG emissions under the scope of the Federal Implementation Plan promulgated by EPA for the State of Texas, as outlined in 40 C.F.R. § 52.2305.

The above-quoted language restricts the scope of the BACT review to only those emission units that incur a net emissions increase as the result of a physical change to, or change in the method of operation of, the emission unit. As described in Section 1, this application includes emission units that are new, existing emission units that are modified (due to physical changes or changes in the method of operation), and affected upstream or downstream units. The affected upstream and downstream units are not subject to BACT in accordance with 40 C.F.R. § 52.21(j)(3).

Accordingly, the scope of this BACT analysis is limited to the new and existing modified units. The affected upstream and downstream units are considered only in determining whether a significant emissions increase of GHGs has occurred.

The following table lists the new and modified emission units within the scope of the BACT analysis:

Emission Unit Category	FIN	EPN	Description	PSD Emission Unit Type
Process Heaters	SATGASHTR	SATGASHTR	Sat Gas No. 3 Hot Oil Heater	New
	39BA3901	39BA3901	CCR Hot Oil Heater	Modified
Equipment Leak Fugitives	F-SATGAS3	F-SATGAS3	Sat Gas No. 3 Fugitives	New
	14-UDEX	F-14-UDEX	UDEX Fugitives	New (additional components)
	37	F-37	DHT Fugitives	New (additional components)
	39	F-39	NHT/CCR Fugitives	New(additional components)
	40	F-40	West Crude Fugitives	New (additional components)
	42	F-42	Mid Crude Fugitives	New (additional components)
	P-GB	F-GB	Gasoline Blender Fugitives	New (additional components)
	P-VOC	F-TK-VOC	VOC Tank/Loading Fugitives	New (additional components)
Cooling Towers	44EF2	F-S-202	Mid-Plant Cooling Tower No. 2	New
Planned Maintenance, Start-up, and Shutdown Activities	MSSFUGS-DC	MSSFUGS-DC	Planned Maintenance, Start-up, and Shutdown Activities	New (MSS for additional equipment)

BACT for each new and modified emission unit is addressed by emission unit category in the sections that follow, with distinctions made for individual units as needed.

BACT Analysis Methodology

The method used in this analysis follows the guidance in the EPA document titled “PSD and Title V Permitting Guidance for Greenhouse Gases”, EPA-457/B-11-001, March 2011 (“GHG Permitting Guidance”). In that document, EPA recommends the use of the EPA five-step, top-down process to determine BACT for GHG emissions. The steps in this process are as follows:

Step 1: Identify all available control technologies.
Step 2: Eliminate technically infeasible options.
Step 3: Rank remaining control technologies.
Step 4: Evaluate most effective controls and document results.

Step 5: Select the BACT.

Additional description of the methodology for each step is provided below:

Step 1: Identify all available control technologies.

The first step of a top-down BACT analysis is to identify all available control technologies for each emission unit. As explained in the EPA's Draft New Source Review (NSR) Workshop Manual (Oct. 1990) at B.17, "a technology is considered 'available' if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term."

Step 2: Eliminate technically infeasible options.

The second step involves the evaluation of the technical feasibility of each control option identified in Step 1 with respect to source-specific factors. Control technologies that are determined to be technically infeasible are eliminated from further consideration.

Step 3: Rank remaining control technologies.

In the third step, all remaining control technologies not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness, with the most effective control alternative ranked at the top.

Step 4: Evaluate most effective controls and document results.

Energy, environmental, and economic impacts are considered for each of the control options during Step 4 only if the most effective control option is not proposed as BACT: "However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top and review for collateral environmental impacts." EPA NSR Workshop Manual at B.8.

Step 5: Select the BACT.

In the fifth step, the most effective control option, based on the impacts quantified in Step 4, is proposed as BACT for the emission unit under review.

Resources Consulted

For preparation of its GHG BACT analysis, FHR followed the EPA guidance document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" EPA-457/B-11-001 (March 2011).

FHR also consulted the following resources to develop a list of available technologies and to complete the BACT analyses:

- EPA's Clean Air Act Advisory Committee (CAAAC) website;
- U.S. Department of Energy (DOE)/National Energy Technology Laboratory (NETL) websites;
- EPA's RACT/BACT/LAER Clearinghouse (RBLC);

- EPA white paper from October 2010 entitled "Available and Emerging Technologies for Reducing Greenhouse Gas Emission from the Petroleum Industry";
- EPA white paper from October 2010 entitled "Available and Emerging Technologies for Reducing Greenhouse Gas Emission from Industrial, Commercial, and Institutional Boilers";
- Massachusetts Institute of Technology's (MIT) website for Carbon Capture and Storage Technologies;
- Other EPA/State air quality permits, including GHG permits issued by EPA, state-issued GHG permits, and applications submitted to permitting authorities nation-wide,
- FHR engineering staff and contractor engineering staffs; and
- Applicable Standards under 40 C.F.R. Parts 60 (NSPS), 61 (NESHAP), and 63 (NESHAP/MACT).

Clean Fuels

Before analyzing BACT for specific emission units, we address the requirement to consider "clean fuels" as part of the BACT analysis. As demonstrated below, any requirement to burn "clean fuels" in process heaters and other combustion sources at the West Refinery would fundamentally "redefine" the sources, and is therefore not required to be considered as part of the BACT analysis.

As a refinery, the type of fuel combusted in the process heaters is inherent to the operation of the facility. Specifically, the refinery produces fuel gas as a result of its processes. That fuel gas is typically either combusted in process heaters or flared. Since combustion of the fuel gas in process heaters or boilers utilizes the energy in the fuel productively, this is preferred to flaring. Refinery process heaters and other combustion sources are designed specifically to combust that fuel gas and natural gas. As EPA has indicated "the initial list of control options for a BACT analysis does not need to include 'clean fuel' options that would fundamentally redefine the source. Such options include those that would require a permit applicant to switch to a primary fuel (*i.e.*, coal, natural gas, or biomass) other than the type of fuel that an applicant proposes to use for its primary combustion process."[3] In this case, the combustion sources to which BACT applies are designed to burn refinery fuel gas or natural gas. Substituting available refinery fuel gas with any other fuel "would fundamentally redefine the source."

Moreover, refinery gas and natural gas fuels are clean fuels with low GHG emissions. The CO_2 emission factor (kg CO_2/MMBtu) for the West Refinery fuel gas is approximately equivalent to the emission factor for natural gas as provided in 40 C.F.R. Part 98, Subpart C. The fuel gas GHG emission factor is 28% lower than the emission factor for #2 distillate fuel oil and 44% lower than the emission factor for coal as shown in the table below.[4]

[3] EPA, "PSD and Title V Permitting Guidance for Greenhouse Gases," http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf (March 2011).
[4] 40 C.F.R Part 98 subpart C, Table C-1

Fuel Carbon Content

Fuel Type	Default CO_2 emission factor ($kg\ CO_2/MMBtu$)[1]
Natural Gas	53.02
Fuel Gas	59.0
Distillate Fuel Oil No. 2	73.96
Coal (Lignite)	96.36

Source-Specific Analysis

The selection of BACT is done on a case-by-case basis by following each of the steps set forth above for each new and modified existing emissions unit. Because the steps are often the same for similar emissions units, we have grouped emissions units into categories where possible, as addressed in each of the following sections.

BACT for Process Heaters

GHG emissions from process heaters are the result of combustion of natural gas and refinery fuel gas. This analysis focuses on the emissions of CO_2 only. While other GHGs such as CH_4 and N_2O are present in trace quantities, there are no add-on controls for these pollutants generated by combustion sources such as the process heaters. To the extent measures are identified that reduce fuel use and thereby CO_2, the other GHGs will be reduced accordingly. Therefore, CO_2 serves as a useful surrogate for other GHGs, with proposed BACT limits expressed in terms of CO_2e.

Step 1: Identify all available control technologies.
We began our review of available technologies listed by EPA, and then we reviewed other permits and available technical measures and determined the list of available technologies.

In developing the list of design and operational practices to be considered as part of the heater design configurations, FHR worked closely with the engineering design firm developing the process designs for the project to identify and consider all available options to maximize the operating efficiency of each new or modified heater associated with the project. Since heaters of this scale and function are not mass produced, design and operating efficiency practices were incorporated into the design of each heater rather than selecting the heaters from "off-the-shelf."

As a starting point, the design firm considered the design and operating practices identified in EPA GHG guidance documents, pending GHG permit applications, and issued GHG permits. In addition to these concepts, the engineering design team was directed to consider any additional practices based on their experience with heater vendors on other projects they have executed. Using this approach, available efficiency measures have been integrated into the design/redesign and operational plans for the new/modified heaters.

In reviewing the resources outlined above, the following technologies were identified as potentially available for the refinery process heaters that will be newly constructed or modified as part of the project:

Technology	Description	Availability
Energy Efficient Design	Minimize GHG emissions by limiting amount of fuel burned based on design measures, such as: • Install Energy Efficient Burners • Draft/Trim Instrumentation and Controls • Waste Heat Recovery (Economizer / Air Preheater) • Insulation/Insulating Jackets • Reduce air leakage • Reduce slagging and fouling of heat transfer surfaces	Available
Energy Efficient Operating Practices	Minimize GHG emissions by limiting amount of fuel burned based on operational practices, such as: • Initial Heater Tuning and Testing • Annual Heater Tune-Up • Optimization	Available
Carbon Capture and	CCS technology is made up of three main steps:	Not available, but

Technology	Description	Availability
Sequestration (CCS)	• Capturing of the CO_2, • Transporting the captured CO_2 to a suitable storage location, and • Permanently storing the CO_2	voluntarily carried through the remainder of the 5 step process

As shown in the table above, energy efficient design and operational measures are considered available. For the reasons described below, carbon capture and sequestration is not an available technology for this project at this time; however, it has been carried through the five-step process on a voluntary basis.

Efficient design and operating practices are paramount in minimizing GHG emissions for process heaters. By designing and operating heaters with a higher efficiency, less fuel is burned, reducing the amount of each GHG pollutant produced as a product or byproduct of combustion. The EPA emission factors for GHGs from process heaters are established on the basis of fuel consumption measured in MMBtu of fuel as-fired. Improvements in overall heater efficiency ensure that more of the energy (in terms of MMBtu fired) is recovered as useful output in the process instead of being lost as unutilized heat that is discharged as high temperature exhaust gases. This reduces total fuel consumption and limits GHG emissions.

In previous applications, EPA staff has requested benchmarking data to compare efficiency improvements associated with process heater control technologies. Although FHR does not believe that benchmarking is an appropriate method for determining BACT, based on the references cited above, the following benchmarks of estimated ranges of efficiency improvement are available for the identified technology measures:

Technology Measure	Estimated Efficiency Improvement	Reference
Reduce Energy Loss by Minimizing Excess O2/Stack Flow (Combustion Air Controls-Limitations on Excess air)	1-3%	EPA white paper from October 2010 entitled “Available and Emerging Technologies for Reducing Greenhouse Gas Emission from the Petroleum Industry”, page 12
Reduce Energy Loss by Minimizing Stack Temperature (Air preheat/heat recovery)	10-15%	EPA white paper from October 2010 entitled “Available and Emerging Technologies for Reducing Greenhouse Gas Emission from the Petroleum Industry”, page 13
Reduce Conductive Heat Energy Loss (Improved Insulation)	3-13% (as described for boilers)	EPA white paper from October 2010 entitled “Available and Emerging Technologies for Reducing Greenhouse Gas Emission from the Petroleum Industry”, page 13

Carbon Capture and Sequestration (CCS)

Pursuant to EPA's 1990 Draft PSD manual, the availability of an add-on pollution control technology under Step 1 should be considered "based on the physical and chemical characteristics of the pollutant-bearing emissions stream"[5] and "[t]echnologies which have not yet been applied to (or permitted for) full scale operation need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice."[6] Using these principles, EPA has classified CCS as an add-on pollution control technology that is "available" for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (*e.g.*, hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).[7] The proposed project involves none of these types of facilities. In contrast, the CO_2 streams from project combustion sources are emitted in much lower volumes and are highly diluted compared to these other sources. For example, the estimated CO_2 concentration for the gas-fired heaters that are being newly constructed or modified as part of this project will fall in a range of 6-10%. By contrast, the concentrations of CO_2 in coal-fired, IGCC utility boiler streams, for which EPA determined in its recently proposed Electric Utility GHG New Source Performance Standards (NSPS) that CCS is technically feasible and economical, are on the order of 30-32%. In fact, EPA's recently proposed NSPS for GHGs from electric generating units[8] highlights the importance of these distinctions. Speaking to exhaust streams from natural gas-fired combustion turbines—streams similar in concentration of GHGs to the exhaust streams from the process heaters that are part of the proposed project—EPA noted that the Agency did not know of any demonstrations of natural gas combined cycle turbines implementing CCS that would justify setting a national standard.

Because FHR is unaware of any CCS add-on controls that have been demonstrated at this scale on a highly diluted CO_2 stream, CCS is not available for the project. FHR has nevertheless voluntarily included CCS in the remainder of this top-down analysis as an add-on technology.

Step 2: Eliminate technically infeasible options.

The second step requires the evaluation of the technical feasibility of each control option identified in Step 1 with respect to source-specific factors. Technologies that are determined to be infeasible are eliminated from further consideration. Based on the options carried forward from Step 1, the following table summarizes technical feasibility.

---

[5] Draft New Source Review (NSR) Workshop Manual (Oct. 1990) at B.8.

[6] *Id.* at B.11.

[7] EPA-457/B-11-001, March 2011, PSD and Title V Permitting Guidance for Greenhouse Gases, Page 32.

[8] *See*, U.S. EPA, "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units; Proposed Rule" (Sep. 20, 2013), *available at* http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf [hereinafter "GHG NSPS"].

Technology	Description	Feasibility
Energy Efficient Design	Minimize GHG emissions by limiting amount of fuel burned based on design measures, such as: • Install Energy Efficient Burners • Draft/Trim Instrumentation and Controls • Waste Heat Recovery (Economizer / Air Preheater) • Insulation/Insulating Jackets • Reduce air leakage • Reduce slagging and fouling of heat transfer surfaces	Technically Feasible
Energy Efficient Operating Practices	Minimize GHG emissions by limiting amount of fuel burned based on operational practices, such as: • Initial Heater Tuning and Testing • Annual Heater Tune-Up • Optimization	Technically Feasible
Carbon Capture and Sequestration	CCS technology has three main elements: • Capture of the CO_2, • Transport the captured CO_2 to a suitable storage location, and • Permanent storage of CO_2	Technically infeasible, but voluntarily carried through the remainder of the 5 step process

As shown in the table above, energy efficient design and operational measures are considered technically feasible. For the reasons described below, FHR does not believe that CCS is technically feasible at this time; however, it has been carried through the rest of the five-step process on a voluntary basis.

CARBON CAPTURE AND SEQUESTRATION

A successful CCS technology must be capable of capturing CO_2 from an exhaust stream, transporting that CO_2 to a storage location and, finally, permanently storing and sequestering the transported CO_2. Therefore, to be considered a feasible control technology, CCS must include the following:

- Technology for removing CO_2 from the exhaust stream, also referred to as a carbon *capture* technology.
- A feasible means of *transporting* the quantities of CO_2 captured to the storage location.
- A viable place for permanent *storage* of the CO_2 given the physical form that it is in after removal (*i.e.*, gas, liquid, or solid). This is typically referred to as *carbon sequestration*.

Having a technically feasible carbon capture technology that is based—for example—on removing CO_2 in the gaseous form but that does not include viable long-term storage or a CO_2 transport system to move captured CO_2 to the storage site will not accomplish the goal of removing CO_2 from the atmosphere. Therefore, for CCS technology to be considered a technically feasible control option for consideration as BACT at FHR, carbon capture, carbon transport, and carbon storage must all be examined and deemed both available and technically feasible for the proposed project.

FHR evaluates below the technical feasibility of each aspect of CCS.

Carbon Capture

Carbon capture has not been installed and operated successfully (*i.e*., demonstrated) on a combustion source similar to the process heaters that make up this project. FHR has reviewed air construction permits issued by EPA Region 6 that address GHG BACT, and none of them have required CCS as BACT for process heaters or similar combustion sources.

Carbon capture is not "applicable" to the combustion sources because there is no specific evidence that there is a commercially available carbon capture system of the scale that would be required to control the CO_2 emissions for the sources that are part of the Project. Carbon capture is not "applicable" to the combustion sources because of the physical and chemical characteristics of the pollutant-bearing gas stream of the sources under review. In particular, the process heaters under evaluation in this BACT analysis emit relatively small amounts of CO_2, and what CO_2 is emitted is highly diluted (6-10%) in the exhaust gas.[9] The low concentration and low pressure of the process heater exhaust complicates the absorption and desorption of the CO_2 making capture of CO_2 significantly more difficult than from highly concentrated streams. The difficulties associated with low concentration low-pressure streams also increase the energy requirements of the carbon capture system.

As noted above, EPA's recently proposed New Source Performance Standards for GHGs from electric generating units[10] confirms that carbon capture is not technically feasible for natural gas-fired combustion units. There, EPA stated:

> The EPA is aware of only one NGCC unit that has implemented CCS on a portion of its exhaust stream. . . . The EPA is not aware of any demonstrations of natural gas combined cycle (NGCC) units implementing CCS technology that would justify setting a national standard. Further, the EPA does not have sufficient information on the prospects of transferring the coal-based experience with CCS to NGCC units. In fact, CCS technology has primarily been applied to gas streams that have a relatively high to very high concentration of CO_2 (such as that from a coal combustion or coal gasification unit). The concentration of CO_2 in the flue gas stream of a coal combustion unit is normally about four times higher than the concentration of CO_2 in a natural gas-fired unit . . . .[11]

These conclusions are supported by the *Report of the Interagency Task Force on Carbon Capture and Storage*, August 2010. The Task Force was composed of fourteen Executive Departments and Federal Agencies and was co-chaired by DOE and EPA. The purpose of the Task Force was to propose "a plan to overcome the barriers to the widespread, cost-effective deployment of CCS within ten years." The Task Force report summarized the status of CCS technology, listed difficulties associated with implementing the technology, and stated that,

---

[9] EPA-457/B-11-001, March 2011, PSD and Title V Permitting Guidance for Greenhouse Gases, Page 32

[10] *See*, U.S. EPA, "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units; Proposed Rule" (Sep. 20, 2013), *available at* http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf [hereinafter "EGU NSPS"].

[11] *Id.* at 35.

although CCS technology is available, it is not ready for widespread implementation, and is therefore, not considered to have been demonstrated. Difficulties discussed in the report that would be applicable to this Project include:

- A high volume of combustion flue gas would have to be treated due to the low CO_2 concentration in the exhaust stream; and
- Contaminants in the exhaust gas, including oxides of nitrogen, particulate matter, and sulfur dioxide, could degrade the materials used to capture the CO_2.

The non-commercial availability of these technologies for high volume, low carbon concentration streams is further evidenced by DOE/NETL research as recent as 2011, which confirms that commercial CO_2 capture technology for large-scale natural gas combustion sources is not yet available and indicates that it may take until 2020 for a widespread deployment of the technology.[12]

For these reasons, FHR concludes that carbon capture is not technically feasible for gas-fired combustion units such as the process heaters.

Carbon Storage

FHR evaluates the technical feasibility of carbon storage in the following subsections, including discussions of whether carbon storage is "demonstrated," "available," or "applicable."

Currently-available forms of EOR are not technically feasible as permanent geologic sequestration of CO_2. FHR considers only storage techniques with the purpose of long-term storage as BACT-qualifying GHG storage technologies. While enhanced oil recovery (EOR) is currently being tested and evaluated for long-term storage as part of the DOE studies discussed in more detail below, existing EOR practices at this time are not considered as demonstrated permanent sequestration.

In its EGU NSPS, EPA asserted that "CO_2-EOR is the fastest-growing EOR technique in the U.S. * * * A well-established and expanding network of pipeline infrastructure supports CO_2-EOR in these areas. * * * [and] there are currently twenty-three industrial source CCS projects in twelve states that . . . will supply captured CO_2 for the purposes of EOR." *Id.* 230–31. Consequently, EPA determined that "areas in close proximity to active EOR locations, including the pipelines that extend into those locations, to be places where EOR is available." However, later in the proposed rule, EPA clarifies what it means by "technically feasible" EOR—only those EOR facilities that comply with 40 C.F.R. Part 98, Subpart RR. *Id.* at 279 ("If the captured CO_2 is sent offsite, then the facility injecting the CO_2 underground must report under 40 CFR Part 98 subpart RR."). To comply with Subpart RR, an EOR operation must include CO_2 injection wells that are permitted as Class VI under the Underground Injection Control program, or hold a monitoring, reporting, and verification (MRV) plan approved by EPA. See 40 C.F.R. § 98.440(c)(1)–(2). The NSPS distinction between Subpart RR and non-Subpart RR EOR is consistent with that of EPA's Office of Water. There, EPA distinguishes between enhanced recovery ("ER") the principal purpose of which is EOR, and ER the principal purpose of which is

[12] DOE/NETL, *Carbon Sequestration Program: Technology Program Plan* (February 2011), 10.

geologic sequestration ("GS"). EOR is authorized using Class II wells (non-Subpart RR compliant), while GS is subject to Class VI permitting (Subpart RR compliant).13

EPA appears to have proposed this requirement to avoid many of the uncertainties associated with carbon storage at non-Subpart RR EOR facilities. While the EOR projects cited by EPA in the EGU NSPS are undoubtedly important in researching the feasibility of carbon capture, use, and sequestration, there are significant issues surrounding CO_2 ownership, short- and long-term monitoring, the type of injection wells to be used in EOR applications, and the permanence of sequestration in these fields (*e.g.*, whether future earthquakes may breach CO_2 sequestration sites). Many commenters have raised precisely these concerns in objecting to BACT analyses that rely on non-Subpart RR EOR to permanently sequester CO_2. The necessary implication of EPA's analysis in the EGU NSPS is that non-Subpart RR EOR is insufficient to satisfy the permanence element of geologic sequestration. Non-Subpart RR EOR can therefore not qualify as BACT.

Based on Part 98 reported data available as of the date of this application, FHR is aware of no current EOR operation that is compliant with Subpart RR.[14] Without a willing Subpart RR EOR buyer of CO_2, EPA's recent response to public comments in the La Paloma GHG permitting action correctly describes any EPA-imposed requirement to arrange for EOR disposal of CO_2 as an "attempt to arrange a contractual marriage through a BACT determination."[15] Such contracting is even more difficult when one party is unwilling at this time to subscribe to Subpart RR requirements. Accordingly, Subpart RR EOR facilities are not "demonstrated" for the purposes of BACT—they have not been "installed and operated successfully on the type of source under review." For the same reasons that Subpart RR EOR facilities are not "demonstrated," they are also neither "available" nor "applicable" as BACT controls. FHR therefore concludes that Subpart RR EOR facilities are technically infeasible for purposes of BACT. Nevertheless, we voluntarily include in the Step 4 cost-effectiveness analyses an evaluation of EOR as a hypothetical surrogate for permanent sequestration.

Permanent geological sequestration of CO_2 is not a demonstrated technology. Geologic CO_2 storage is still in the development phase and currently is being tested by the US

[13] EPA 816-P-13-004, December 2013, Geologic Storage of Carbon Dioxide: Draft Underground Injection Control (UIC) Program Guidance on Transitioning Class II Wells to Class VII Wells, pages 14–15.

[14] This is the case because under commonly understood principles of state oil and gas law, EOR operators have constitutional (in some states), statutory, regulatory, and contractual obligations to avoid "waste" of natural resources—in this case oil and gas. *See, e.g.*, *Exxon Corporation, et al. v. Laurie T. Miesch et al.*, 180 S.W. 3d 299, 318 (Tex. App. 2005) (stating the conservation and development of all natural resources is a "public right and duty" and the preservation of the State's natural resources "is an issue of constitutional dimension"). The Class VI program is based on the Class I waste disposal regulations, and treats CO_2 as a waste to be disposed of, rather than a commodity to be used in the production of oil and gas. This emphasis on waste disposal, rather than resource production, permeates the entire Class VI program, and makes it more difficult technically and economically to operate an EOR field without wasting some of the oil resources. This is particularly true in light of the uncertainties surrounding how EPA will actually implement its new Class VI program. As a consequence, FHR is aware of no expectation that EOR operators intend in the future to comply with Subpart RR.

[15] Response to Public Comments at 32, *available at* http://www.epa.gov/region6/6pd/air/pd-r/ghg/la-paloma-response11062013.pdf. EPA also notes in the La Paloma response that requiring CCS in these circumstances would "require the applicant to clear numerous logistical hurdles such as obtaining contracts for offsite land acquisition for pipeline right-of-way, construction of the transportation infrastructure, and develop a customer(s) who is willing to purchase the CO_2." *Id.* EPA also notes that the actual price of CO_2 could vary depending on a number of factors including CO_2 availability in the area, the nature of the EOR reservoir and the price per barrel of oil. And, EPA concludes that, for the La Paloma project, that "[t]hese obstalces alone make CCS for this specific site and project economically infeasible and possibly even technically infeasible." *Id.* The same holds true for the FHR project.

Department of Energy at a number of sites as described in the table below. The National Energy Technology Laboratory (NETL) Carbon Storage Program, which is part of the Department of Energy's (DOE) national laboratory system, is in the process of developing and evaluating technologies that will not be available for commercial deployment until 2020.[16] Large-scale (greater than 1 million metric tons CO_2 injected) carbon sequestration projects are at the very early stages of testing and development and it is still unclear, at this time, what the long term outcome of these projects will be. The NETL is currently working on (and in some instances economically supporting) a number of large-scale field tests in different geologic storage formations to confirm that CO_2 capture, transportation, injection, and storage can be achieved safely, permanently, and economically over extended periods of time. Hence, such technologies are not considered "available". *See In re: Cardinal FG Company*, 12 E.A.D. 153 (E.A.B. 2005) ("[T]echnologies in the pilot scale testing stages of development would not be considered available for BACT review", quoting from EPA, Draft New Source Review Workshop Manual (Oct. 1990) at B-18).

Carbon sequestration poses a number of issues before the technology can be safely and effectively deployed on the commercial scale. For example, according to the NETL, the following items still need to be proven and documented to validate that CCS can be conducted at a commercial scale.[17]

- Permanent storage must be proven by validating that CO_2 will be contained in the target geologic formations.
- Technologies and protocols must be developed to quantify potential releases and ensure that the projects do not adversely impact underground sources of drinking water (USDWs) or cause CO_2 to be released to the atmosphere.
- Long term monitoring (includes tracking of the CO_2 plume to ensure it stays within the intended containment zone) of the migration of CO_2 during and after project completion must be completed to show permanent containment has been achieved.
- Methodologies to determine the presence/absence of release pathways must be developed.
- Effective regulatory and legal framework must be developed for the safe, long term injection and storage of CO_2 into geological formations, including post-closure requirements. The table below has a few examples of current large-scale carbon sequestration projects that are taking place in the United States and their respective state of development. None of these demonstration projects has progressed to the stage where it is a proven technology for CO_2 storage.

[16] NETL, "Technologies: Carbon Storage", http://www.netl.doe.gov/technologies/carbon_seq/index.html. Though the NTEL report identifies geologic formations that *could* sustain geologic sequestration of CO_2, it would be entirely speculative for FHR to acquire rights to such formations, conduct the necessary research and development to assess their suitability for sequestration, develop the injection and monitoring systems, and resolve the outstanding transport, fate, and potentially adverse human health and environmental impacts from CO_2 storage. Accordingly, FHR has not included a detailed analysis of such a speculative control technology. FHR has also not included in its analysis the prospect of sending CO_2 from the project to a single EOR field. Tying the ability to operate the West Refinery to the production at one EOR field—as opposed to linking the West Refinery to a CO_2 pipeline serving numerous EOR fields—would be imprudent from a business perspective because a failure of production, or a shut-in of production due to market conditions, would interfere with the operations of the refinery.

[17] NETL, "Carbon Storage: Large-Scale Field Tests" http://www.netl.doe.gov/technologies/carbon_seq/largescale.html

Project Sponsor/Project Location	CO_2 Source	Reservoir	Current State of Development[18]
Southwest Regional Carbon Sequestration Partnership (SECARB) Cranfield Oil Field, Natchez, Mississippi	Large volumes of CO_2 are delivered by Denbury's Sonat Pipeline, which is supplied by abundant natural CO_2 from Jackson Dome. A smaller quantity is captured from a 25 MW slipstream at Southern Company's Plant Barry.	Tuscaloosa Sandstone Formation, down dip of the mature Cranfield Oil Field	The SECARB project currently is injecting approximately 1.5 million tons/yr of CO_2. Injection at the Cranfield site began in 2009 and was the first in the US to reach the CO_2 injection volume of 1 million metric tons. Capture of up to 150,000 tons per year of anthropogenic CO_2 from Plant Barry began in mid-2011. As of August 2013, approximately 4.7 million tons of CO_2 has been sequestered. Site monitoring, including CO_2 plume migration tracking, is still ongoing.
Plains CO_2 Reduction (PCOR)/Williston Basin, western North Dakota	CO_2 would be supplied via post combustion capture from Basin Electric Power Cooperative Antelope Valley Station (coal-fired power plant).	EOR at an oil field in Williston Basin	Basin and PCOR planned the injection of approximately 0.5 to 1 million tons/year into a deep carbonate reservoir for the dual purpose of CO_2 storage and EOR. However, in December of 2010, the project was indefinitely placed on hold due to economic infeasibility. The front end engineering and design (FEED) study indicated the project could cost up to $500 million.[19]
Plains CO_2 Reduction (PCOR)/Bell Creek Oil Field, Montana	CO_2 will be captured at the Lost Cabin Gas Plant in Wyoming and conveyed by Denbury's 232 mile Greencore pipeline.	EOR at Bell Creek Oil Field in Muddy Formation Sandstones	Construction of the capture facilities began in 2011 and the pipeline was completed in 2012. Injection of CO_2 commenced in August 2013. An injection rate of at least 1 million tons/yr is planned. Monitoring and verification of CO_2 will be conducted, and CO_2 in the produced oil will be re-injected to the field.

[18] Massachusetts Institute of Technology. Carbon Capture and Sequestration Project Database. Accessed October, 2013 at: http://sequestration.mit.edu/tools/projects/index.html.

[19] Dakota Gasification Company. "Basin Electric Postpones CO_2 Capture Project." December 17, 2010. Available at: http://www.dakotagas.com/News_Center/News_Releases/basin-electric-postpones-co2-capture-project.html. Note that while Dakota Gasification Company supplies CO_2 to the Weyburn/Midale oil field in Canada for enhanced oil recovery, it is not a NETL-sponsored CO_2 storage project.

Project Sponsor/Project Location	CO_2 Source	Reservoir	Current State of Development[18]
Midwest Geological Sequestration Consortium (MGSC) and Archer Daniels Midland (ADM)/Decatur, Illinois	CO_2 is being captured from the ADM ethanol plant located in Decatur IL. CO_2 is captured using Alstom's amine process.	Mt. Simon Sandstone	The project is planned to sequester approximately 1.1 million tons of CO_2 over three years. A comprehensive Measurement, Verification, and Accounting (MVA) program, including shallow groundwater, soil gas, resistivity, and atmospheric monitoring has been started and will continue through injection and for three years after injection is complete. Injection of CO_2 began in November 2011.
Midwest Regional Carbon Sequestration Partnership (MRCSP)/Otsego County, Michigan	CO_2 is supplied by a DTE natural gas processing plant where gas is produced from the Antrim Shale.	Depleted oilfields in Northern Reef Trend	Injection of up to 1,000 tons/day began in April 2013 with a total injection of 500,000 tons planned. Monitoring and tracking of the injected CO_2 began in July 2013 to quantify how much is retained in the formation after the oil is removed.
Big Sky Carbon Sequestration Partnership (BSCSP)/Toole County, Montana	CO_2 is obtained from a natural source within the Kevin dome	Duperow Formation saline aquifer	This eight year project began in late July 2011 and is scheduled for completion in 2019. The injection start date is scheduled for 2013, although no announcement of commencement has yet been made. A total injection of 1 million tons of CO_2 is planned. BSCSP is currently working on site characterization including permitting, seismic surveying, environmental monitoring and geological monitoring and analysis.
The Southwest Regional Partnership on Carbon Sequestration (SWP)/Gordon Creek Field, Utah	CO_2 will be obtained from a natural source within the Farhnam Dome.	Jurassic Entrada Formation and Navajo Sandstone saline aquifer	Site evaluation was completed in 2009, CO_2 injection (up to 1 million tons per year for 3 or 4 years) was planned to begin in the fall of 2012. However, no announcement of initiation of injection has been made to date. The project will include continuous monitoring and measurements both during and post-injection to verify permanent storage.
West Coast Regional Carbon Sequestration	None.	Martin Formation	A drill stem test revealed that there was insufficient permeability for CO_2 storage at the site.[20] WESTCARB has

[20] WESTCARB. "Fact Sheet for Partnership Field Validation Test." Revised October 28, 2009. Available at: http://www.westcarb.org/pdfs/FACTSHEET_AZPilot.pdf.

Project Sponsor/Project Location	CO_2 Source	Reservoir	Current State of Development[18]
Partnership (WESTCARB)/Cholla Power Plant near Holbrook, Arizona			no active large scale CCS demonstration projects planned at this time.

Although the table shows that a number of large-scale sequestration projects have begun the first steps (*i.e.,* injection of CO_2) for demonstration of CO_2 sequestration technology, it has not yet been proven that these injection sites will be able to provide long-term CO_2 storage. According to NETL's February 2011 report "Carbon Sequestration Program: Technology Program Plan," monitoring to confirm permanent CO_2 containment takes approximately five years.[21] Assuming that large-scale sequestration demonstration projects, like the ones listed above, begin CO_2 injection between now and 2015, carbon storage will still not be fully tested until 2020. This is consistent with the estimated timeline provided by NETL.

Because of the injection volume limitations of these projects, along with the uncertainty associated with the fate of CO_2 so injected, long-term geologic sequestration has not been successfully applied to the type of source under review in this application. Accordingly, permanent geologic sequestration is not a demonstrated technology for purposes of the application.

***Permanent geological sequestration of CO_2 is not an available technology*.** The large-scale CO_2 storage projects identified by NTEL have not yet reached the licensing and commercial stage of development. Indeed, these projects are being undertaken in public-private partnership arrangements, with significant financial support being provided by the Department of Energy.[22] Moreover, the stated purpose of the large-scale projects is to "validate that CCS can be conducted at a commercial scale."[23] In fact, the relatively small storage capacities of these projects (the largest of which is only 3.4 million metric tons) suggests that they are being conducted at a pilot scale, relative to the CO_2 that would be emitted at the West Refinery. Technologies in the pilot scale testing stages of development are not considered "available" technologies. Because these pilot scale projects have not yet reached the licensing and commercial stage of development, permanent geological sequestration of CO_2 is not an available technology.

***Permanent geological sequestration of CO_2 is not an applicable technology*.** The large-scale CO_2 storage projects identified by NTEL are incapable of accepting the volumes of CO_2 that would be produced at the West Refinery. NETL itself is assessing whether these projects have capacity to reliably store CO_2 long-term without adverse human health or environmental impacts, and so without firm findings and conclusions in this area, FHR cannot rely on these projects to provide permanent sequestration of its CO_2.

We therefore conclude that permanent sequestration is technically infeasible as a potential BACT sequestration technology. Nevertheless, we voluntarily include in the Step 4 cost-effectiveness analyses evaluations of permanent geologic sequestration as a hypothetically technically feasible control technology.

---

[21] NETL, "Carbon Sequestration Program: Technology Program Plan", February 2011. http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf

[22] Such financial support for clean coal technologies may well prohibit EPA from considering them as BACT. *See*, 26 U.S.C. § 42A(g), 42 U.S.C. § 15962(i) (disallowing technologies and emission reductions at clean coal projects receiving tax credits or financial assistance from the federal government from being considered as BACT). In addition, EPA recognizes that the deployment of CCS at privately-financed projects is disadvantaged in comparison to NTEL CCS projects with significant public financing. *See* Response to Public Comments for the ExxonMobil Chemical Company Baytown Olefins Plant at 13 (Nov. 25, 2013).

[23] *Id.*

Carbon Transportation

After capture and the identification of an acceptable storage location, the next activity in implementing CCS is CO_2 compression and transport.

***CO_2 transportation to permanent geological sequestration sites is not a demonstrated technology*.** For the West Refinery project (*i.e.*, a substantial-volume, privately-financed, anthropogenic CO_2 source requiring a highly reliable CCS system), there is no CO_2 pipeline that has been installed and operated successfully connecting a similarly sized source to a permanent geologic sequestration site with sufficient capacity to reliably accept such volumes over the lifetime of the project. Even if such a hypothetical pipeline were to be identified, it certainly has not been successfully operated in such a way as to support highly reliable operation of the anthropogenic source, particularly a source subject to stringent, continuous CO_2 emission limitations.

***CO_2 transportation to permanent geological sequestration sites is an available technology*.** Materials to construct pipelines capable of reliably transporting large volumes of CO_2 are generally available from commercial vendors. Accordingly, FHR concludes that CO_2 pipelines are an available technology.

***CO_2 transportation to permanent geological sequestration sites is not an applicable technology*.** The inescapable fact is that because there are no technically feasible, large-capacity, reliable, permanent geological sequestration sites, any CO_2 pipeline from the West Refinery project would be a pipeline to an indeterminate location. Moreover, even if one of the large-scale carbon sequestration projects in NETL's 2012 Atlas were hypothetically capable of serving the West Refinery, the logistical hurdles of constructing, owning, and operating a high-capacity CO_2 pipeline to one of those sites are high. For example, the closest non-EOR sequestration site noted by NETL would be the Archer Daniels Midland sequestration demonstration project near Decatur, Illinois, some 1,100 miles away from Corpus Christi.

These significant logistical issues associated with the utilization of that pipeline that could not be overcome within the project timeline include successful permitting, securing right-of-way (especially due the large number of landowners that could be involved), securing project funding (including potential government funding), and securing a lease or title to that site or a commercial contract with a pipeline company to deliver to their contracted site. Funding for CCS is a considerable logistical hurdle because CCS (a voluntary cost estimate is provided below) is cost-ineffective, as demonstrated in Step 4 below. Environmental considerations that would accompany construction of such a pipeline would also likely cause delays that could not be resolved within the project timeline. The EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases" EPA-457/B-11-001 (March 2011), states that:

> *While CCS is a promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases. As noted above, to establish that an option is technically infeasible, the permitting record should show that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review. EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and*

> *developing a site for secure long term storage. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard. Based on these considerations, a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture, and storage of GHGs are determined to be generally available from commercial vendors. Based on these considerations, a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture, and storage of GHGs are determined to be generally available from commercial vendors.*

CO_2 transportation to Subpart RR-compliant EOR facilities is neither demonstrated, nor applicable. The closest available commercial means to transport large volumes of CO_2 is the Denbury pipeline, which is over 200 miles away. A new pipeline would have to be run from the West Refinery to connect to the Denbury pipeline. Nevertheless, because the Denbury pipeline leads to an EOR field that is not Subpart RR compliant, and—along with the rest of the EOR industry—will not likely be modified to become Subpart RR compliant, CO_2 transportation for BACT purposes through the Denbury pipeline is neither demonstrated nor applicable. And for the reasons set forth above, FHR is aware of no Subpart RR-compliant EOR fields. A CO_2 pipeline from FHR's project to a hypothetical Subpart RR-compliant EOR field is thus currently technically infeasible.

Based on the current state of sequestration technologies and the limited availability of transport opportunities, CCS technology, as a whole, is considered technically infeasible for the FHR West Refinery project at this time.

<u>Step 3: Rank remaining control technologies.</u>

Under the third step, all remaining control technologies not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. In this case, implementation of energy efficient design and operational practices are not exclusive of each other, and would be ranked in combination at the top of the list as the only technically feasible control options available for the process heaters, with the potential for reducing GHG emissions by 10-15% in total.

For the reasons described above, CCS is not available or technically feasible at this time; however, it has been carried through the rest of the five-step process on a voluntary basis. If this technology were available and technically feasible, it would be ranked above the combination of efficient design and operational practices, with the potential for reducing GHG emissions by over 90%, which was relied upon for the cost analysis.

<u>Step 4: Evaluate most effective controls and document results.</u>

Energy, environmental, and economic impacts are considered for each of the control options during Step 4 only if the most effective control option is not proposed as BACT: "However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top and review for collateral environmental impacts." EPA NSR Manual at B.8.

FHR is proposing to implement efficient design and operational practices as BACT. This is the top control alternative that has been determined to be available and technically feasible. There are no significant expected adverse collateral energy, environmental, or economic impacts associated with the efficiency measures proposed as BACT.

Although FHR has shown CCS technology to be unavailable and technically infeasible, FHR has engaged Mustang Engineering to complete an initial project engineering and cost analysis for CCS to develop estimates for site-specific consideration as part of our project. The estimated costs demonstrate that CCS technology is ineffective on a cost basis and has adverse collateral energy and environmental impacts. Specifically, FHR relied on the engineering analysis to develop cost estimates to install the following equipment to implement CCS using an amine-based solvent absorption technology, which is the nearest to being considered "available":

- An amine capture skid for the proposed new Sat Gas No. 3 Hot Oil Heater
- An amine capture skid for the modified CCR Hot Oil Heater
- A shared amine regeneration, drying, and compression skid
- An additional ~350 MMBtu/hr (HHV) 150# Steam Boiler, which would be required for amine regeneration associated with the CCS system, but is not proposed without CCS
- An amine capture skid for the additional 150# Steam Boiler
- Pipeline right of way acquisition and construction to nearest available commercial CO_2 pipeline, which is located approximately 200 miles from the West Refinery and is used to transport CO_2 for EOR. Pipeline right of way acquisition and construction to the nearest hypothetical permanent geologic sequestration site near Decatur, Illinois—some 1,100 miles from the West Refinery—would be even higher.

The results of the analysis are summarized in the following table:

Description	Initial Capital Cost (+/-50%) ($)
Amine Capture Skid – Sat Gas No. 3 Hot Oil Heater	$14,000,000
Amine Capture Skid - CCR Hot Oil Heater	$29,000,000
Amine Capture Skid - 150# Steam Boiler	$25,000,000
Construct Added 150# Steam Boiler	$17,000,000
Amine Regen/Drying/Compression	$76,000,000
Pipeline Construction	$200,000,000
Total	$360,000,000

Based on the cost analysis, FHR has determined that the added capital of CCS for the new and modified heaters at the refinery would make the proposed project economically infeasible. In fact, the costs of a CCS system would be greater than 45% of the estimated $760 million capital cost of the project as a whole without CCS.

When performing an economic evaluation of available, demonstrated, and technically feasible control alternatives, the elimination of a control alternative on economic grounds typically involves the development of annualized capital and operating costs and the expression of those costs on the basis of dollars per ton of pollutant removed. That dollar per ton cost would then be compared to “the range of recent costs normally associated with BACT for the type of facility (or BACT control costs in general) for the pollutant.”[24] However, such a comparison is not possible for the new and modified heaters for CO_2e, because there is no range of recent costs associated with BACT due to the fact that CCS is not been found elsewhere to be available, demonstrated, or technically feasible for the source type here under review. EPA has recognized this in its PSD and Title V Permitting Guidance for Greenhouse Gases published in March, 2011, stating that “it may be appropriate in some cases to assess the cost-effectiveness of a control option in a less detailed quantitative (or even a qualitative) manner,” including whether the cost of CCS is “extraordinarily high and by itself would be considered cost prohibitive.” Consistent with this guidance, for this project FHR’s quantification of the extraordinarily high capital cost of CCS relative to the cost of the overall project is sufficient to demonstrate that CCS is not cost effective.

In addition to being unavailable, technically infeasible, and not cost-effective, the implementation of CCS would result in significant adverse collateral energy and environmental impacts. The increased energy consumption for the CCS system would completely negate any efficiency savings from implementing efficient design and operational practices for the heaters themselves. The energy burden for the steam boiler required for amine regeneration approaches the fuel consumption of the sources it would control. Furthermore, the addition of the 150# Steam Boiler would result in criteria pollutant emissions, and would create another source whose GHG emissions would need to be captured.

[24] EPA. “Draft New Source Review Workshop Manual” October, 1990. See p. B.45.

Emissions increases at the site associated with the theoretical application of CCS would result primarily from the additional 150# boiler that would be needed to provide the steam required for the amine capture unit. The estimated emissions based on the minimum heat input required to generate the needed steam are as follows:

Estimated Emissions from 150# Boiler		
Pollutant	Short-term Emission Rate (lb/hr)	Long-term Emission Rate (tons/yr)
SO2	4.70	2.06
NOx	3.49	11.46
PM	2.60	11.39
CO	2.53	11.10
VOC	1.88	8.24
CO2	40,800.00	178,700.00

The above estimates are pre-control and are based on a natural-gas fired unit with emissions factors equivalent to the proposed new Sat Gas No. 3 Hot Oil Heater.

In addition to the above on-site emissions, off-site emissions would occur from electrical consumption to provide approximately 13.3 MW (117,000 MWh/yr) of power that would be necessary to power the capture skids, regeneration skids, and the compression associated with CCS. Note that this does not include the electricity consumption at pipeline booster stations that would be required to transport CO_2 to a distant offsite location. Using the EPA's eGRID power profiler to calculate off-site emissions, estimated off-site emissions from power demands are approximately 45 tpy NO_X, 140 tpy SO_2, and 75,000 tpy CO_2.

Significant adverse impacts would also result from increased water consumption associated with CCS. The CO_2 capture skids (3 services) and the regeneration skid necessary for the theoretical application of CCS to the Project would all require cooling water to cool the process heater flue gas, to cool the lean MEA, and to cool the CO_2 between stages of compression. The total amount of additional circulating cooling water would be an estimated 18,600 GPM, with a new cooling water duty of approximately 170 MMBtu/hr. Assuming negligible drift and 6 cycles of operation, approximately 400 GPM of make-up water would be required, slightly less than a 10% increase in the fresh water demand for the West Refinery. Because Corpus Christi is in an area prone to drought, the additional water demand that would be associated with the application of CCS to the Project is not insubstantial.

Step 5: Select the BACT.

In the fifth step, the most effective control option, based on the impacts quantified in Step 4, is proposed as BACT for the emission unit under review. For both the Sat Gas No. 3 and CCR Hot Oil Heaters, FHR proposes use of the top and only remaining BACT option—the implementation of energy efficient design and operating practices. The implementation of a state-of-the-art, energy efficient design results in a heater design efficiency of 92% for the new Sat Gas No. 3 Hot Oil Heater and 91% for the CCR Hot Oil Heater, and energy efficient operating practices will minimize GHG emissions over time.

The proposed form of the limitations is summarized in the following table:

Category	Demonstration
Limitations	Greenhouse gas emissions limited to the following tons CO_2e per year on a 365-day rolling total: Sat Gas No. 3 Hot Oil Heater 236,242 tons CO_2e/365-days CCR Hot Oil Heater 63,193 tons CO_2e/365-days An effective means to demonstrate heater operating efficiency is to rely upon the stack exit temperature as a surrogate. Based upon the design of these heaters, maintaining the stack exit temperature below 350 degrees F on a 365-day rolling average basis, excluding periods of heater start-up, shutdown, and low firing rates (<60% of maximum design capacity), over the life of the equipment is indicative of a properly operated heater designed for 92% (Sat Gas No. 3 Hot Oil Heater)/91% (CCR Hot Oil Heater) efficiency.
	Limit excess O_2 in the Sat Gas No. 3 Hot Oil Heater and the CCR Hot Oil Heater exhaust to 4% or less on a 365-day rolling average basis, excluding periods of heater start-up, shutdown, and low firing rates (<60% of maximum design capacity). See Notes 1 and 4.
	Additional work practice standard: In accordance with 40 C.F.R. part 63, subpart DDDDD, conduct annual tune-up (which may include burner inspection and cleaning, flame inspection and optimization, air-to-fuel ratio, and CO optimization as required by subpart DDDDD).
Monitoring Requirements	Maintain compliance with 40 C.F.R. Part 98, Subpart C including flow monitoring of fuel usage and fuel gas analysis.
	Maintain a flue gas temperature monitor to continuously record flue gas exit temperature on each hot oil heater while the heaters are in service.
	Continuously monitor each heater's stack exit temperature. Stack exit temperatures recorded during periods of monitoring

Category	Demonstration
	instrumentation malfunction and maintenance shall be excluded from consideration provided monitoring operation downtime does not exceed 5% of any 365-day rolling period. Monitoring operation downtime in excess of 5% of any 365-day period shall be reported in the Quarterly Excess Emissions and CEMs Report. See Note 1.
Compliance Demonstration	Demonstrate compliance with the 365-day rolling total limitations by using Tier 3 or Tier 4 calculation methodologies, as described by 40 C.F.R. § 98.33, to calculate the CO_2 emissions and the appropriate methodologies as described by 40 C.F.R. § 98.33(c) to calculate the CH_4 and N_2O emissions. The emissions calculated with these methodologies will be converted from metric tons to short tons. See Note 1.
	Report, in its Quarterly Excess Emissions and CEMS Report, any exceedances of the rolling 365-day average of CO_2e emissions for the Sat Gas No. 3 Hot Oil Heater and CCR Hot Oil Heater. See Note 1.
	A stack exit temperature above 350 degrees F on a 24 hour average basis, excluding periods of heater start-up, shutdown, and low firing rates (<60% of maximum design capacity), is an excursion that requires corrective action. Upon detecting an excursion, restore operation of the heater to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing the period of any excursion and taking any necessary corrective actions to restore normal operation. Such actions may include heater adjustments or equipment maintenance. Excursions are events that require a response. Excursions shall not be considered out of compliance with the limit unless the stack gas exit temperature is above 350 degrees F on a 365-day rolling average basis, excluding periods of heater start-up, shutdown, and low firing rates (<60% of maximum design capacity). See Notes 1, 2 and 3.
	Report excursions and a summary of response actions in the Quarterly Excess Emissions and CEMS Report. See Note 1.
	Maintain records of flue gas temperature and annual heater tuning performed for compliance and may utilize normal business records for this purpose.

Note 1: This provision is included pursuant to a settlement agreement among FHR, Environmental Integrity Project, and University of Texas School of Law Environmental Clinic.

Note 2: The 24 hour average stack exit temperature for each heater shall be determined using the following formula:

24 hour Average Temperature = Sum of Valid Temperature Readings in a 24-hour Period / Quantity of Valid Temperature Readings in a 24-hour Period

Note 3: The 365-day rolling average stack exit temperature for each heater shall be determined using the following formula:

365 day Average Temperature = Sum of Valid Temperature Readings in a 365 day Period / Quantity of Valid Temperature Readings in a 365 day Period

Note 4: The 365-day rolling average stack exit temperature for each heater shall be determined using the following formula:

365 day Average Excess O_2 Level = Sum of Valid Excess O_2 Readings in a 365 day Period / Quantity of Valid Excess O_2 Readings in a 365 day Period

To achieve the proposed BACT emission limits, the heaters will be designed and operated to utilize a number of efficiency measures. The following summary table is being provided to describe with specificity the design and operating strategies proposed for each heater. These strategies are believed to be consistent with permits issued to date by EPA Region 6 and other state and federal permitting authorities, and are in-line with other pending applications that have been consulted in preparation of this analysis. See Appendix B for additional information.

Efficiency Technology	Description	Proposed?	Comments on Application
Reduce Energy Loss by Minimizing Excess O_2/Stack Flow	Install Energy Efficient Burners	Yes	Efficient burners will be selected that enable complete combustion (low CO) with low excess air and targeted NOx performance.
	Combustion Tuning & Optimization	Yes	This will be part of the heater startup with equipment vendors. Tuning to optimize burner performance will be incorporated into an annual procedure.
	Draft/Trim Instrumentation and Controls	Yes	Heaters will be equipped with instrumentation and controls to regulate and optimize excess O_2.
	Reduce Air Leakage	Yes	In addition to firebox O_2 instrumentation to monitor O_2 near the burners, the heaters will be equipped with stack O_2 instrumentation which will help to identify and minimize air leaks. The heaters will be subject to a preventive maintenance program as well as regular visual inspections.
Reduce Energy Loss by Minimizing Stack Temperature	Waste Heat Recovery (Economizer/Air Preheater)	Yes	The heaters will use air preheat to recover the energy in the flue gas to preheat combustion air. This will maximize energy efficiency by increasing the combustion air temperature while reducing the flue gas temperature. Further heat recovery through an

Efficiency Technology	Description	Proposed?	Comments on Application
			economizer is not feasible because the units are limited by a 50°F approach between flue gas operating and dew point temperature in order to prevent corrosion.
	Reduce Slagging and Fouling of Heat Transfer Surfaces	Yes	Natural gas and refinery fuel gas are low particulate/low fouling fuels that provide an inherently favorable design for heat exchange without steam-consuming soot blowers to keep transfer surfaces clean.
Reduce Conductive Heat Energy Loss	Insulation/Insulating Jackets	Yes	The heater designs will minimize heat losses through proper selection of refractory and insulation materials.

BACT for Equipment Leak Fugitives

GHG emissions from equipment leak fugitives are the result of potential leaks from piping fugitive components (valves, flanges, pumps, compressors, etc.) that will be added as a part of the proposed project. CH_4 is present in variable concentrations in refinery process streams, with highest concentrations in refinery fuel gas and natural gas. Because CH_4 is a GHG, the analysis focuses on mitigating CH_4 emissions.

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

In reviewing the resources outlined above, the following technologies were identified as potentially available for the equipment leak fugitives in this application:

Technology	Description	Availability
LDAR	LDAR includes requirements for Method 21 monitoring of equipment components (*e.g.*, valves, pumps, connectors, compressors, and agitators) for detection of leaks and subsequent repair, or attempt to repair, any components that have been determined to be leaking. Examples include: • TCEQ 28VHP program • 40 C.F.R. part 60, subpart GGGa	Available
Enhanced LDAR	Potential enhancements to the LDAR program may include: • Lower the definition of a “leaking” component threshold concentration • Increase the leak monitoring frequency which allows for early detection and repair of leaking components • Installation of components with “low leak” and/or “leakless” technologies in certain applications[25] • Flange/connector monitoring	Available
Optical Gas Imaging LDAR	Optical Gas Imaging consists of using an infrared camera to identify leaks, which would then be repaired as in a traditional LDAR program.	Available

As shown in the table above, each of these technologies is considered available, and will be evaluated in Step 2.

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

The second step requires the evaluation of the technical feasibility of each control option identified in Step 1 with respect to source-specific factors. Technologies that are determined to

[25] Pursuant to a Consent Decree between EPA and FHR, FHR has agreed to the following: “By December 31, 2001, Koch shall have developed standards for new equipment (*i.e.,* pumps, relief valves, sample connections, other valves) it is installing to minimize potential leaks. Koch will also make use of improved equipment, such as “leakless” valves for chronic leakers, where available, technically feasible, and economically reasonable.”

be infeasible are eliminated from further consideration. Based on the options carried forward from Step 1, the following table summarizes technical feasibility.

Technology	Description	Feasibility
LDAR	LDAR includes requirements for Method 21 monitoring of equipment components (*e.g.*, valves, pumps, connectors, compressors, and agitators) for detection of leaks and subsequent repair, or attempt to repair, any components that have been determined to be leaking.	Technically Feasible
Enhanced LDAR	Potential enhancements to the LDAR program may include: • Lower the definition of a "leaking" component threshold concentration • Increase the leak monitoring frequency which allows for early detection and repair of leaking components • Installation of components with "low leak" and/or "leakless" technologies in certain applications • Flange/connector monitoring	Technically Feasible
Optical Gas Imaging LDAR	Optical Gas Imaging consists of using an infrared camera to identify leaks, which would then be repaired as in a traditional LDAR program.	Technically Feasible

As shown in the table above, each of these technologies is considered technically feasible, and will be evaluated in Step 3.

<u>Step 3: Rank remaining control technologies.</u>

As part of the third step, all remaining control technologies not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness, with the most effective control alternative at the top. In the case of the competing LDAR programs, the most effective control measures are fundamentally a matter of leak detection threshold. As such, the ranking for these technologies is as follows:

1. Enhanced LDAR – installation of "low leak" and/or "leakless" components (designed to be less than 100 ppmv per Method 21)
2. LDAR - leak rates are generally based on 500 ppmv
3. Optical Gas Imaging LDAR – camera leak detection level is generally no less than 500 ppmv, typically significantly greater.

<u>Step 4: Evaluate most effective controls and document results.</u>

Energy, environmental, and economic impacts are considered for each of the control options during Step 4 only if the most effective control option is not proposed as BACT: "However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top and review for collateral environmental impacts." [26]

FHR is proposing to implement enhanced LDAR practices as BACT. There are no expected significant adverse collateral energy, environmental, or economic impacts as a result of the enhanced LDAR measures proposed as BACT. In this case, the economic impact is limited since most streams containing methane are also subject to monitoring for VOCs.

Step 5: Select the BACT.

In the fifth step, the most effective control option, based on the impacts quantified in Step 4, is proposed as BACT for the pollutant and emission unit under review. For the equipment leak fugitives associated with this project, FHR proposes use of the top option as BACT, which is to implement an enhanced LDAR program, which will include monitoring for CH_4 in addition to VOCs.

FHR is proposing adherence to enhanced LDAR standards as BACT. FHR will operate in compliance with the TCEQ 28VHP program with annual flange/connector monitoring, the requirements in 40 C.F.R. part 60, subpart GGGa as specified in the facility's Title V permit, and the LDAR equipment conditions established by the Consent Decree referenced above. Specifically, in accordance with the Consent Decree, FHR will implement "low leaking" technology for all new non-specialized globe and gate valves. These valves are required to meet <100 ppm leakage as purchased.

In the NSR Workshop manual, EPA writes that ""…if the reviewing authority determines that there is no economically reasonable or technologically feasible way to accurately measure the emissions, and hence to impose an enforceable emissions standard, it may require the source to use design, alternative equipment, work practices or operational standards to reduce emissions of the pollutant to the maximum extent."[27] Because of the very low GHG emissions resulting from equipment leaks and due to the fact that it is impractical to measure the amount of GHG emitted from leaking components, no specific emission limit is being proposed for GHG emissions resulting from equipment leaks. Compliance with the enhanced LDAR standards discussed above is proposed as BACT for GHG emissions resulting from equipment leaks. The proposed form of the limitations is summarized in the following table:

[26] EPA NSR Manual at B.8.
[27] EPA NSR Workshop Manual, Page B.2

Category	Demonstration
Limitations	No numeric emission limitation. Rather, work practice standard is proposed under monitoring and compliance demonstration below. It is not feasible to convert the monitoring results to a numerical limit because the monitoring results will not indicate the amount that is CH_4 versus VOCs generally.
Monitoring Requirements	Conduct LDAR monitoring per the TCEQ 28VHP program (as listed on the following pages), 40 C.F.R. part 60, subpart GGGa, and consent decree requirements.
Compliance Demonstration	Maintain records of LDAR monitoring per the TCEQ 28VHP program, NSPS GGGa, and consent decree requirements.

The referenced 28VHP program requires the following:

<u>TCEQ 28VHP Fugitive Monitoring Requirements – Permit 8803A, Special Condition 17</u>

17. Piping, Valves, Connectors, Pumps, and Compressors in VOC Service - 28VHP
Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment: (01/12)

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list of one of the methods described below to be made readily available upon request.

The exempted components may be identified by one or more of the following methods:
(1) piping and instrumentation diagram (PID); or
(2) a written or electronic database or electronic file.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Difficult-to-monitor and unsafe-to-monitor valves, as defined by 30 TAC Chapter 115, shall be identified in a list to be made readily available upon request. The difficult-to-monitor and unsafe-to-monitor valves may be identified by one or more of the methods described in subparagraph A above. In an unsafe-to-monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times. A difficult-to-monitor component for which quarterly monitoring is specified may instead be monitored annually.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than normal operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through. Any leaks discovered through AVO inspection shall be tagged and/or replaced or repaired.

Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the removal of a component for repair or replacement results in an open-ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period:
The line or valve must have a cap, blind flange, plug, or second valve installed; or the permit holder shall verify that there is no leakage from the open-ended line or valve. The open-ended line or valve shall be monitored on a weekly basis in accordance with the applicable NSR permit condition for fugitive emission monitoring except that a leak is defined as any VOC reading greater than background. Leaks must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve. The results of this weekly check and any corrective actions taken shall be recorded.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

A check of the reading of the pressure-sensing device to verify disc integrity shall be performed weekly and recorded in the unit log or equivalent. Pressure-sensing devices that are continuously monitored with alarms are exempt from recordkeeping requirements specified in this paragraph.

The gas analyzer shall conform to requirements listed in Method 21 of 40 C.F.R. Part 60, Appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section 8 of Method 21. If a mixture of VOCs is being monitored, the response factor shall be calculated for the average composition of the process fluid. A calculated average is not required when all of the components in the mixture have a response factor less than 10 using methane. If a response factor less than 10 cannot be achieved using methane, then the instrument may be calibrated with of the VOCs to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOCs to be measured.

Replacements for leaking components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump and compressor seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump and compressor seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak shall be made within 5 days. Records of the first attempt to repair shall be maintained.

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 15 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown as calculated in accordance with 30 TAC 115.782 (c)(1)(B)(i)(I), the TCEQ Regional Manager and any local programs shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

J. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings. Records of physical inspections shall be noted in the operator's log or equivalent.

K. Alternative monitoring frequency schedules of 30 TAC §§ 115.352-115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 C.F.R. Part 63, Subpart H, may be used in lieu of Items F through G of this condition.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable NSPS, or an applicable NESHAPS and does not constitute approval of alternative standards for these regulations.

For purposes of establishing the final ER caps for this flexible permit, implementation of the 28 VHP LDAR program and the appropriate reduction credits were utilized. If any other LDAR program is used for a set of components subject to this permit, the fugitive emissions for all components shall be calculated using the appropriate reduction credits for the LDAR program actually used to monitor each component. For components monitored under an LDAR program other than 28 VHP, the net ERs from these components must be equivalent or less than those obtained if 28 VHP were in place.
The holder of this permit shall maintain a record of each LDAR program utilized, and the unit to which that program is applied. This information shall be made available to representatives of the TCEQ upon request.

M. As an alternative to comparing the daily emission rate of the components on the delay of repair (DOR) list to the total emissions from a unit shutdown per the requirements of Special Condition No. 17, Subparagraph I, the cumulative hourly emission rate of all components on the DOR list may be compared to ten percent of the fugitive short term allowable on the Maximum Allowable Emission Rate Table in order to determine if the TCEQ Regional Director and any local program is to be notified. In addition, the hourly emission rates of each specific compound on the DOR list must be less than ten percent of the speciated hourly fugitive emission rate of the same compound. (07/11)

N. Relief valves with rupture discs are exempt from weekly visual monitoring if they are monitored quarterly via an approved gas analyzer, or if the relief valves relieve to a control device. (11/11)

BACT for Cooling Tower

GHG emissions from the Mid Plant Cooling Tower No. 2 are the result of potential CH_4 leaks from heat exchangers into cooling water. Any CH_4 contained in the cooling water is ultimately stripped and emitted from the cooling tower. Because CH_4 is a GHG, the analysis focuses on mitigating CH_4 emissions from leaks into cooling water.

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

In reviewing the resources outlined above, the following technologies were identified as potentially available for the Mid Plant Cooling Tower No. 2:

Technology	Description	Availability
Cooling Tower Monitoring and Repair	This technology consists of monthly monitoring of the cooling water to detect leaks, and subsequent repair of any exchangers that that have been determined to be leaking. Examples include the present permit conditions and consent decree provisions for controlling VOC emissions from cooling towers at the site.	Available

As shown in the table above, the only technology identified is considered available, and will be evaluated in Step 2.

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

The second step requires the evaluation of the technical feasibility of each control option identified in Step 1 with respect to source-specific factors. Technologies that are determined to be infeasible are eliminated from further consideration. Based on the options carried forward from Step 1, the following table summarizes technical feasibility.

Technology	Description	Feasibility
Cooling Tower Monitoring and Repair	This technology consists of monthly monitoring of the cooling water to detect leaks, and subsequent repair of any exchangers that that have been determined to be leaking.	Technically Feasible

As shown in the table above, the only technology identified is considered technically feasible, and will be evaluated in Step 3.

<u>Step 3: Rank remaining control technologies.</u>

As part of the third step, all remaining control technologies not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. In this case, implementation of cooling tower monitoring and repair is ranked at the top of the list as the only technically feasible control option available for the new cooling tower.

Step 4: Evaluate most effective controls and document results.

Energy, environmental, and economic impacts are considered for each of the control options during Step 4 only if the most effective control option is not proposed as BACT: “However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top and review for collateral environmental impacts.” EPA NSR Manual at B.8.

FHR is proposing to implement cooling tower monitoring and repair as BACT. This is the top control alternative that has been determined to be available and technically feasible. There are no expected significant adverse collateral energy, environmental, or economic impacts as a result of the cooling tower monitoring and repair measures proposed as BACT.

Step 5: Select the BACT.

In the fifth step, the most effective control option, based on the impacts quantified in Step 4, is proposed as BACT for the pollutant and emission unit under review. For the Mid Plant Cooling Tower No. 2, FHR proposes use of the top option as BACT, which is to implement a cooling tower monitoring and repair program.

In the NSR Workshop manual, EPA writes that “…if the reviewing authority determines that there is no economically reasonable or technologically feasible way to accurately measure the emissions, and hence to impose an enforceable emissions standard, it may require the source to use design, alternative equipment, work practices or operational standards to reduce emissions of the pollutant to the maximum extent.”[28]

The proposed form of the limitations is summarized in the following table:

[28] EPA NSR Workshop Manual, Page B.2

Category	Demonstration
Limitations	No numeric emission limitation. Rather, work practice standard is proposed under monitoring and compliance demonstration below. It is not feasible to convert the monitored concentrations to a numerical emission limit because the monitoring result will not indicate the amount that is CH_4 versus VOCs generally.
Monitoring Requirements	Implement a cooling tower monitoring program on a monthly basis consistent with the TCEQ Appendix P Air Stripping method, which is referenced in 40 C.F.R. Part 63, subpart CC. The leak thresholds and repair timelines will be as designated in TCEQ Permit 8803A and the effective consent decree.
Compliance Demonstration	Maintain records of cooling tower monitoring and corrective actions as required by special provisions in the state NSR permit for VOCs. Methane will be treated as a VOC for the purposes of compliance with those provisions.

The referenced permit condition and consent decree read as follows:

Permit 8803A, Special Condition 10, Cooling Tower Process Requirements

10. Cooling water towers shall be monitored in accordance with the provisions of Paragraph 69(b) of the Consent Decree between EPA and Flint Hills Resources, LP, (U.S. et al. V. Koch Petroleum Group, L.P., Civil Action No. 00-2756 (PAM/SRN), U.S. District Court for District of Minnesota, April 25, 2001) as amended, as it pertains to the Corpus Christi West Refinery. Confirmed leaks shall be repaired and corrections shall be confirmed within the timelines prescribed in Paragraph 69(b) of said Consent Decree. The results of the monitoring and maintenance efforts shall be recorded, and such records shall be maintained for a period of five years. The records shall be made available to the TCEQ Executive Director upon request.

The following cooling towers are subject to this monitoring condition:

EPN	Name
F-S-8	CCR Cooling Tower
F-S-201	Mid-Plant Cooling Tower
F-S-1	Main Cooling Tower
F-S-2	Ultraformer Cooling Tower
F-S-4	Rex Cooling Tower
F-S-5	No. 3 Paraxylene Cooling Tower
F-S-6	Styrene Cooling Tower

EPN	Name
F-S-7	East Crude Cooling Tower
F-S-101	West Crude Cooling Tower
F-S-10	Sulfur Plant Cooling Tower

Four months prior to the completion of the consent decree requirements, if the permit holder is no longer required by EPA to comply with Paragraph 69(b), the permit holder shall apply for a permit alteration or an amendment to revise this cooling tower condition. **(08/10)**

Consent Decree:

b) Leaks into Cooling Towers. Effective beginning January 1, 2005, FHR shall follow the procedures outlined in this subparagraph (b) for addressing any benzene associated with leaks of process fluids into non-contact, recirculating cooling tower systems (herein referred to as cooling tower systems) for the purpose of compliance with the Benzene Waste NESHAP. Consequently, the “point of waste generation” under 40 C.F.R. Sec. 61.341 of any of the FHR cooling tower systems affected by the Consent Decree shall be considered to be the point where the water is blown down to a sewer drain or other wastewater conveyance. For the avoidance of doubt, this means that so long as the facility is complying with the monitoring and repair requirements of subparagraph (b), cooling tower water combined with process fluids that have leaked into the cooling tower system shall not be considered a waste stream until after such water has been blown down to a wastewater conveyance.

(i) Applicability. The monitoring and sampling requirements of this subparagraph (b) shall apply to all cooling tower systems at the Corpus Christi East, Corpus Christi West, and Pine Bend facilities that have the potential to come in contact with process fluids that have a benzene content of 0.1 wt% or greater. The potential to come in contact is present because of the possibility of process leaks even if the system is considered non- contact.

(ii) Daily Parametric Monitoring. FHR shall perform at least one of the following types of parametric monitoring daily for each of the affected cooling tower systems:(A) Visual or olfactory observations for hydrocarbons; (B) Chemical use mass balance; (C) Microbiological growth detection; or (D) pH monitoring. If the results of such monitoring, alone or in conjunction with other process knowledge, indicate the likely presence of benzene in excess of 1 ppmw in the cooling water, FHR shall obtain three representative samples of water from a cooling tower riser located at the potentially-impacted cooling tower(s) within 24 hours, and shall transmit the samples within 72 hours by next day delivery to an external lab for analysis utilizing one of the test methods in 40 C.F.R. Sec. 61.355(c)(3)(iv).

(iii) Detection of Benzene in Cooling Water. Once FHR has detected the presence of benzene greater than 1 ppmw in the cooling water prior to entering a cooling tower riser as provided in subparagraph (b)(ii), additional water samples required by subparagraph (b)(ii) are not needed until such time after the source of the benzene has been repaired, even though subsequent parametric monitoring (e.g., pH monitoring) conducted up to and until the repair continues to indicate the presence of benzene. FHR shall collect and analyze additional water samples in accordance with subparagraph (b)(ii) if parametric monitoring or other process knowledge indicates that a new leak has likely occurred.

(iv) Periodic Cooling Tower Sampling at Pine Bend Refinery. FHR Pine Bend shall obtain three representative samples of the cooling water from each applicable cooling tower once per calendar month and will transmit such samples within 24 hours by next day delivery to the external lab for analysis using one of the test methods in 40 C.F.R. Sec. 61.355(c)(3)(iv).

(v) Cooling Tower Sampling at Corpus Christi East and West Refinery. At the Corpus Christi refineries, FHR shall monitor the exhaust of each of its applicable cooling water strippers for VOC content once per calendar month. If a VOC reading is greater than 5 ppmv, and/or any other process knowledge indicates the likely presence of benzene in excess of 1 ppmw in the cooling water, FHR shall obtain three representative samples of the water entering the potentially impacted cooling tower and will transmit such samples within 24 hours by next day delivery to the external lab for analysis using one of the test methods in 40 C.F.R. Sec. 61.355(c)(3)(iv). Once a leak has been identified and until it has been repaired, subsequent VOC monitoring that continues to indicate the same leak does not give rise to a requirement to obtain additional water samples, except as needed by FHR to determine if the leak has changed or unless VOC monitoring or process knowledge indicates that a new leak likely has occurred.

(vi) Repair Deadline for Confirmed Leak. If FHR determines, through the water sampling and benzene analyses referenced in subparagraphs (ii), (iii), (iv), or (v) that a leak from process equipment has caused the benzene concentration in the cooling water prior to entering the cooling towers to exceed 1 ppmw, FHR shall repair the leak within 45 days after the date that FHR identifies the equipment that is leaking. FHR shall make all reasonable efforts to identify the leaking equipment as expeditiously as possible, but in no case shall the identification period exceed 30 days from the date the laboratory analysis indicates that there is the presence of benzene in excess of 1 ppmw in the cooling tower system. The period to identify a leak may be extended beyond 30 days upon the consent of EPA.

(vii) Exclusions to the Repair Deadline. This 45-day deadline to repair is not applicable if one or more of the following criteria is met:

(A). The equipment that is causing the leak is isolated from the process as soon as practical, but no longer than 45 days from when FHR identified the leaking equipment;

(B). The necessary parts are not reasonably available (in which case, the repair must be completed within 120 days of the date the leaking equipment is identified);

(C). Shutdown of the affected unit is already planned to occur within 60 days from the date the leaking equipment is identified;
(D). Shutdown for repair would cause greater emissions than the potential emissions that would result from a delay of repair (in which case FHR must make that calculation prior to relying on this exemption);
(E). The process fluid has been prevented from leaking into the cooling tower system via a process or system change; or
(F). Subsequent samples (utilizing 2 representative samples) confirm that the concentration of benzene in the cooling water prior to the cooling tower is less than 1 ppmw.

(viii) Confirmation of Repair. Once FHR has identified and corrected a leak pursuant to (vi) above, it shall conduct water sampling within 14 days of the repair or startup, whichever is later, to confirm that the benzene concentration in the cooling water prior to the cooling towers is less than 1 ppmw. The confirmation sampling may occur later if more time is needed to obtain a reliable sample due to water quality problems. At no time shall the confirmation sampling exceed 30 days after the repair or startup. If the confirmation sampling demonstrates that there is still a leak in the cooling tower system above 1 ppmw, then a new 45-day repair deadline shall commence on the date of such confirmation.

BACT for Maintenance, Start-up, and Shutdown Emissions

GHG emissions from MSS emissions are the result of maintaining new process vessels and other new equipment. The emissions are dominated by CO_2 emissions from degassing to a control device for VOC and GHG control. In addition, CH_4 and N_2O are present in substantially smaller amounts. Because emissions are predominantly CO_2, the analysis focuses on mitigating CO_2 emissions, which will result in a corresponding reduction in other GHGs. Because of the technical and economic difficulties in applying a measurement methodology to these sources, the BACT limit will be expressed as a work practice standard.

Step 1: Identify all available control technologies.

In reviewing the resources outlined above, the following technology was identified as potentially available for the MSS activities that are in part associated with the project:

Technology	Description	Availability
Minimize degassing emissions through good operational practices	Minimize degassing emissions by first pumping liquids to recovery, depressuring and purging to flare or flare gas recovery unit, and opening equipment to atmosphere only when the methane or VOC concentration is below 10,000 ppmv where practical. Maintain good combustion practices for portable thermal control devices for tank degassing.	Available

As shown in the table above, minimizing degassing emissions through good operational practices is considered available.

Step 2: Eliminate technically infeasible options.

The second step requires the evaluation of the technical feasibility of each control option identified in Step 1 with respect to source-specific factors. Technologies that are determined to be infeasible are eliminated from further consideration. Based on the options carried forward from Step 1, the following table summarizes technical feasibility.

Technology	Description	Feasibility
Minimize degassing emissions through good operational practices	Minimize degassing emissions by first pumping liquids to recovery, depressuring and purging to flare or flare gas recovery unit, and opening equipment to atmosphere only when the methane or VOC concentration is below 10,000 ppmv where practical. Maintain good combustion practices for portable thermal control devices for tank degassing.	Technically Feasible

As shown in the table above, minimizing degassing emissions through good operational practices is considered technically feasible.

Step 3: Rank remaining control technologies.

As part of the third step, all remaining control technologies not eliminated in Step 2 are ranked and then listed in order of overall control effectiveness for the pollutant under review, with the most effective control alternative at the top. In this case, minimizing degassing emissions through good operational practices is ranked at the top of the list as the only available and technically feasible control option available for MSS activities, with the potential for reducing GHG emissions by more than an estimated 90% in total.

Step 4: Evaluate most effective controls and document results.

Energy, environmental, and economic impacts are considered for each of the control options during Step 4 only if the most effective control option is not proposed as BACT: "However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top and review for collateral environmental impacts." (As shown in the EPA NSR Manual, page B.8.)

FHR is proposing to minimize degassing emissions through good operational practices as BACT. This is the only control alternative that has been determined to be available and technically feasible. There are no expected significant adverse collateral energy, environmental, or economic impacts as a result of this control alternative proposed as BACT.

Step 5: Select the BACT.

In the fifth step, the most effective control option, based on the impacts quantified in Step 4, is proposed as BACT for the pollutant and emission unit under review. For MSS emissions, FHR proposes use of the only option as BACT, which is to minimize degassing emissions through good operational practices.

In the NSR Workshop manual, EPA writes that "…if the reviewing authority determines that there is no economically reasonable or technologically feasible way to accurately measure the emissions, and hence to impose an enforceable emissions standard, it may require the source to use design, alternative equipment, work practices or operational standards to reduce emissions of the pollutant to the maximum extent."[29]

[29] EPA NSR Workshop Manual, Page B.2

The proposed form of the emission limitations is summarized in the following table:

Category	Demonstration
Limitations	No numeric emission limitation. Work practice standard is proposed under monitoring and compliance demonstration below.
Monitoring Requirements	Implement a recordkeeping system consistent with special provisions in the state NSR permit for VOCs listed in Appendix C.
Compliance Demonstration	Maintain records of MSS activities as required by special provisions in the state NSR permit for VOCs listed in Appendix C.

Section 6.0

MONITORING

GHG emissions will be monitored according to 40 C.F.R. part 98 (Mandatory Greenhouse Gas Reporting) as shown in the table provided in this section.

FIN	EPN	Description	PSD Source Type	Monitoring Method
SATGASHTR	SATGASHTR	Sat Gas #3 Hot Oil Heater	New	Maintain compliance with 40 C.F.R. Part 98, Subpart C including flow monitoring of fuel usage and fuel gas analysis. Maintain a flue gas temperature monitor to continuously record flue gas exit temperature while the heater is in service.
39BA3901	39BA3901	CCR Hot Oil Heater	Modified	Maintain compliance with 40 C.F.R. Part 98, Subpart C including flow monitoring of fuel usage and fuel gas analysis. Maintain a flue gas temperature monitor to continuously record flue gas exit temperature while the heater is in service.
F-SATGAS3	F-SATGAS3	New Sat Gas 3 Unit Fugitives	New	Conduct LDAR monitoring per the TCEQ 28VHP program (as listed on the following pages), 40 C.F.R. part 60, subpart GGGa, and consent decree requirements.
14-UDEX	F-14-UDEX	UDEX Fugitives	New	Conduct LDAR monitoring per the TCEQ 28VHP program (as listed on the following pages), 40 C.F.R. part 60, subpart GGGa, and consent decree requirements.
37	F-37	DHT Fugitives	New	Conduct LDAR monitoring per the TCEQ 28VHP program (as listed on the following pages), 40 C.F.R. part 60, subpart GGGa, and consent decree requirements.
39	F-39	NHT/CCR Fugitives	New	Conduct LDAR monitoring per the TCEQ 28VHP program (as listed on the following pages), 40 C.F.R. part 60, subpart GGGa, and consent decree requirements.

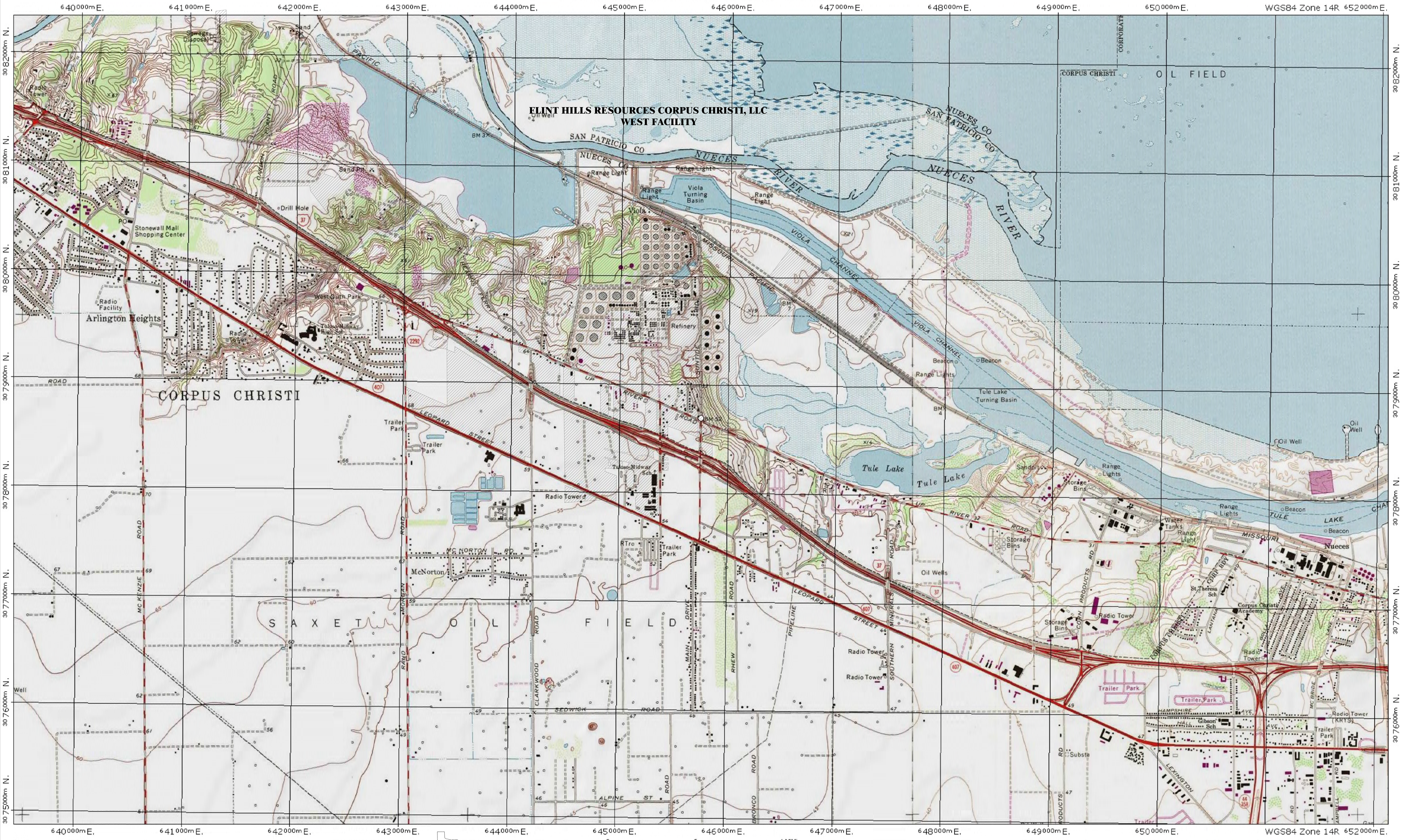
FIN	EPN	Description	PSD Source Type	Monitoring Method
40	F-40	West Crude Fugitives	New	Conduct LDAR monitoring per the TCEQ 28VHP program (as listed on the following pages), 40 C.F.R. part 60, subpart GGGa, and consent decree requirements.
42	F-42	Mid Crude Fugitives	New	Conduct LDAR monitoring per the TCEQ 28VHP program (as listed on the following pages), 40 C.F.R. part 60, subpart GGGa, and consent decree requirements.
P-GB	F-GB	Gasoline Blender Fugitives	New	Conduct LDAR monitoring per the TCEQ 28VHP program (as listed on the following pages), 40 C.F.R. part 60, subpart GGGa, and consent decree requirements.
P-VOC	F-TK-VOC	VOC Tank/Loading Fugitives	New	Conduct LDAR monitoring per the TCEQ 28VHP program (as listed on the following pages), 40 C.F.R. part 60, subpart GGGa, and consent decree requirements.
44EF1	F-S-201	Mid-Plant Cooling Tower	Modified	Implement a cooling tower monitoring program on a monthly basis consistent with the TCEQ Appendix P Air Stripping method, which is also referenced in 40 C.F.R. part 63, subpart CC. The leak thresholds and repair timelines will be as designated in TCEQ Permit 8803A and the effective consent decree.
44EF2	F-S-202	Mid-Plant Cooling Tower No. 2	New	Implement a cooling tower monitoring program on a monthly basis consistent with the TCEQ Appendix P Air Stripping method, which is also referenced in 40 C.F.R. part 63, subpart CC. The leak thresholds and repair timelines will be as designated in TCEQ Permit 8803A and the effective consent decree.

FIN	EPN	Description	PSD Source Type	Monitoring Method
MSSFUGS-DC	MSSFUGS-DC	Miscellaneous Fugitives from MSS Activities from Domestic Crude Project	New	Implement a recordkeeping system consistent with special provisions in the state NSR permit for VOCs.

Section 7.0

AREA MAP AND PLOT PLAN

645749mE 3078679mN Zone 14R WGS84 03/09/06 "Annaville, TX"



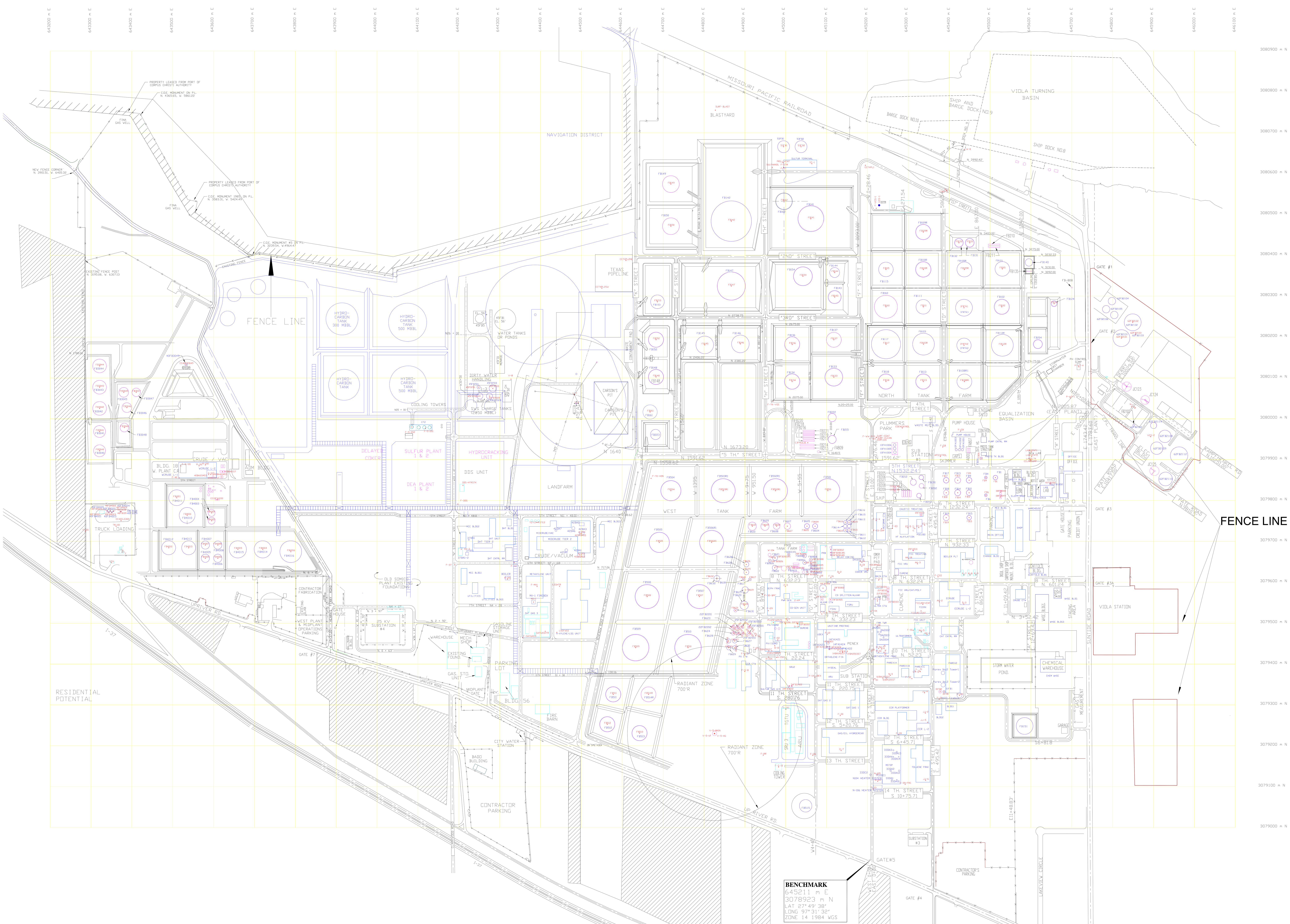
TN MN 5½°

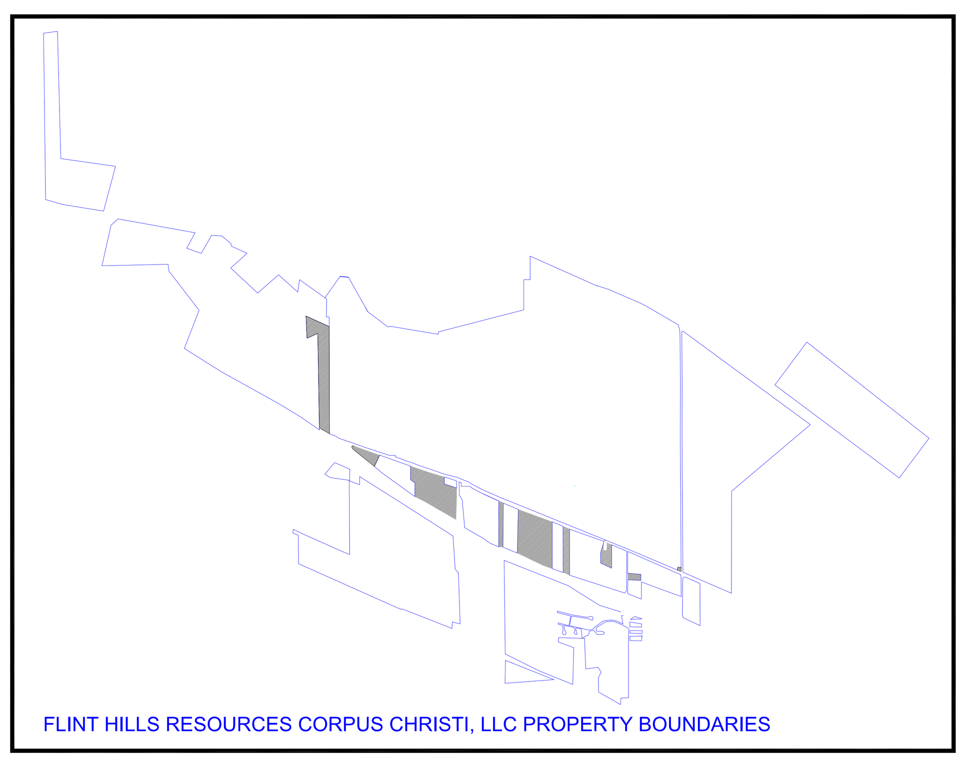
WAID ENVIRONMENTAL

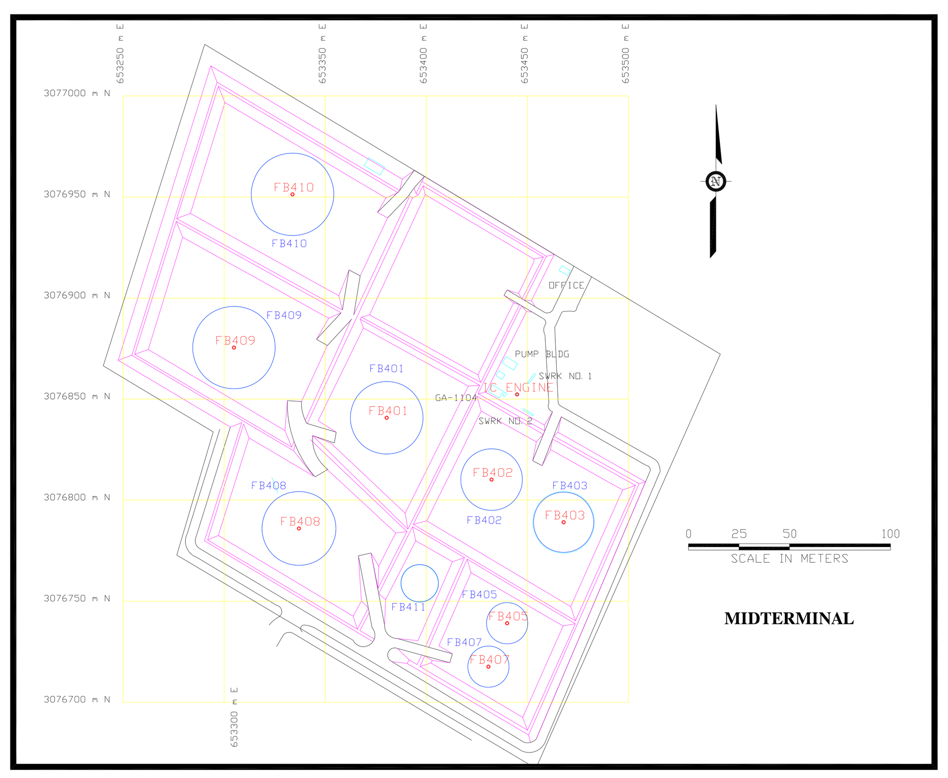
FLINT HILLS\8409\83QUADAREA

0 .5 1 MILE
0 1000 FEET 0 500 1000 METERS

Map created with TOPO!® ©2003 National Geographic (www.nationalgeographic.com/topo)







WAID ENVIRONMENTAL

FLINT HILLS RESOURCES CORPUS CHRISTI, LLC

CORPUS CHRISTI WEST REFINERY

Drawn By	Start Date	Rev. Date	DWG Name	Rev. No.
ERK/DWW	10/11/90	1/31/14	WESTBASE	271

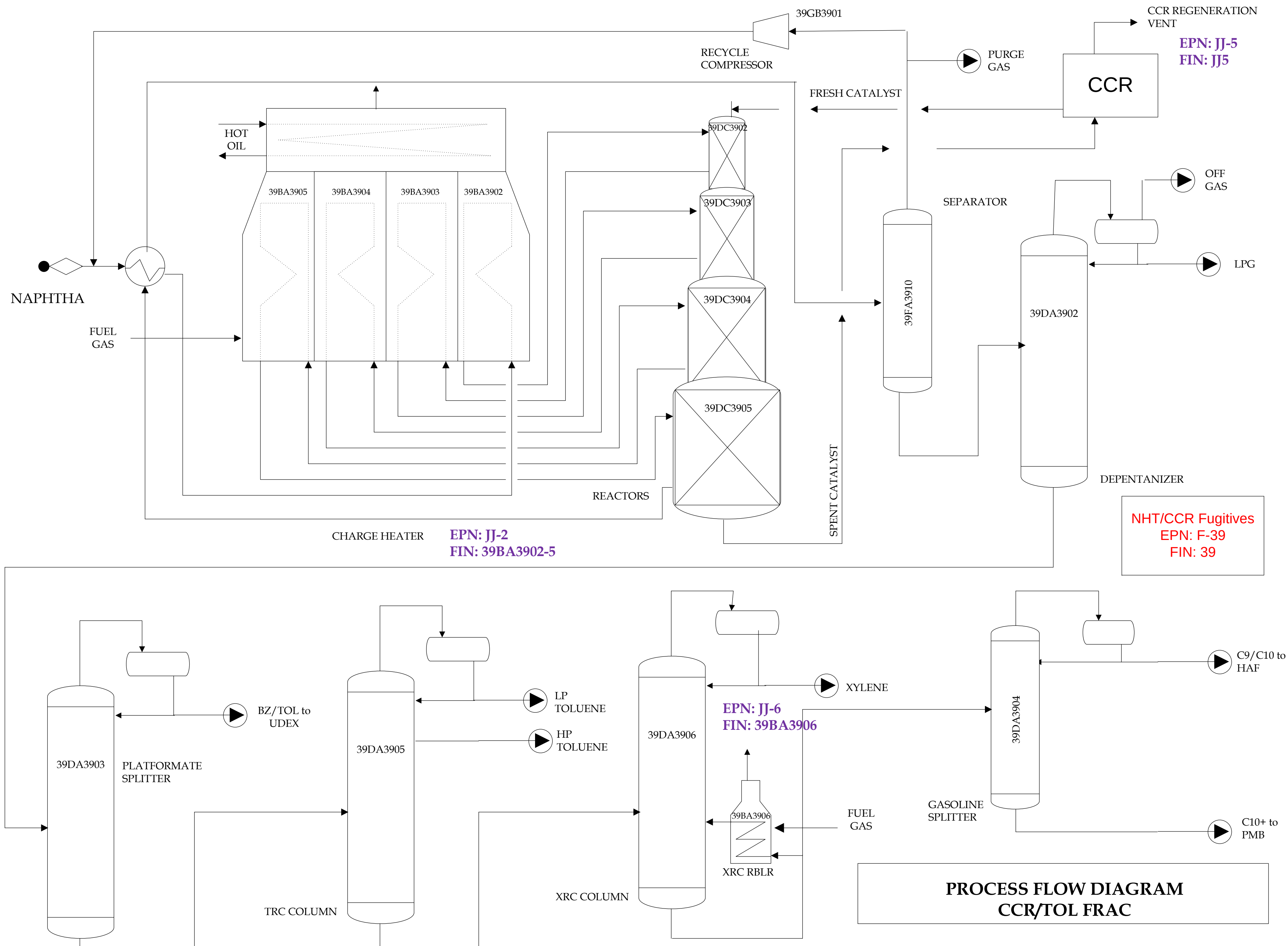
H:\CLIENTS\FLINTHILLSWEST\KRW00218\ACAD

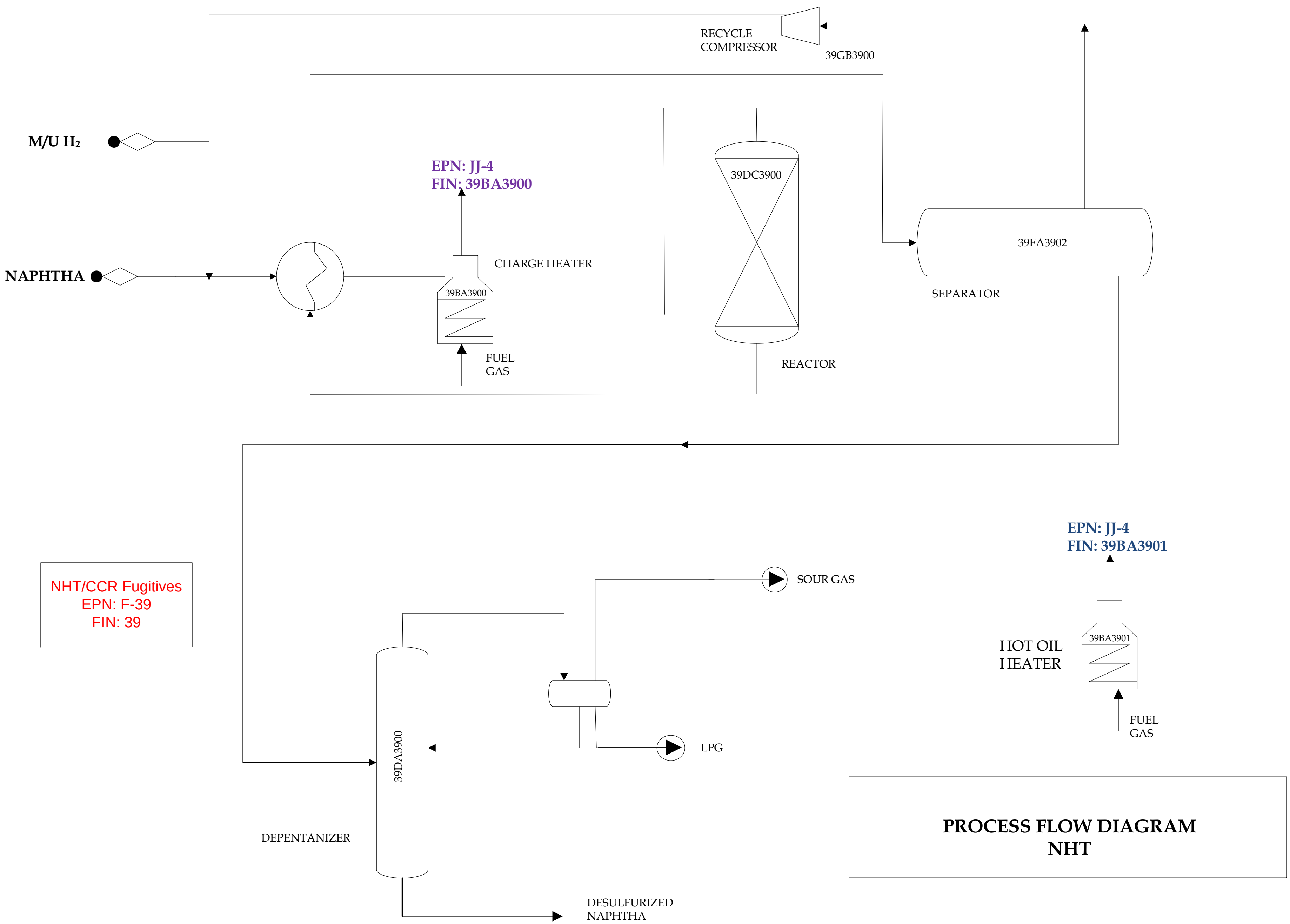
Section 8.0

PROCESS FLOW DIAGRAM

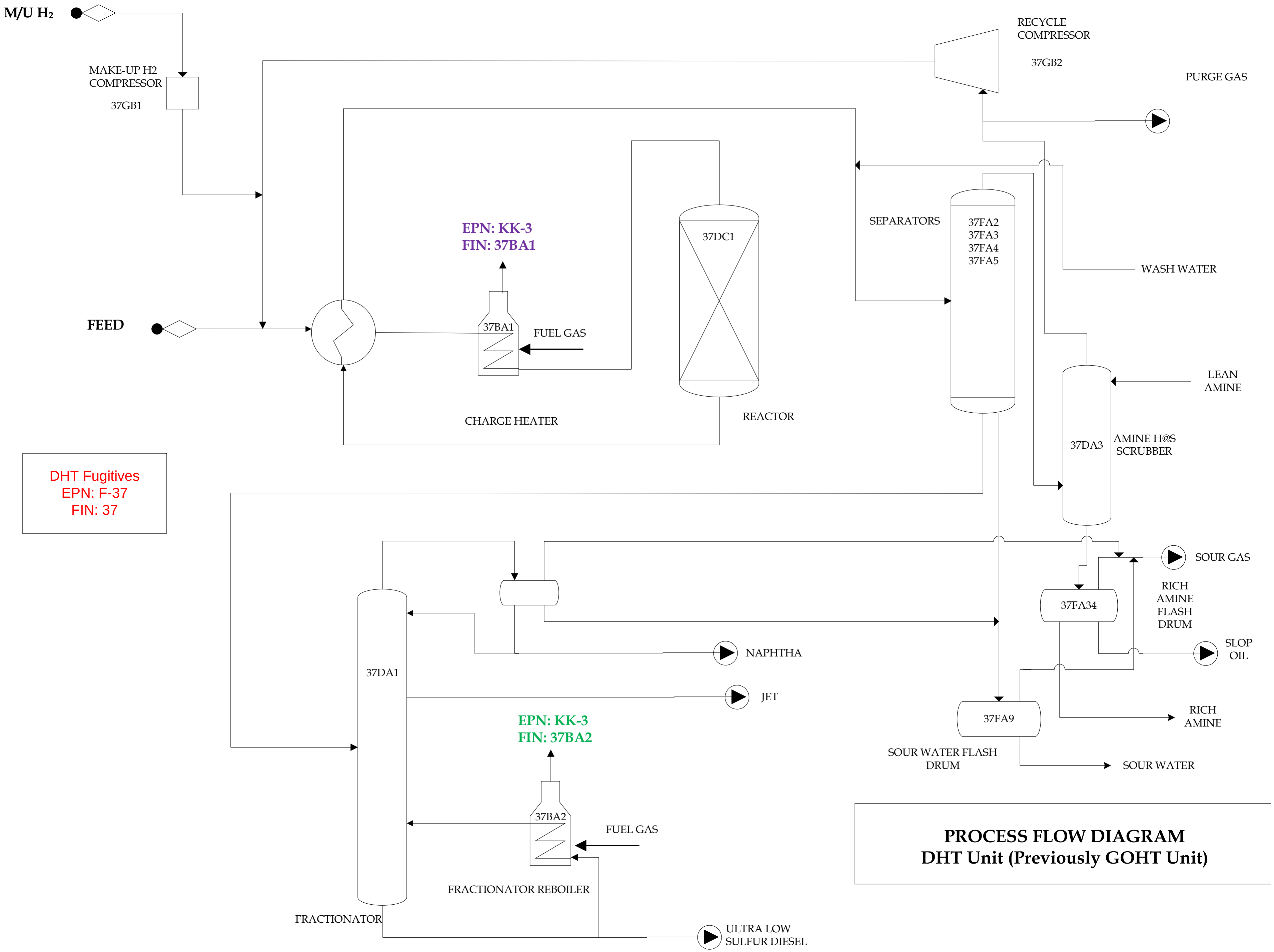
Process flow diagrams showing refinery operations are provided in this section. New emission units, modified emission units, and emission units affected upstream or downstream are noted on the process flow diagrams according to the following colors:

Color	Description
Red	New Emission Units
Blue	Modified Emission Units
Green	Affected Emission Units Upstream/Downstream

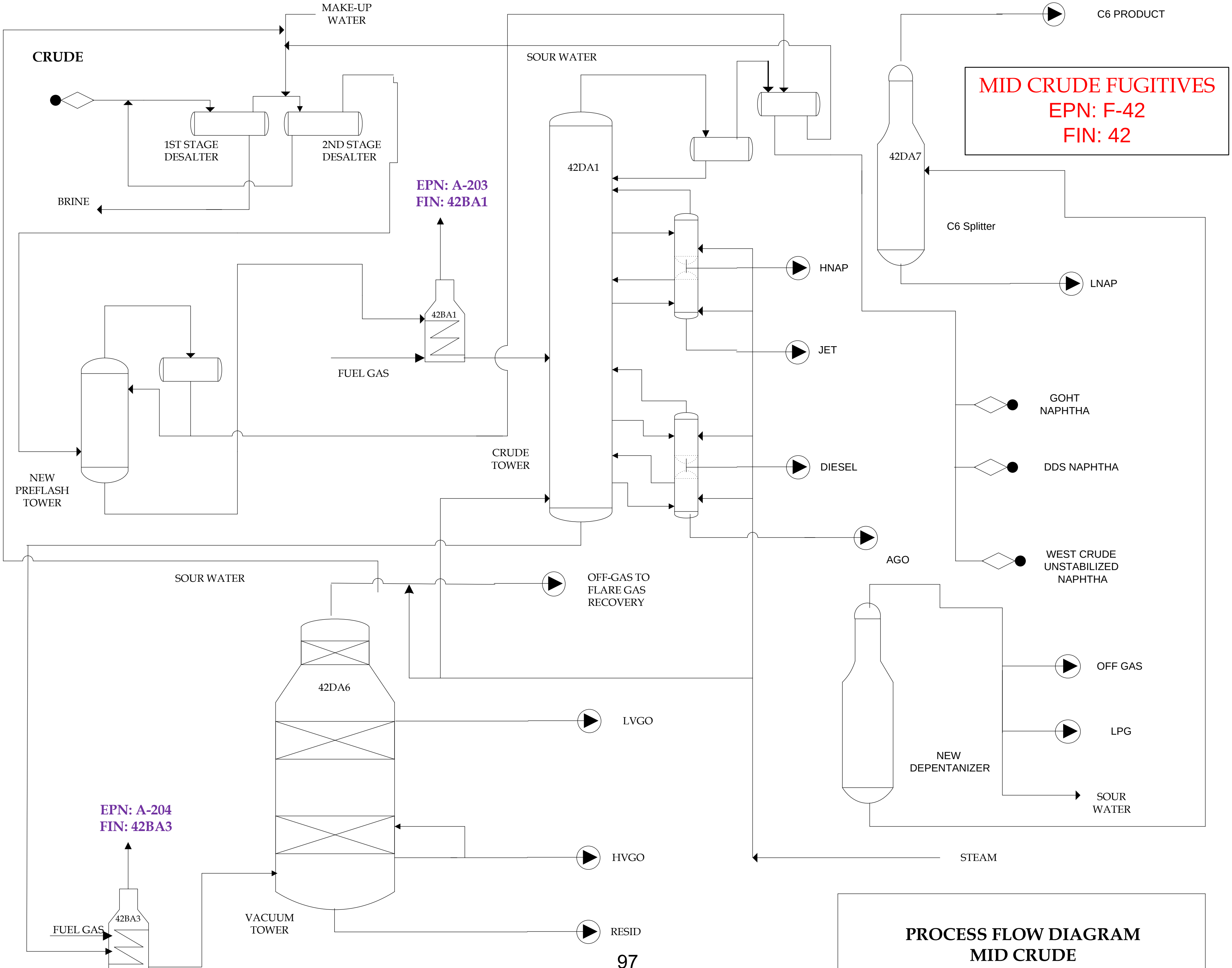

39GB3901
RECYCLE COMPRESSOR
CCR REGENERATION VENT
EPN: JJ-5
FIN: JJ5
PURGE GAS
CCR
FRESH CATALYST
HOT OIL
39DC3902
39DC3903
39DC3904
39DC3905
39BA3905
39BA3904
39BA3903
39BA3902
SEPARATOR
OFF GAS
LPG
NAPHTHA
FUEL GAS
39FA3910
39DA3902
DEPENTANIZER
REACTORS
SPENT CATALYST
CHARGE HEATER
EPN: JJ-2
FIN: 39BA3902-5
NHT/CCR Fugitives
EPN: F-39
FIN: 39
BZ/TOL to UDEX
39DA3903
PLATFORMATE SPLITTER
LP TOLUENE
HP TOLUENE
39DA3905
TRC COLUMN
XYLENE
EPN: JJ-6
FIN: 39BA3906
39DA3906
39BA3906
FUEL GAS
XRC RBLR
XRC COLUMN
C9/C10 to HAF
39DA3904
GASOLINE SPLITTER
C10+ to PMB
PROCESS FLOW DIAGRAM
CCR/TOL FRAC



RECYCLE
COMPRESSOR
39GB3900
M/U H_2
NAPHTHA
EPN: JJ-4
FIN: 39BA3900
CHARGE HEATER
39BA3900
FUEL
GAS
39DC3900
REACTOR
39FA3902
SEPARATOR
NHT/CCR Fugitives
EPN: F-39
FIN: 39
SOUR GAS
LPG
39DA3900
DEPENTANIZER
DESULFURIZED
NAPHTHA
EPN: JJ-4
FIN: 39BA3901
HOT OIL
HEATER
39BA3901
FUEL
GAS
PROCESS FLOW DIAGRAM
NHT

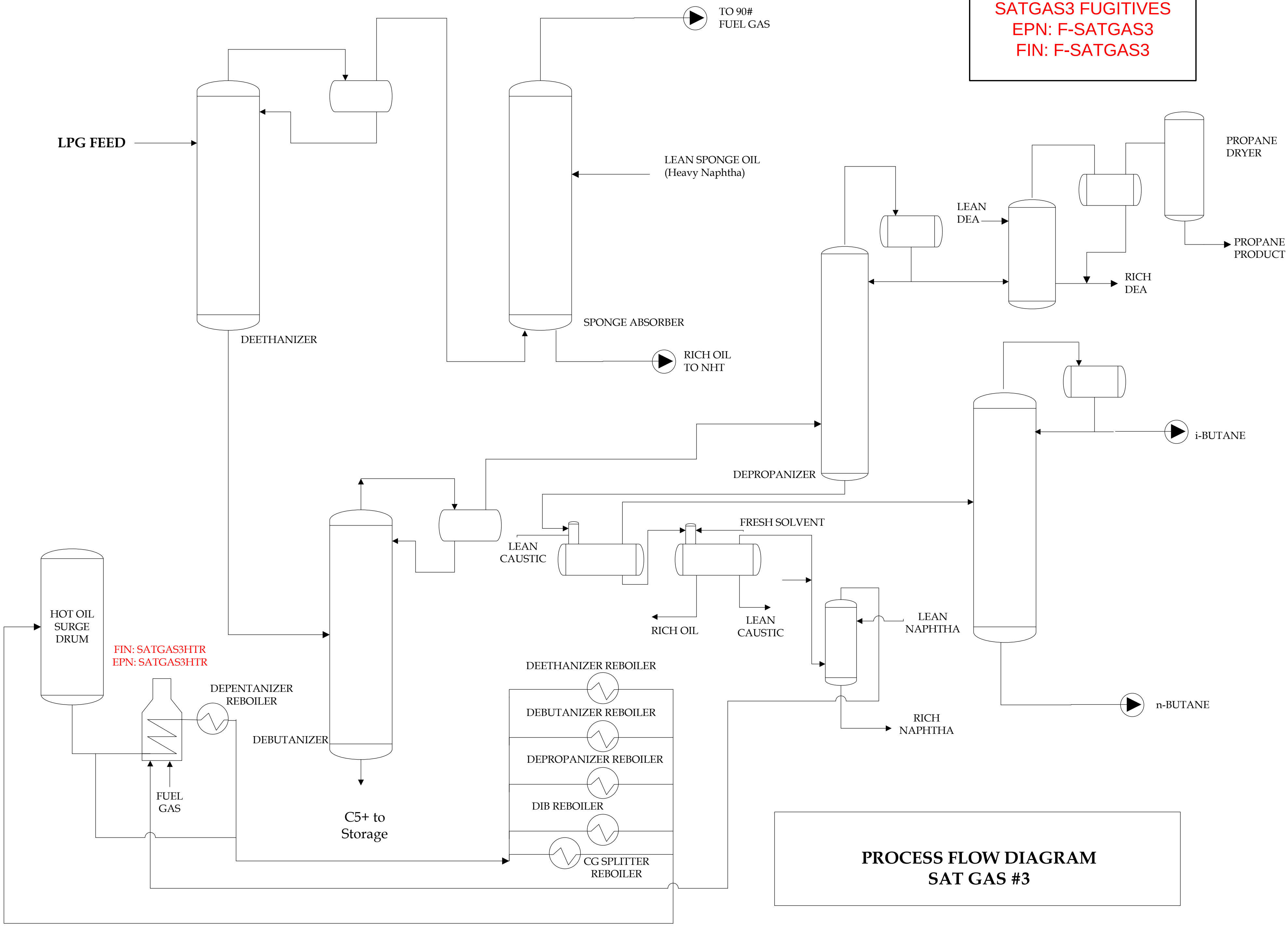


PROCESS FLOW DIAGRAM
DHT Unit (Previously GOHT Unit)



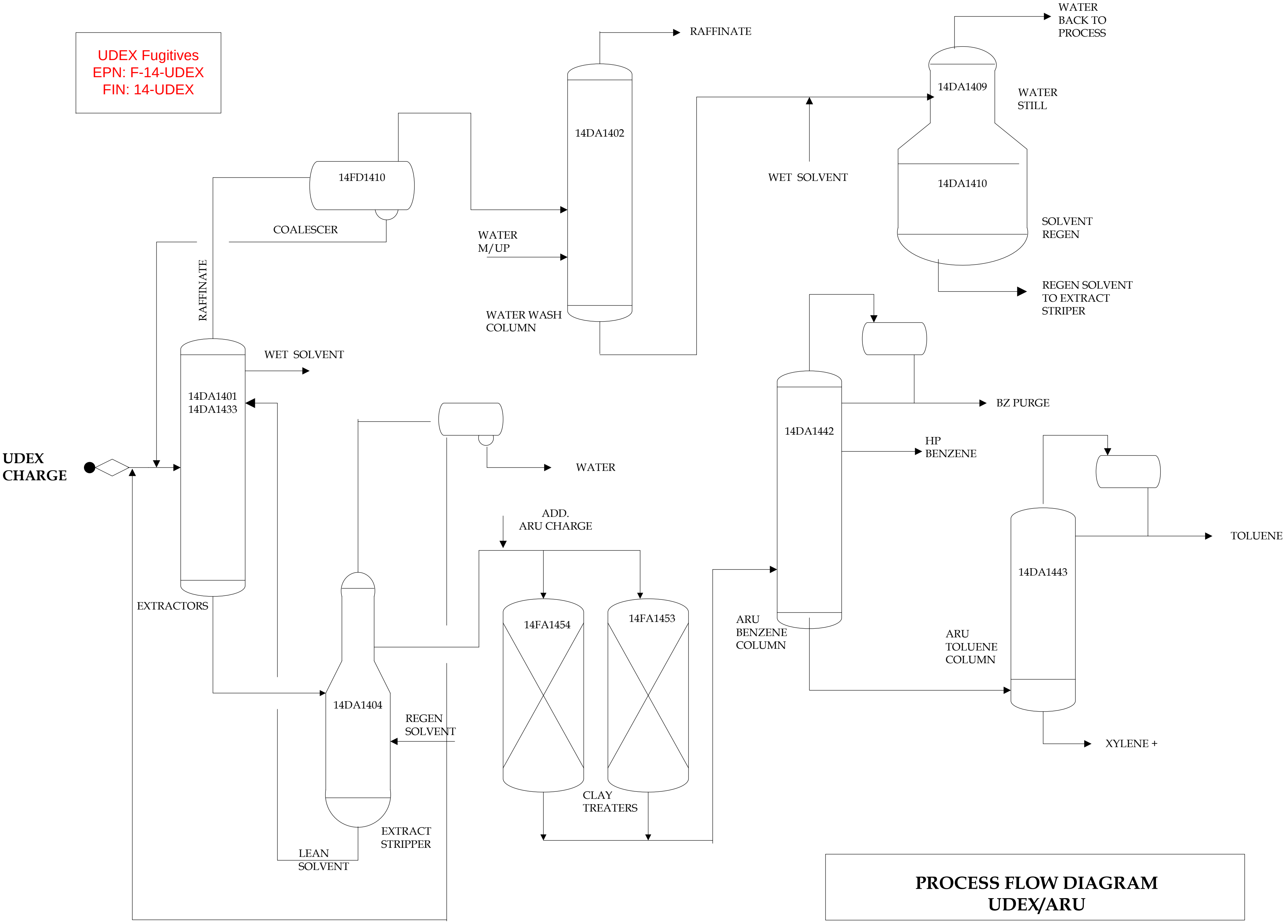
PROCESS FLOW DIAGRAM
MID CRUDE

SATGAS3 FUGITIVES
EPN: F-SATGAS3
FIN: F-SATGAS3

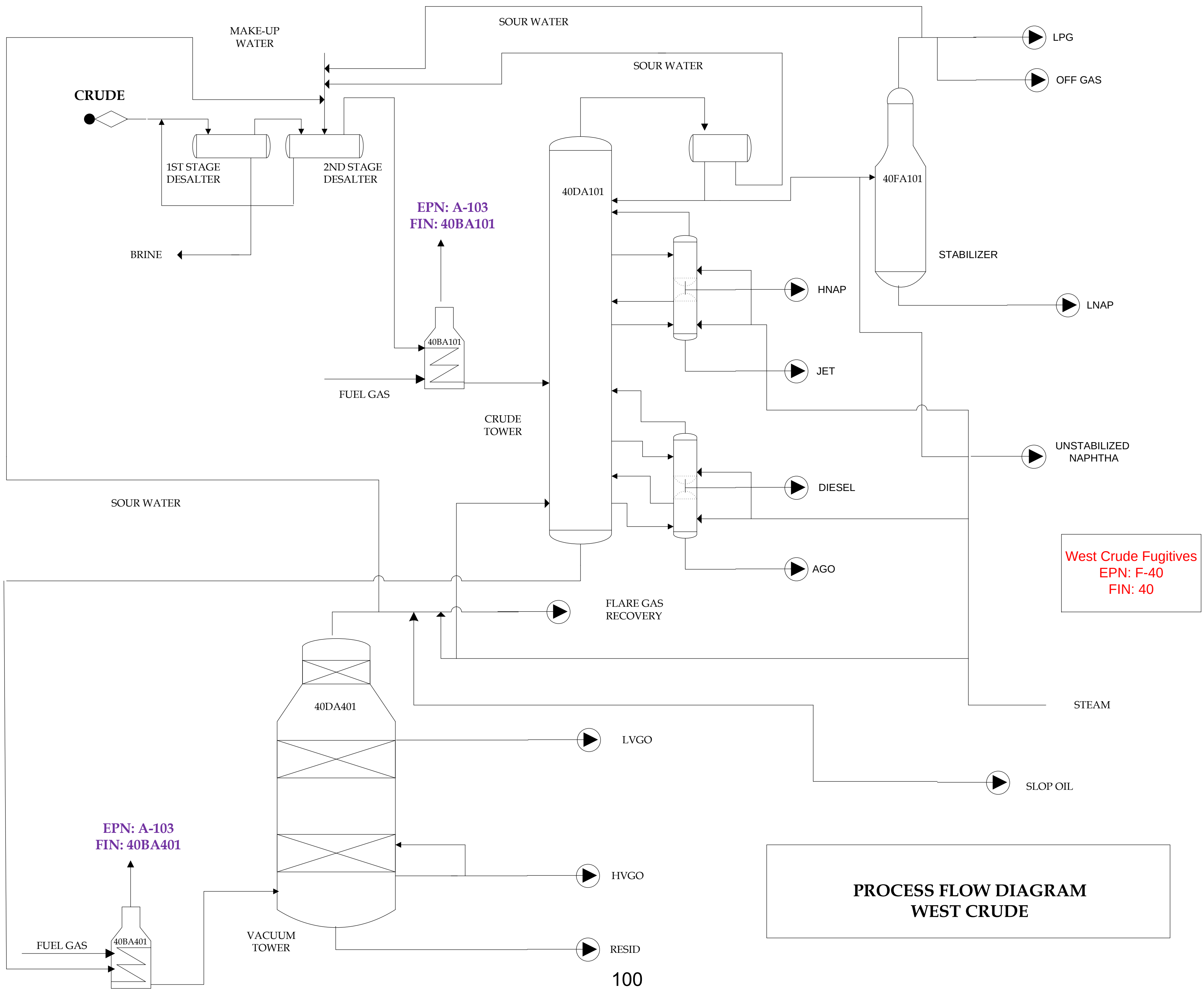


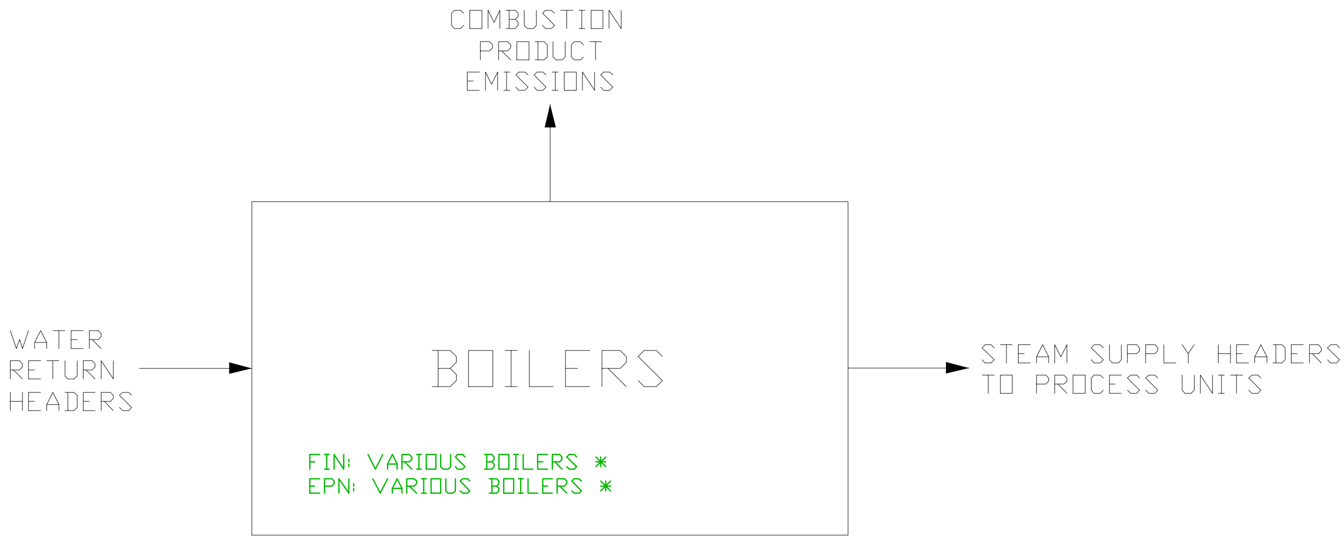
PROCESS FLOW DIAGRAM
SAT GAS #3

UDEX Fugitives
EPN: F-14-UDEX
FIN: 14-UDEX



PROCESS FLOW DIAGRAM
UDEX/ARU


SOUR WATER
MAKE-UP WATER
SOUR WATER
LPG
OFF GAS
CRUDE
1ST STAGE DESALTER
2ND STAGE DESALTER
40DA101
40FA101
EPN: A-103
FIN: 40BA101
BRINE
STABILIZER
HNAP
LNAP
40BA101
JET
FUEL GAS
CRUDE TOWER
UNSTABILIZED NAPHTHA
SOUR WATER
DIESEL
West Crude Fugitives
EPN: F-40
FIN: 40
AGO
FLARE GAS RECOVERY
40DA401
STEAM
LVGO
SLOP OIL
EPN: A-103
FIN: 40BA401
HVGO
PROCESS FLOW DIAGRAM
WEST CRUDE
FUEL GAS
40BA401
VACUUM TOWER
RESID



* There are four boilers potentially affected by the project. Any of these boilers could potentially see an increase in utilization as a result of the project. Therefore, the four boilers have been grouped together into an emission source called Various boilers. Each of the boilers has their own vent stack.

WAID ENVIRONMENTAL

FLINT HILLS RESOURCES CORPUS CHRISTI, LLC

BOILERS PROCESS W. REFINERY CC,TX.

Drawn By	Start Date	Rev. Date	DWG Name	Rev. No.
DWW	7/9/08	6/25/13	BOILERS	5

H\CLIENTS\FLINTHILL WEST\KRW8409\WP\CONFTABLET2\GHC APPL PFD

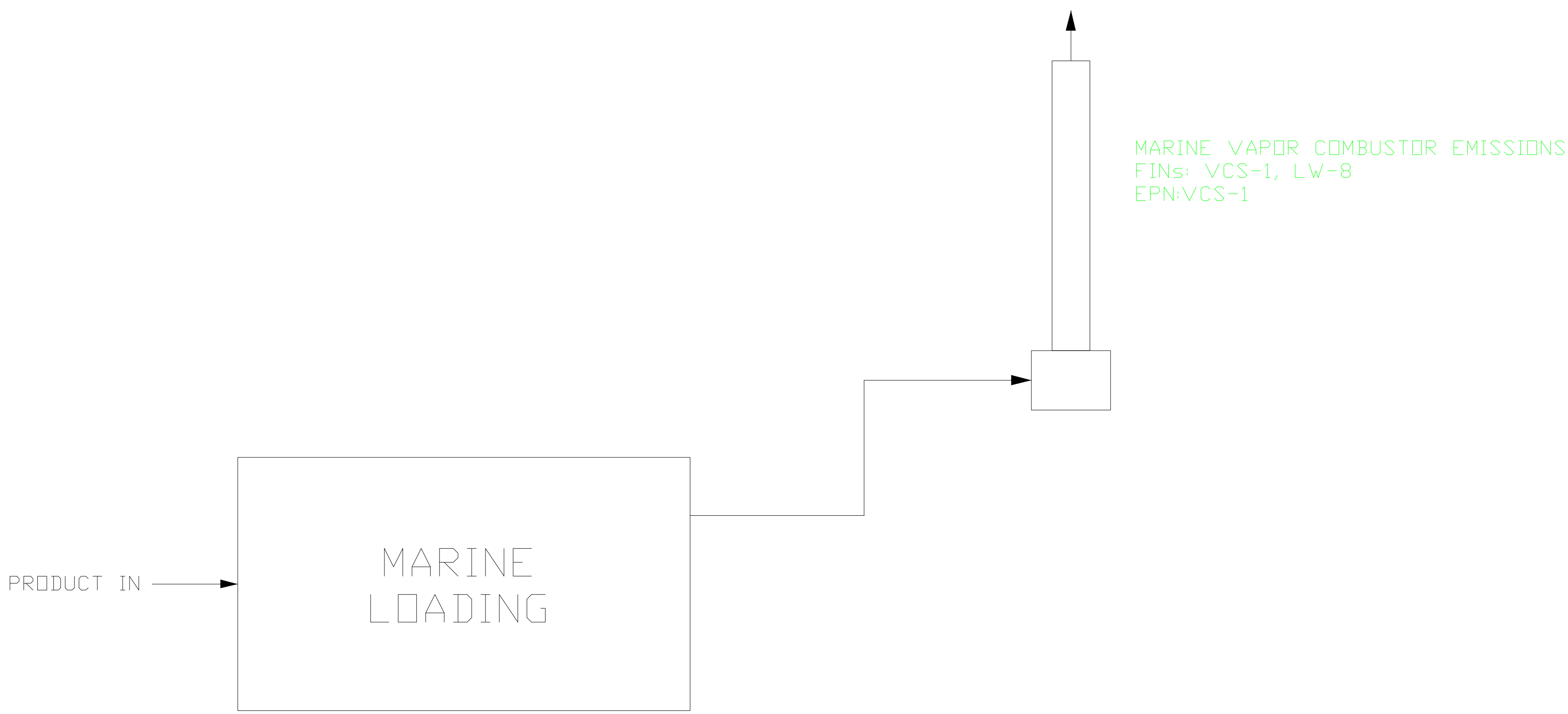
ENVIRONMENTAL

FLINT HILLS RESOURCES CORPUS CHRISTI, LLC

MONROE FLARE PROCESS W. REFINERY CC,TX.

Drawn By	Start Date	Rev. Date	DWG Name	Rev. No.
DWW	6/7/06	12/10/12	MONROE FLARE	4

H\CLIENTS\FLINTHILL WEST\KRW8409\WP\CONFDENTIAL TABLET2 PFD\GH



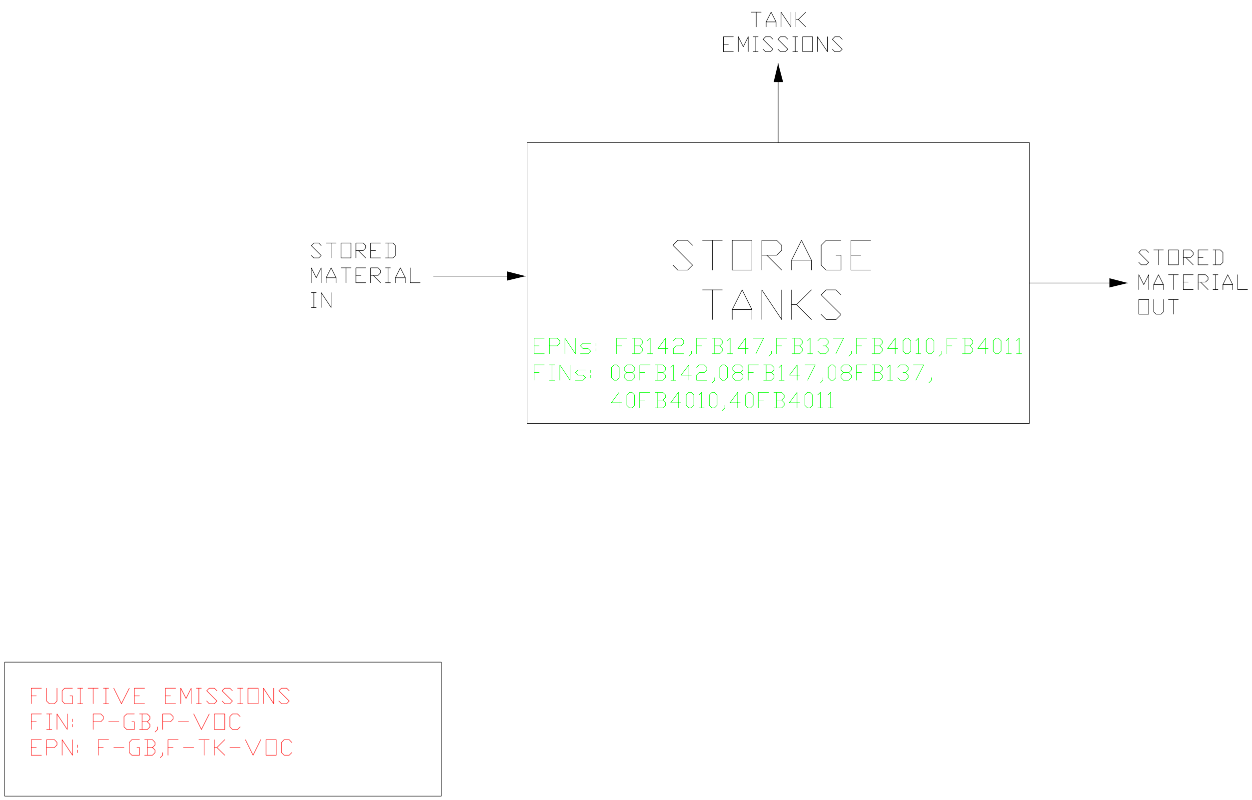
WAID ENVIRONMENTAL

FLINT HILLS RESOURCES CORPUS CHRISTI, LLC

MARINE VAPOR COMBUSTION PROCESS FLOW DIAGRAM

Drawn By	Start Date	Rev. Date	DWG Name	Rev. No.
DWW	7/9/10	11/27/12	MARINE	10

H\CLIENTS\FLINTHILL WEST\KRW8409\WP\CONFTABLET2\GHC APPL PFD



PROCESS FLOW DIAGRAM
STORAGE TANKS

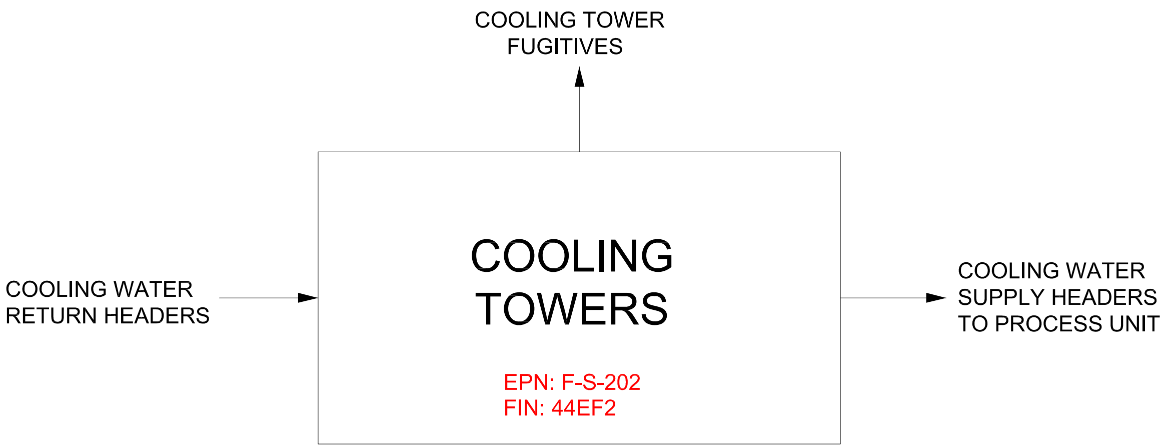
WAID ENVIRONMENTAL

FLINT HILLS RESOURCES CORPUS CHRISTI, LLC

STORAGE TANKS PROCESS FLOW DIAGRAM

Drawn By	Start Date	Rev. Date	DWG Name	Rev. No.
DWW	7/9/08	11/26/12	WWT	3

H\CLIENTS\FLINTHILL WEST\KRW8409\WP\CONFTABLET2\GHC APPL PFD



PROCESS FLOW DIAGRAM
COOLING TOWERS

WAID ENVIRONMENTAL

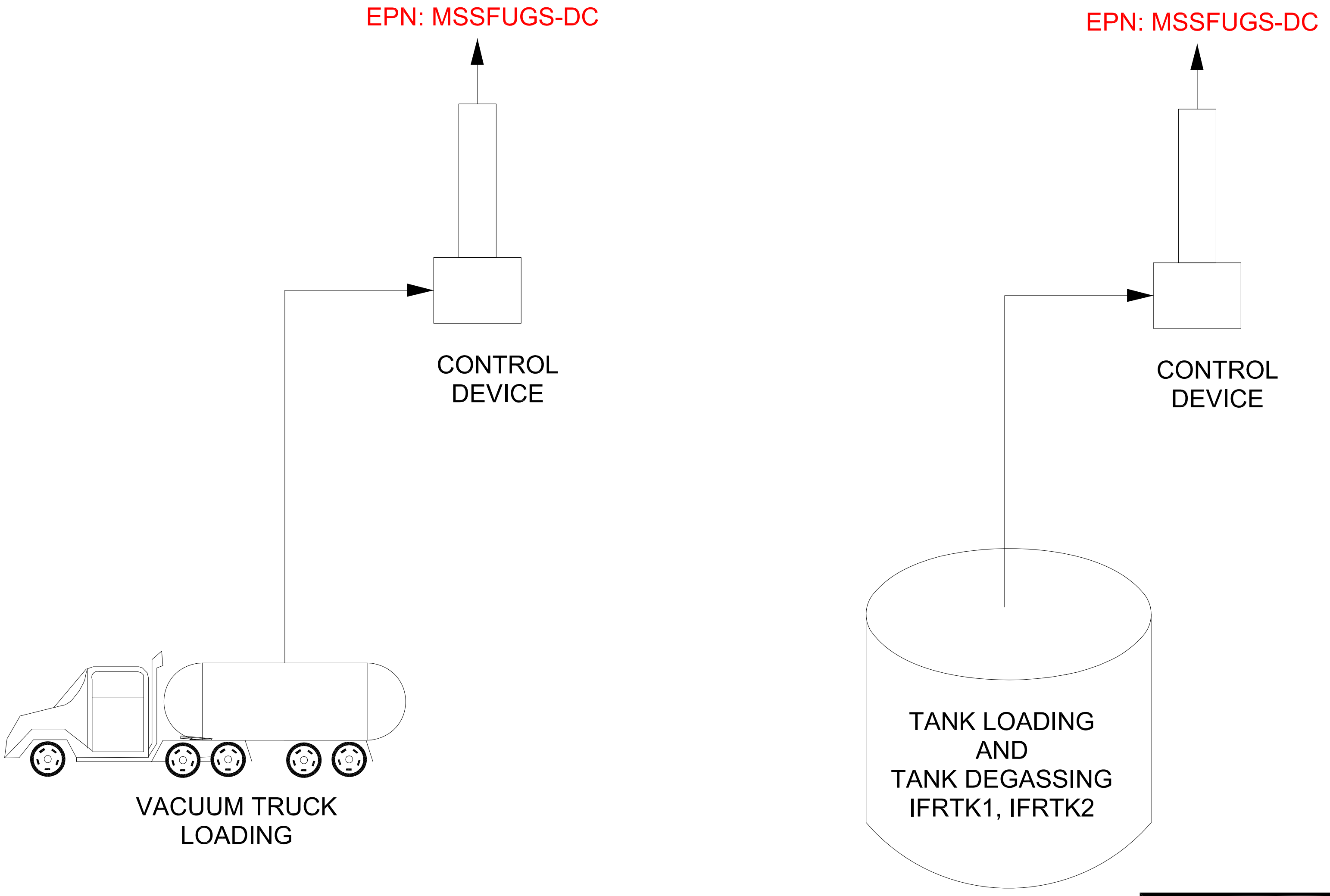
FLINT HILLS RESOURCES CORPUS CHRISTI, LLC

COOLING TOWERS PROCESS FLOW DIAGRAM

Drawn By	Start Date	Rev. Date	DWG Name	Rev. No.
DWW	7/9/08	1/15/14	COOLTWRS	4

H:\CLIENTS\FLINTHILL WEST\KRW8409\WP\CONFTABLET2s PFDs\GHGapplic PFDs

START-UP/SHUTDOWN/MAINTENANCE ACTIVITIES FROM DOMESTIC CRUDE PROJECT
PROCESS FLOW DIAGRAM



WAID ENVIRONMENTAL

FLINT HILLS RESOURCES CORPUS CHRISTI, LLC

START-UP/SHUTDOWN/MAINTENANCE ACTIVITIES FROM DOMESTIC CRUDE PROJECT

Drawn By	Start Date	Rev. Date	DWG Name	Rev. No.
DWW	6/19/13	6/19/13	WWT	1

H\CLIENTS\FLINTHILL WEST\KRW8409\WP\CONFTABLET2s PFDs\GHGapplic PFDs

Section 9.0

NAAQS AND PSD INCREMENT AIR QUALITY ANALYSIS

Air Dispersion Modeling

This application does not include an air dispersion analysis for GHGs. EPA has stated that the air dispersion modeling requirements of the PSD program do not apply to GHGs. EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases," states:

> Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause or contribute to a violation of the NAAQS is [sic] not applicable to GHGs. Thus, we do not recommend that PSD applicants be required to model or conduct ambient monitoring for CO2 or GHGs.

See "PSD and Title V Permitting Guidance for Greenhouse Gases," (March 2011); *See also* Prevention of Significant Deterioration and Title V Greenhouse Gas Permitting Rule," 75 Fed. Reg. 31,520 (2012).

GHG Preconstruction Monitoring

This application does not include a preconstruction monitoring analysis for GHG. This is consistent with EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases," which states:

> EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs.

Section 10.0

ANALYSIS OF CLASS 1 AREA IMPACTS

This application does not include Class I area impacts analysis for GHG. This is consistent with EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases," which states:

> Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.

As EPA further explained when it adopted the Tailoring Rule, "if a facility triggers [PSD] review for regulated NSR pollutants that are non-GHG pollutants for which there are established NAAQS or increments, the air quality, additional impacts, and Class I requirements would apply to those pollutants." 75 Fed. Reg. 31,520 (June 3, 2010). However, because the proposed project will not result in a criteria pollutant net emissions increase greater than a PSD significance threshold and, therefore, will not trigger PSD review for any non-GHG pollutant, a Class I impacts analysis also is not included for those pollutants.

Section 11.0

IMPACTS ON VISIBILITY, SOILS, VEGETATION, AND ASSOCIATED GROWTH

This application does not include a PSD additional impacts analysis for GHG. This is consistent with EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases," which states:

> Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.

As EPA further explained when it adopted the Tailoring Rule, "if a facility triggers [PSD] review for regulated NSR pollutants that are non-GHG pollutants for which there are established NAAQS or increments, the air quality, additional impacts, and Class I requirements would apply to those pollutants." 75 Fed. Reg. 31,520 (June 3, 2010). However, because the proposed project will not result in a criteria pollutant net emissions increase greater than a PSD significance threshold and, therefore, will not trigger PSD review for any non-GHG pollutant, an additional impacts analysis also is not included for those pollutants.

Section 12.0

COMPLIANCE WITH OTHER EPA AIR REGULATIONS

State Minor NSR Permitting

This project—including construction of the new emission units, changes to existing emission units, and emissions increases from upstream and downstream affected units—will not trigger federal PSD for any non-GHG new source review (NSR)-regulated pollutants. In fact, the overall project will result in decreased emissions of non-GHG pollutants, with the exception of ammonia. Therefore, for non-GHG pollutants, construction of new emission units and changes to existing emission units are subject only to Texas minor NSR requirements. Emission information for these non-GHG NSR pollutants is set forth in the relevant Texas minor NSR permit applications, and is not provided in this GHG-only application.

Other EPA Air Regulations

Aside from the GHG PSD permit requirements described above, there are no other emission standards or standards of performance applicable to GHG emissions from the proposed project (*e.g.*, NSPS, NESHAPS, SIP, or FIP requirement, or local district rules). Emissions standards and standards of performance applicable to non-GHG emissions from the proposed project are addressed in the Texas minor NSR permit applications.

Section 13.0

REQUIREMENTS OF OTHER ACTS

Endangered Species Act

Section 7(a)(2) of the Endangered Species Act ("ESA"), 16 U.S.C. § 1536(a)(2), and its implementing regulations at 50 C.F.R. Part 402, requires EPA to consult with the U.S. Fish and Wildlife Service ("USFWS") or the National Marine Fisheries Service ("NMFS"), or both under certain circumstances, to ensure that EPA's issuance of a GHG PSD permit is not likely to jeopardize the continued existence of any federally listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat. FHR has prepared and submitted a final biological assessment to EPA Region 6 on February 13, 2014 to support EPA's obligations under ESA Section 7.

Coastal Zone Management Act

The Coastal Zone Management Act ("CZMA") was enacted on October 27, 1972, to encourage coastal states, Great Lake States, and United States territories and commonwealths (collectively referred to as "coastal states") to develop comprehensive programs to manage and balance competing uses of and impacts to coastal resources. The CZMA emphasizes the primacy of state decision-making regarding the coastal zone. Section 307 of the CZMA, 16 U.S.C. § 1456, called the federal consistency provision, is an incentive for states to join the national coastal management program and is a tool that states use to manage coastal uses and resources and to facilitate cooperation and coordination with federal agencies.

Federal license or permit activities and federal financial assistance activities that have reasonably foreseeable coastal effects must be fully consistent with the enforceable policies of state coastal management programs. Federal license or permit activities are activities proposed by a non-federal applicant requiring federal authorization, and federal financial assistance activities are proposed by state agencies or local governments applying for federal funds for activities with coastal effects. Each coastal state promulgates a coastal management program for federal approval. Each federally-approved coastal management program includes a list of federal license or permit activities which the coastal state wishes to review for consistency with the management program. Those federal license or permit activities that are unlisted by the coastal state are subject to the Section 307 consistency review only if the coastal state elects—after having received proper notification of the federal license or permit activity—to review the activity for consistency. *Compare* 15 C.F.R. § 930.54(a)(1) ("State agencies shall notify Federal agencies, applicants, and the Director of unlisted activities affecting any coastal use or resource which require State agency review within 30 days from notice of the license or permit application, that has been submitted to the approving Federal agency, otherwise the State agency waives its right to review the unlisted activity.") *with id.* § 930.53(d) ("No federal license or permit described on an approved list shall be issue issued by a Federal agency until the requirements of this subpart have been satisfied.").

Texas has incorporated the requirements of Section 307 and its implementing regulations. *See* Texas Administrative Code, tit. 31, § 506.30(a) ("Upon filing an application for a federal agency action listed under § 506.12 of this title (relating to Federal Actions Subject to the Coastal Management Program), the applicant shall provide to the council secretary a consistency certification . . . ."). Texas has not included EPA's issuance of PSD preconstruction permits on its list of federal license or permit activities. *See id.* § 506.12(a)(2) (listing five non-PSD EPA licenses or permits subject to the consistency requirement). Accordingly, EPA's action in issuing a PSD GHG permit does not trigger the requirement for FHR to obtain a consistency certification under Texas' federally-approved coastal management program. In accordance with 15 C.F.R. § 930.54(a)(2), publication of the availability of this application in the Federal Register will constitute constructive notice to Texas of the proposed permit activity. In addition, FHR will provide a copy of this application to the Texas General Land Office.

National Historic Preservation Act

Section 106 of the National Historic Preservation Act ("NHPA"), 16 U.S.C. § 470, and its revised regulations, 36 C.F.R. Part 800, require EPA to take into account the effects of its actions (*e.g.*, any action authorized, funded, or carried out by EPA) on historic properties, and to provide the Advisory Council on Historic Preservation ("ACHP") a reasonable opportunity to comment on those undertakings. Historic properties are defined in Federal law as those properties that are listed in, or meet the criteria for listing in, the National Register of Historic Places ("NRHP"). This is typically carried out through consultation with the State Historic Preservation Officer ("SHPO"), and in the case of projects involving tribal lands, with the tribal representative.

FHR has prepared and submitted a cultural resources assessment ("CRA") to EPA Region 6 on February 17, 2014 that reviews the potential effects of the project's construction, operations, and air emissions on historical properties or other culturally significant features or landscapes within a designated Area of Potential Effect ("APE").

Magnuson-Stevens Fisheries Conservation and Management Act

Under Section 305(b) of the Magnuson-Stevens Fisheries Conservation and Management Act ("MSA"), federal agencies must consult with the Secretary (*i.e.*, the National Marine Fisheries Service, or "NMFS") "with respect to any action authorized, funded, or undertaken, or proposed to be authorized, funded, or undertaken, by such agency that may adversely affect any essential fish habitat identified under [the MSA]." 16 U.S.C. § 1855(b)(2). NMFS has identified essential fish habitat (EFH) to include parts of the Corpus Christi Inner Harbor that are adjacent to the FHR Corpus Christi East Refinery.

The MSA regulations define "adverse effect" to mean:

> [A]ny impact that reduces quality and/or quantity of EFH. Adverse effects may include direct or indirect physical, chemical, or biological alterations of the waters or substrate and loss of, or injury to, benthic organisms, prey species and their habitat, and other ecosystem components, if such modifications reduce the quality and/or quantity of EFH. Adverse effects to EFH may result from actions occurring within EFH or outside of EFH and may include site-specific or habitat-wide impacts, including individual, cumulative, or synergistic consequences of actions.

50 C.F.R. § 600.810.

As part of the consultation process, Federal agencies should provide early notice to NMFS of federal actions that may adversely affect EFH, 50 C.F.R. 600.920(a)(3), and must provide NMFS with a written EFH Assessment. 50 C.F.R. § 600.920(e). FHR has prepared and submitted an EFH assessment to EPA Region 6 on February 26, 2014 to support EPA's obligations under MSA Section 305(b).

Section 14.0

CONFIDENTIAL BUSINESS INFORMATION CLAIMS

FHR does not assert any claim of confidential business information with respect to any of the information contained in this application.

Appendix A

TCEQ GUIDANCE DOCUMENT FOR EQUIPMENT LEAK FUGITIVES

October 2000
Draft

Air Permit Technical Guidance for Chemical Sources:

Equipment Leak Fugitives

Air Permits Division
TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Published and distributed by:
Texas Commission on Environmental Quality
P.O. Box 13087
Austin TX 78711-3087

TECHNICAL DISCLAIMER

THIS PACKAGE IS INTENDED FOR INSTRUCTIONAL USE ONLY

References to abatement technologies are not intended to represent minimum or maximum levels of BACT. Determinations of BACT are made on a case by case basis as part of the New Source Review of permit applications. BACT determinations are always subject to adjustment in consideration of specific process requirements, air quality concerns, and recent developments in abatement technology. Additionally, specific health effects concerns may indicate stricter abatement than required by the BACT determination.

The represented calculation methods are intended as an aid in the completion of an acceptable submittal; alternative calculation methods may be equally acceptable if they are based upon, and adequately demonstrate, sound engineering assumptions or data.

The enclosed regulations are applicable as of the publication date of this package, but are subject to revision during the application preparation and review period. It is the responsibility of applicants to remain abreast of regulation developments which may affect their industries.

The special conditions included in this package are for purposes of example only. Special conditions included in an actual permit are written by the reviewing engineer to address specific permit requirements and operating conditions.

The electronic version of this document may or may not contain attachments or forms (such as the PI-1, Standard Exemptions, or Tables) that can be obtained electronically elsewhere on the TCEQ Internet site.

EQUIPMENT LEAK FUGITIVES

This document is intended to aid the permit applicant in the preparation of a technically complete permit application. The fugitive emissions discussed in this standardization package refer to the emissions from piping components and associated equipment including valves, connectors, pumps, compressor seals, relief valves, sampling connections, process drains, and open-ended lines. Uncaptured emissions emanating from other sources such as cooling towers, oil/water separators, material stockpiles, and loading operations are not addressed.

The TCEQ encourages pollution prevention, specifically source reduction, as a means of eliminating or reducing air emissions from industrial processes. The applicant should consider opportunities to prevent or reduce the generation of emissions at the source whenever possible through methods such as product substitutions, process changes, or training. Considering such opportunities prior to designing or applying "end-of-pipe" controls can not only reduce the generation of emissions, but may also provide potential reductions in subsequent control design requirements (e.g., size) and costs.

Table of Contents

I. REGULATIONS GOVERNING VOC EQUIPMENT LEAKS

A number of state and federal regulations exist that address volatile organic compounds (VOC) equipment leaks. All permit applications must demonstrate that a facility will be in compliance with all applicable Rules and Regulations. New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants (NESHAPS and MACT) and TCEQ 30 TAC Chapter 115 have fugitive emission monitoring programs that vary depending on the specific industry, the material, and the county where the source is located. Each of the major fugitive emission monitoring programs required by state or federal regulation is listed below by industry type. For specific details, refer to the actual regulation in question.

PETROLEUM REFINERIES

<u>30 TAC Chapter 115 (TCEQ Regulation V)</u>

30 TAC § 115.352 Beaumont/Port Arthur, Dallas/Ft. Worth, Houston/Galveston and El Paso Areas

Leak definition of 10,000 ppmv for pump seals and compressors

Leak definition of 500 ppmv for all other components

30 TAC §115.322 Gregg, Nueces and Victoria Counties

Leak definition of 10,000 ppmv for all components

<u>New Source Performance Standards (NSPS) (40 CFR Part 60)</u>

40 CFR Part 60 Subpart GGG - Equipment Leaks of VOC in Petroleum Refineries (*Excluding those Subject to Subparts VV or KKK*)

<u>National Emission Standards for Hazardous Air Pollutants (NESHAPS) (40 CFR Part 61)</u>

Subpart J for benzene

<u>Maximum Allowable Control Technology (MACT) (40 CFR 63)</u>

Subpart CC - Petroleum Refineries

SYNTHETIC ORGANIC CHEMICALS MANUFACTURING INDUSTRY (SOCMI)

30 TAC Chapter 115 (TCEQ Regulation V)

30 TAC § 115.352 Beaumont/Port Arthur, Dallas/Ft. Worth, Houston/Galveston and El Paso Areas

Leak definition of 10,000 ppmv for pump seals and compressors

Leak definition of 500 ppmv for all other components

30 TAC § 115.322 Gregg, Nueces and Victoria Counties

Leak definition of 10,000 ppmv for all components

New Source Performance Standards (NSPS)

40 CFR Part 60 Subpart VV Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry

National Emission Standards for Hazardous Air Pollutants (NESHAPS)

Subpart F for vinyl chloride, Subpart J for benzene

Hazardous Organic NESHAPS (HON)

Subpart H - Equipment Leaks

Subpart I - Certain Process Subject to the Negotiated Regulation for Equipment Leaks

NATURAL GAS PROCESSING

30 TAC Chapter 115 (TCEQ Regulation V)

30 TAC § 115.352 Beaumont/Port Arthur, Dallas/Ft. Worth, Houston/Galveston and El Paso Areas

Leak definition of 10,000 ppmv for pump seals and compressors

Leak definition of 500 ppmv for all other components

New Source Performance Standards (40 CFR Part 60)

Subpart KKK Equipment Leaks of VOC from Onshore Natural Gas Processing Plants

(Excluding those Covered Under Subparts VV or GGG)

Maximum Allowable Control Technology (MACT) (40 CFR Part 63)

Subpart HH - Oil and Natural Gas Production Facilities

ADDITIONAL REQUIREMENTS

Please note that the regulations listed above are not an exhaustive list. New MACT standards are being proposed and promulgated that may contain LDAR requirements for specific industries. In addition, 30 TAC Chapter 115 may list fugitive emission inspection and monitoring requirements in sections other than those written specifically to address fugitive emissions. For example, fugitive inspection and maintenance requirements for marine terminals and gasoline terminals are contained in Section 115.214 of 30 TAC Chapter 115, Subchapter C, "Volatile Organic Compound Transfer Operations."

II. QUANTIFYING UNCONTROLLED EMISSIONS

Fugitive emission rates are estimates based on leak frequencies found in case studies of chemical plants, oil and gas facilities, refineries and gasoline marketing terminals. An average leak factor is used to determine what the fugitive emission rate is for an area, a facility, or an entire plant. In general, there are five different sets of fugitive emission factors: (1) refinery factors, (2) oil and gas production operations factors, (3) SOCMI factors, (4) petroleum marketing terminal factors, and (5) derived factors used for specific compounds. Within each of the five sets, different factors are used to estimate the uncontrolled emission rates for each specific type of component (connectors, valves, pumps, etc.) and for the type of material in service (light liquid, heavy liquid, or gas/vapor). Each of the leak factors accepted by the TCEQ for use in permit applications is discussed below. The emission factors are provided on Attachment II.

SOCMI FACTORS

The SOCMI factors are generally for use in chemical plants including chemical processes that are located in a refinery. SOCMI factors are divided into three different sets which are applied in different situations.

The original SOCMI average factors were developed to represent fugitive emission rates from all chemical plants. The SOCMI average factors are found in EPA 453/R-95-017, page 2-12. From these factors, the TCEQ further derived two additional sets of factors: "SOCMI with ethylene" to be used for components in service of material which is greater than 85% ethylene, and "SOCMI without ethylene" to be used where the ethylene concentration is less than 11%. For streams where the ethylene concentration is between 11% - 85%, the SOCMI average factors should be applied.

SOCMI NON-LEAKER FACTORS AND LOW VAPOR PRESSURE COMPOUNDS

Fugitive emissions from components in service where the material has a vapor pressure between 0.147 psia and 0.0147 psia should be estimated with the SOCMI Non-Leaker factors. The SOCMI Non-Leaker factors were developed from test data where no leaking emissions occurred above

10,000 ppmv; therefore, using the Non-Leaker factors assumes that no leaks will occur over the 10,000 ppmv leak detection threshold. For materials with a vapor pressure less than 0.0147 psia, fugitive emissions should be calculated using the SOCMI without ethylene factors with the Audio/Visual/Olfactory (AVO) reduction credits applied. In both cases, a weekly AVO inspection similar to the example condition given in Attachment I(E) will be required in the permit special conditions.

REFINERY FACTORS

Refinery factors are given in the Environmental Protection Agency's (EPA) Compilation of Air Pollutant Emission Factors, AP-42 (4th Edition), or EPA 453/R-95-017, page 2-13. Refinery factors are used when estimating fugitive emissions in a refinery process or production facility. A chemical process, such as a MTBE production unit, may be located in a refining facility but because it is not considered a refinery process, the refinery factors should not be used to calculate that specific unit's fugitive emissions.

PETROLEUM MARKETING TERMINAL FACTORS

In February of 1995 the Air Permits Division approved the use of the Petroleum Marketing Terminal Factors found in EPA document EPA-453/R-95-017, "Protocol for Equipment Leak Emission Estimates." These factors are used to estimate fugitive emissions from components at gasoline distribution facilities that are one-step removed from local gasoline stations and other end-users. Although gasoline distribution facilities may also handle jet fuel and diesel, gasoline is their primary product. Loading racks at chemical plants and refineries may not use these factors. Use of the petroleum terminal factors is accompanied by an AVO LDAR program performed on a monthly basis as specified in a permit special condition similar to the example condition in Attachment I(F). The petroleum marketing terminal factors include the appropriate reduction credit for the AVO inspection; therefore, no additional reductions to the factors are necessary. The decision to require an AVO program instead of an instrument inspection was based on the EPA/API bagging study of various gasoline distribution facilities employing a variety of LDAR programs. The results of the study indicated that little or no improvement in fugitive emission control was achieved when an instrument was used to detect leaks at this type of facility.

OIL AND GAS PRODUCTION OPERATIONS FACTORS

The Oil and Gas Production factors are based on EPA evaluated data on equipment leak emissions from the oil and gas production industry gathered by the American Petroleum Institute (API). There are four different equipment service categories covered by the Oil and Gas Production factors: Gas, Heavy Oil (< 20° API gravity), Light Oil (> 20° API gravity), and Water/Light Oil (water streams in light oil service with a water content between 50% and 99%). The gas factors estimate total hydrocarbon emissions; therefore, the calculated emission rates must be multiplied by the weight percentage of C3+ compounds in the gas stream to get a total VOC rate for permitting purposes. It is important to note that the Oil and Gas Production Operations gas factors replace the Gas Plant Fugitive Factors from the previous EPA protocol document (EPA-453/R-93-026).

Operators of crude oil pipeline facilities which handle weathered or "dead" crude may use the Oil and Gas Heavy Oil (< 20° API gravity) factors to estimate fugitive emissions. This decision was based upon technical demonstrations by the industry that weathered crude is free of the entrained gases and easily volatilized light ends which affected the fugitive emissions factors based upon studies at tank batteries and other upstream facilities.

PHOSGENE, BUTADIENE, AND ETHYLENE OXIDE FACTORS

Specific factors have been developed for use with components in phosgene, butadiene, and ethylene oxide service. These factors are used to estimate fugitive emissions from components in phosgene, butadiene, and ethylene oxide service when monitored with the 28MID Leak Detection and Repair Program at the following leak definitions:

Phosgene	50 ppmv
Butadiene	100 ppmv

Ethylene Oxide   500 ppmv

Note: the EO connector factor does not include instrument monitoring. An additional reduction credit can be taken if connector monitoring is required.

ODOROUS/INORGANIC COMPOUNDS

For odorous or toxic inorganic compounds such as chlorine (Cl_2), ammonia (NH_3), hydrogen sulfide (H_2S), hydrogen fluoride (HF), and hydrogen cyanide (HCN), fugitive emissions are calculated in the same manner as any VOC fugitive emissions according to the type of facility. Although the VOC emission factors were not developed specifically for use with inorganic compounds, they are presently the best tool available for estimating fugitive emissions of inorganics.

The calculated uncontrolled emission rates can be reduced according to the credit allowed by any monitoring program to be implemented at the facility. The emission rates of the inorganic compounds are determined through speciating (see Attachment IV) the calculated total emission rate by multiplying the total emission rate by the weight percent of each individual compound present in the stream. Note that there are no additional monitoring requirements for inorganic compounds if the maximum predicted off-property impact is acceptable. If it is expected that the leakage of these compounds would be detected by smell before an instrument monitoring device would register a leak, see Section III for information on reducing the emission rate of inorganic compounds through a physical inspection program.

LIGHT/HEAVY LIQUIDS

Several of the factors make a distinction between the leak rate for heavy liquids and light liquids. For purposes of choosing an emission factor, heavy liquids are defined as having a vapor pressure of 0.044 psia or less. Light liquids are the liquids with vapor pressures higher than 0.044 psia at 68°F.

COMPONENTS EXEMPT FROM MONITORING REQUIREMENTS

Emissions from components exempt from monitoring requirements based on size, physical location at a facility, or low vapor pressure *MUST* be calculated and included in the estimated fugitive emission rate regardless of any monitoring exemptions. There are presently no exemptions based on component size in Regulation V for the ozone nonattainment counties as mandated by EPA. In Gregg, Nueces, and Victoria Counties, valves with a nominal size of two inches or less are exempt from monitoring provided that certain requirements are met.

None of the 28 Series Leak Detection and Repair (LDAR) programs requires instrument monitoring of valves less than two inches in diameter; however, if the facility is located in an ozone nonattainment county and is subject to monitoring under 30 TAC 115.352, the two inch exemption will be removed from the permit conditions to be consistent with the regulation. In addition, certain non-accessible components, as defined in 30 TAC Chapter 115, are exempt from monitoring requirements. Monitoring requirements also vary depending on the vapor pressure of the compound. Fugitive emissions from components in heavy liquid service may be exempt from monitoring; however, the uncontrolled emissions must still be estimated.

SCREWED FITTINGS, LIQUID RELIEF VALVES, AND NON-EMITTING SOURCES

Factors have not been developed for certain types of piping components. In order to ensure consistency the TCEQ has designated the factor of a component with similar characteristics to be used to estimate fugitive emissions as follows:

I. Emissions from screwed fittings should be estimated in the same manner as flanges.

II. Emissions from liquid relief valves should be estimated in the same manner as light liquid valves.

III. Emissions from agitators should be estimated in the same manner as light liquid pumps.

Fugitive emissions should not be estimated from the following sources:

1) Tubing size lines (flexible lines ≤ 0.5'' in diameter) and equipment if they are not subject to monitoring by any federal or state regulation

2) Non-piping type fittings (swedgelock or ferrule fittings),
3) Streams where the operating pressure is at least 0.7 psi below ambient pressure,
4) Mixtures in streams where the VOC has an aggregate partial pressure of less than 0.002 psi at 68° Fahrenheit.

**Regardless of the guidance given above, if a piping component is required to be monitored by a state or federal regulation, the fugitive emissions from that component must be estimated.

PROCESS DRAINS

Facilities subject to fugitive emission monitoring under 30 TAC §§115.322 and 352 are required to monitor process drains on an annual basis. A 75 percent reduction credit may be applied for annual monitoring of process drains at a leak threshold of 500 ppmv provided the drain is designed in such a manner that repairs to leaking drains can be achieved. For example, flushing a water seal on a leaking process drain would constitute repair, so a 75 percent reduction credit may be applied.

At present, the Refinery Factors are the only set of accepted emission factors that include a factor for fugitive emissions from process drains. This factor may be applied to any process drain regardless of facility or industry type.

HOURS OF OPERATION

Fugitive emission factors are independent of process unit throughput and are assumed to occur if there is material in the line, regardless of the activity of the process. Because fugitive emissions occur when there is material in the line, the hours in service for all streams should always be 8,760 hours annually regardless of process downtime. Any exception to this service time would require a permit condition requiring the lines to be purged during process downtime.

CORRELATION EQUATIONS AND PLANT SPECIFIC FACTORS

The use of various correlation equations developed by EPA for estimating fugitive emissions is not accepted for permitting purposes. Since actual monitoring data is required by the equations, they can be used for estimating actual emissions for emission inventory purposes.

Emission factors developed for individual facilities are also not accepted for permitting purposes. Such factors are the results of individual bagging studies which the TCEQ Air Permits Division does not have the resources to quality assure.

III. FUGITIVE EMISSION REDUCTION OPTIONS

There are two methods by which fugitive emission rates can be reduced: leak detection and repair (LDAR) programs and equipment specification.

LEAK DETECTION AND REPAIR (LDAR) PROGRAMS

Leak detection and repair programs can be differentiated by four key criteria:

1) Leak definition
2) Monitoring frequency
3) Properties of the monitored compounds
4) Requirements for repair

The leak definition is the monitored concentration, defined in ppmv, which identifies a leaking component needing repair.

The second criterion, monitoring frequency, varies depending on the component types and the LDAR program in place. Components typically must be monitored on a quarterly basis; however, some programs allow facilities to skip monitoring periods when the percentage of leaking components is maintained under a specified rate.

The third criterion involves LDAR programs which define the components to be monitored by the vapor pressure of the material in the component and the weight percent of VOC in the stream.

The fourth and final criterion is whether the program repair requirements are directed or non-directed maintenance. A directed maintenance program requires that a gas analyzer be used in conjunction with the repair or maintenance of leaking components to assure that a minimum leak concentration is achieved. If a replacement is required to fix a leaking component, the replaced component should be re-monitored within 15 days. A non-directed maintenance does not require the use of a gas analyzer during repair or maintenance of a leaking component.

40 CFR Part 60, 40 CFR Part 61, MACT and Chapter 115 all have LDAR programs required for specific industries, counties, and materials. Refer to Section I to determine if a facility must meet the requirements of these monitoring and repair programs. Also, remember that a facility may be subject to more than one monitoring program and that meeting the requirements of one program does not exempt a facility from the requirements of another. For example, a chemical plant in Harris County may be subject to the monitoring requirements of Regulation V and also have a permit containing the 28MID LDAR program.

There are five instrument assisted leak detection and repair programs to choose from for permitting purposes: 28M, 28RCT, 28VHP, 28MID and 28LAER. LDAR programs allow emission control credits for instrument monitored components and for the physical (AVO) inspection of connectors. These credits can only be given in cases where the components are actually inspected and for components for which the LDAR program could result in emission reductions. A 30% reduction of fugitive connector emission rates is allowed when a weekly AVO inspection is performed. As mentioned previously, components smaller than two inches not subject to fugitive monitoring by regulation are exempt from monitoring requirements. Instrument monitoring of connectors and components less than two inches can be given a reduction credit consistent with the LDAR program if additional emission reductions are needed or desired. The 28LAER LDAR program is used.

strictly to control fugitive emissions which are part of a non-attainment permit. For facilities which are not subject to a non-attainment permit, the same emission reductions may be attained by implementing the 28MID program in conjunction with the 28CNTA LDAR program for connectors.

In an effort to keep the LDAR programs used as permit special conditions as concise as possible, the procedures to justify delay of repair for a leaking component are not outlined in the 28 series LDAR programs and default to the requirements of 30 TAC Chapter 115. The 28 series LDAR programs also use the 30 TAC Chapter 115 definition for nonaccessible valves.

Each of the five instrument monitoring programs is outlined in Table 1.

Table I
Leak Detection and Repair (LDAR) Program Options

LDAR Program		**28M**	**28 RCT**	**28 VHP**	**28 MID**	**28 LAER**
Leak Definition	Pumps and Compressors	10,000 ppmv	10,000 ppmv	2,000 ppmv	500 ppmv	500 ppmv
	All Other Components	10,000 ppmv	500 ppmv	500 ppmv	500 ppmv	500 ppmv [2]
Applicable Vapor Pressure		> 0.5 psia at 100°F	> 0.044 psia at 68°F	> 0.044 psia at 68°F	> 0.044 psia at 68°F	> 0.044 psia at 68°F
Monitoring Frequency		Quarterly	Quarterly	Quarterly	Quarterly	Quarterly [2]
Directed/Nondirected Maintenance		Nondirected	Nondirected	Nondirected	Directed	Directed
Equivalent State/Federal Programs		40CFR Part 60/40 CFR Part 61	30 TAC 115.352 [1]	MACT	N/A	Nonattainment NSR

1) Except in Gregg, Nueces, and Victoria Counties where 28 M applies.
2) Connectors are required to be monitored annually with an instrument under 28LAER.

LOW VAPOR PRESSURE COMPOUNDS

Compounds with low vapor pressures can present a problem with instrument monitoring. No reduction credits are allowed for valves and pumps in heavy liquid service under any of the five 28 Series LDAR programs or 30 TAC 115 as components in heavy liquid service are not required to be monitored. An applicant may propose to monitor these components and take the appropriate reduction credits as noted in Attachment III; however, the applicant must demonstrate that leaking components can be detected by implementing an instrument assisted fugitive monitoring program. For materials with vapor pressures below 0.147 psia, implementing a LDAR program with a 10,000 ppmv leak detection definition could be useless as leaking components may never be detected. For example, a component in heavy liquid service (vapor pressure < 0.044 psia) which is subject to a LDAR program with a leak definition of 10,000 ppmv would have a theoretical-saturation concentration of 0.044/14.7 = 2990 ppmv. Depending on the instrument response factor for the compounds being measured, this concentration may or may not be a measurable quantity; thus, it may not be possible to demonstrate an actual emission reduction via instrumental monitoring. These components would never get any increased maintenance or improved emission rates as a result of a LDAR Program with a 10,000 ppmv leak definition; therefore, these components cannot receive any reduction credit. To reduce these emissions, the applicant would have to commit to a 500 ppmv or 2,000 ppmv leak definition program.

AUDIO/VISUAL/OLFACTORY WALK-THROUGH INSPECTION

If the predicted off-property impact of an inorganic/odorous compound is unacceptable based on a predicted exceedance of an Effects Screening Level (ESL) or a maximum allowable ground level concentration specified in one of the regulations, the applicant will be required to commit to an Audio/Visual/Olfactory (AVO) walk-through inspection similar to the permit condition shown in Attachment I(E). Note that the repair time given in this condition may be extended on a case by case basis.

Inorganic/odorous compound fugitive emission rates controlled through the AVO inspection are determined as follows:

> The total number of components in service of the compound in question should be multiplied by the appropriate "SOCMI without ethylene" emission factor. The AVO reduction credits found in Attachment III should then be applied to the uncontrolled inorganic/odorous compound emission rates.

Please note that the AVO inspection program may only be applied to inorganic compounds for which instrument monitoring is not available. In limited instances the AVO inspection program may be applied to extremely odorous organic compounds, such as mercaptans.

REDUCTION CREDIT FOR ANNUAL AND QUARTERLY CONNECTOR MONITORING

Annual instrument monitoring of connectors at a 500 ppmv leak detection limit may receive a 75 percent reduction credit. This determination is based on information contained in the 1993 EPA document "Protocol for Equipment Leak Fugitives" and the results from a limited amount of monitoring data. The control effectiveness percentages given in the protocol document are based on the type of facility, monitored data, and the corresponding reduction in the percentage of leaking flanges. A lower common denominator was used to establish the appropriate reduction credit as it is preferable to allow a single reduction credit for both chemical facilities and refineries. Thus, the 75 percent reduction credit is suitable for use at both petroleum refineries and SOCMI facilities

where the flanges are monitored annually at 500 ppmv. The 28CNTA LDAR program specifies the monitoring and recordkeeping necessary to receive the 75 percent reduction credit. This program may be used in conjunction with any of the other 28 series LDAR programs.

Quarterly instrument monitoring of connectors at a 500 ppm leak detection limit may receive a 97 percent reduction credit. This credit is equivalent to that received by valves monitored at the same leak detection limit and frequency. Although in theory an applicant could monitor connectors quarterly at a 10,000 ppm leak detection limit with a 75 percent credit, there would be a greater benefit for the cost in moving to a more stringent leak definition for the valves and other components prior to implementing connector monitoring. The 28CNTQ LDAR program specifies the monitoring and recordkeeping necessary to receive the 97 percent reduction credit. This program may be used in conjunction with any of the other 28 series LDAR programs.

EQUIPMENT SPECIFICATION

There are certain options that may be implemented in the design of a facility to prevent fugitive emissions from escaping into the atmosphere. When calculating emission rates, various control credits may be applied to components in service as described below. Also, LDAR program monitoring for identified types of equipment is not required if 100 percent reduction credit is given.

Relief Valves

100% control may be taken if one of the following conditions is met:

1) Route relief valve vents to an operating control device
2) Equip with a rupture disc and pressure sensing device (between the valve and disc) to monitor for disc integrity

Note that for new facilities, BACT guidelines generally require that all relief valves vent to a control device.

Pumps

Certain types of pumps are designed to be "leakless" and as such can be given 100% control. Any of the following designs are accepted as leakless pumps:

1) Canned Pumps
2) Magnetic Drive Pumps
3) Diaphragm Pumps
4) Double mechanical seals and the use of a barrier fluid at a higher pressure than the process
5) Double mechanical seals and venting the barrier fluid seal pot to a control device

Valves

100% control may be taken if one of the following conditions is met:

1) Use of bellows valves with bellows welded to both the bonnet and stem
2) Use of diaphragm-type valves
3) Use of seal-welded, magnetically actuated, packless, hermetically sealed control valves

Connectors

Connectors may receive 100% control credit if the connections are welded together around the circumference of the connection such that the flanges are no longer capable of being disassembled by simply unbolting the flanges.

Compressors

Compressors must be designed with enclosed distance pieces and must have the crankcase venting to a control device to be given 100% control.

Double Mechanical Seals

Any component employing double mechanical seals may be given a 75% credit. If the seals are monitored, then use the appropriate monitoring credit.

DESIGN OPTIONS

There are certain options that may be incorporated into the design of a facility to minimize piping components, improve maintenance and/or reduce susceptibility to leaks. While some of these options may not result in reduction credits for fugitive emissions, they can result in lower maintenance costs and improved performance in some cases.

Overall

1) Design equipment layout to minimize pipe run lengths and associated connectors.
2) Minimize the use of valves and other components.
3) Minimize whenever possible the use of relief valves.
4) Optimize piping and component metallurgy for compatibility with process streams and/or physical environment to reduce corrosion potential.

Pumps

1) Use of pressure transfer to eliminate the need for pumps.
2) Use of submerged pumps which limit the exposure of potential leaks to the atmosphere.

Valves

1) Optimize length of time between leaks by using special packing sets and stringent adherence to packing procedures.
2) Use of on-line direct injection repair equipment.
   Note: This option may introduce an additional potential leak path for the valve if corrosion occurs around the tap.

Connectors

1) Eliminate the use of screwed fittings smaller than 2 inches in diameter.
   Note: BACT for fugitives does not allow the use of screwed connections greater than 2 inches in diameter.
2) Use of new technologies which have been deemed by the TCEQ to be equivalent to flanges.

Compressors

1) Designs with lower leak potentials such as diaphragm compressors.
2) Shaft seal design such as carbon rings, double mechanical seals or buffered seals.

3) Design options such as internal balancing, double inlet or gland eductors.

QUANTIFYING FUGITIVE EMISSION REDUCTIONS

Here are several important points to remember when calculating fugitive emission rates:

1) All components must be accounted for when estimating emission rates regardless of exemptions from monitoring requirements.

2) Taking an emission reduction for monitoring implies that all of those components will be monitored regardless of exemptions.

3) Non-accessible components and other unmonitored components must be clearly identified and separated from monitored components when calculating emission rates.

4) All components given emission reduction credits for monitoring must be capable of having reduced emissions through the monitoring program, i.e., any components represented as being monitored must have sufficient vapor pressure to allow the reduction.

5) Representations of emission reductions in a permit application will result in permit special conditions requiring monitoring for certain components based on the emission estimates.

6) Instrument monitoring of connectors is not required by any of the LDAR programs other than 28 LAER. A 30% reduction can be taken for the required weekly walk-through inspection. For quarterly instrument monitoring of connectors under the 28CNTQ LDAR program, the valve credit corresponding to the appropriate leak definition for the LDAR program may be applied instead of the 30% credit. A 75% credit may be taken for annual connector monitoring at a 500 ppm leak definition in conjunction with the 28CNTA LDAR program. The 28CNT LDAR programs are used in addition to the other 28 series LDAR programs if connector monitoring is required by special circumstances.

7) Emission calculations should include a component count for those components with a 100%

control efficiency with a footnote describing the specific method of control.

IV. INFORMATION NEEDED IN A PERMIT APPLICATION

COMPONENT COUNT, TYPE, AND SERVICE CATEGORY

The estimated fugitive emission rate is solely dependent on the number of components in service; therefore, a specific component count is necessary. The count should be separated into the component type categories, i.e., connector, valve, etc. For each specific component type, the number of components should be divided into the appropriate physical service category: gas, light liquid, heavy liquid, chlorine, etc.

With the separated source totals, an estimation of fugitive emission rates with no LDAR program in place can be made. This estimate is simply the emission factor, based on the specific compound and where it is in service, multiplied by the number of components in that service. As an example, for a valve in VOC light liquid service in a refinery, the factor used is 0.024 (lb/hr)/source; therefore, 10 of these valves will emit a total of 0.24 lb/hr. Annual emissions are determined from the short-term emission rate by assuming 8,760 hours per year of operation. The emission factors used in the calculations should be clearly footnoted to show the source of the factors.

CLAIMING EMISSION REDUCTIONS

Emission reductions claimed either though equipment specification or through any of the TCEQ leak detection and repair programs must be clearly identified. The fugitive emission calculations should show the emission factor, the appropriate reduction credit from Attachment III, and the final emission rate for each component type and, if applicable, from each different process stream. Refer to Attachment IV for a sample calculation.

SPECIATED EMISSIONS BY CHEMICAL

A speciation, or breakdown of the different compounds found in a process line, is necessary if the chemical composition is not 100% pure. The speciation is necessary to determine the off-property impact for each different chemical emitted from a fugitive source.
For example, if a line is 80% toluene and 20% ethylene, the emission rate would need to reflect the

estimated quantity of emissions for each compound. Simply multiplying the emission rate by the weight percent of each compound yields the specific emission rate for that compound. If the weight percent of a particular compound varies from one process stream to another, then the fugitive emission rate for each area should be calculated separately, multiplied by the appropriate weight percent, and then totaled. The permit applicant may also group different streams together and determine the maximum percentage of each compound for that group. When using this method, the percentages may total over 100 percent. The total emission rate of each individual chemical should be shown on the Table 1(a), Emission Source Table, submitted with the permit application.

MODIFICATIONS

When submitting a permit application that involves changes to existing permitted equipment, show the existing component counts and emissions rate, the proposed component counts and emissions rate, and the overall changes. The new and increased emissions will be evaluated as part of the permit review process to determine if any off-property impact concerns exist.

V. BEST AVAILABLE CONTROL TECHNOLOGY GUIDELINES

An integral part of the permitting process is the determination of Best Available Control Technology (BACT) for all new and modified sources. Since fugitive emissions are estimated as a whole for a process unit or area, the addition of new piping components will trigger a BACT review for all of the piping components. Table II provides guidelines for determining BACT for process fugitive emissions when submitting a permit application.

Table II

Best Available Control Technology Guidelines for Fugitive Emissions

Uncontrolled Annual Fugitive Emission Rate	**Best Available Control Technology (BACT)**
< 10 tpy	May Not Require Monitoring †
$10 \leq x < 25$ tpy	28M Program †
≥ 25 tpy	28VHP Program

† If subject to TCEQ 30 TAC 115.352, 28RCT applies

It is important to note that the uncontrolled annual emission rate triggers and corresponding LDAR programs given in Table II are guidelines only; a case-by-case review will be performed for all permit applications. Separate applicability determinations must also be made for 30 TAC Chapter 115 (TCEQ Regulation V), 40 CFR Part 60, 40 CFR Part 61 or MACT affected sources. It is important to note that a more stringent program may be requested if it is currently in use at other units at the same plant site. For example, a new unit at a large chemical plant would be expected to implement at least the 28M leak detection and repair program even if the uncontrolled fugitive emissions from the new unit are calculated to be less than 10 tons annually.

In addition to the instrument monitoring requirements, certain components have additional requirements to meet BACT. Open-ended lines are required to be equipped with a cap, plug, blind flange or second valve as BACT. New relief valves are required to vent to a control device as BACT for any potential releases and as a side result any fugitive emissions are also controlled. If instrument monitoring is chosen for existing relief valves, monitoring must be performed quarterly regardless of the accessibility of the relief valves. Additional information on BACT for existing relief valves is contained in "Permit Review of Non-traditional Sources of Air Contaminants" by Alan Pegues, PhD., P.E., 1993.

OFF-PROPERTY IMPACTS REVIEW

The control technology determination is separate from the off-property impacts assessment performed during the permit review process. A more stringent LDAR program (up to 28MID) may be required if the TCEQ Toxicology and Risk Assessment Section determines that the predicted off-property impact of fugitive emissions is unacceptable. If impacts problems still exist with the 28MID LDAR program implemented, the following additional steps may be required:

1) Monitoring of connectors using an organic vapor analyzer as opposed to weekly physical inspections
2) Equipment specifications for leakless operation (See Section III)
3) Applicant developed proposal

SPECIAL CONDITIONS - 28M

Piping, Valves, Connectors, Pumps, and Compressors in Volatile Organic Compounds (VOC) Service - 28M

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.5 psia at 100°F or at maximum process operating temperature if less than 100°F or (2) to piping and valves two inches nominal size and smaller or (3) where the operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined in TCEQ 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring period after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations § 60.485(a) - (b) (40 CFR 60.485[a] - [b]).

G. Except as may be provided for in the special conditions of this permit, all pump and compressor seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. Seal systems that prevent emissions may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure or seals degassing to vent control systems kept in good working order.

Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves, connectors, compressor seals, and pump seals found to be emitting VOC in excess of 10,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Every reasonable effort shall be made to repair a leaking component as specified in this paragraph within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TCEQ Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

I. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

J. Fugitive emission monitoring required by an applicable New Source Performance Standard (NSPS), 40 CFR Part 60, or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS), 40 CFR Part 61, may be used in lieu of Items F through I of this condition.

Compliance with the requirements of this condition does not assure compliance with requirements of NSPS or NESHAPS and does not constitute approval of alternate standards for these regulations.

SPECIAL CONDITIONS - 28RCT

Piping, Valves, Connectors, Pumps, and Compressors in Volatile Organic Compounds (VOC) Service - 28RCT

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure equal to or less than 0.044 psia at 68°F or (2) * **REMOVE IF SUBJECT TO REG. V* to piping and valves two inches nominal size and smaller** or (3) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TCEQ 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations Part 60.485(a) - (b).

Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump and compressor seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump and compressor seals found to be emitting VOC in excess of 10,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired.

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TCEQ Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

J. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

K. Fugitive emission monitoring required by 30 TAC Chapter 115 may be used in lieu of Items F through I of this condition.

Compliance with the requirements of this condition does not assure compliance with requirements of an applicable New Source Performance Standard or an applicable National Emission Standard for Hazardous Air Pollutants and does not constitute approval of alternative standards for these regulations.

SPECIAL CONDITIONS - 28VHP

Piping, Valves, Connectors, Pumps, and Compressors in Volatile Organic Compounds (VOC) Service - 28VHP

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68°F or (2) * **REMOVE IF SUBJECT TO REG. V* to piping and valves two inches nominal size and smaller** or (3) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TCEQ 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations Part 60.485(a) - (b).

Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump and compressor seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump and compressor seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired.

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TCEQ Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

J. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

K. Alternative monitoring frequency schedules of 30 TAC Sections 115.352-115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR 63, Subpart H, may be used in lieu of Items F through G of this condition.

Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard, or an applicable National Emission Standard for Hazardous Air Pollutants and does not constitute approval of alternative standards for these regulations.

Piping, Valves, Connectors, Pumps, and Compressors in (insert compound) Service - Intensive Directed Maintenance - 28MID

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. These conditions shall not apply (1) where the concentration in the stream is less than XX percent by weight or (2) where the volatile organic compounds (VOC) has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68°F or (3) *** REMOVE IF SUBJECT TO REG. V.* to piping and valves two inches nominal size and smaller** or (4) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TCEQ 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer with a directed maintenance program. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations § 60.485(a) - (b).

A directed maintenance program shall consist of the repair and maintenance of components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. All new and replacement pumps and compressors shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These seal systems need not be monitored and may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

All other pump and compressor seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.

H. Damaged or leaking valves, connectors, compressor seals, and pump seals found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TCEQ Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

I. In lieu of the monitoring frequency specified in paragraph F, valves in gas and light liquid service may be monitored on a semiannual basis if the percent of valves leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Valves in gas and light liquid service may be monitored on an annual basis if the percent of valves leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of valves leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

J. The percent of valves leaking used in paragraph I shall be determined using the following formula:

$$(Vl + Vs) \times 100/Vt = Vp$$

Where:

Vl = the number of valves found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Vs = the number of valves for which repair has been delayed and are listed on the facility shutdown log.

Vt = the total number of valves in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor valves.

Vp = the percentage of leaking valves for the monitoring period.

K. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard, or an applicable National Emission Standard for Hazardous Air Pollutants and does not constitute approval of alternative standards for these regulations.

SPECIAL CONDITIONS - 28LAER

Piping, Valves, Connectors, Pumps, Agitators, and Compressors in Volatile Organic Compounds (VOC) Service - Intensive Directed Maintenance - 28LAER

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. With the exception of paragraph N, these conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by TCEQ 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through. In addition, all connectors shall be monitored by leak-checking for fugitive emissions at least annually using an approved gas analyzer with a directed maintenance program.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer with a directed maintenance program. Non-accessible valves shall be monitored by leak-checking for fugitive emissions at least annually using an approved gas analyzer with a directed maintenance program. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in Title 40 Code of Federal Regulations § 60.485(a) - (b).

A directed maintenance program shall consist of the repair and maintenance of components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. All new and replacement pumps and compressors shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These seal systems need not be monitored and may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

All other pump, compressor, and agitator seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.

H. Damaged or leaking valves, connectors, agitator seals, compressor seals, and pump seals found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. At the discretion of the TCEQ Executive Director or his designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

I. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or his designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

J. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard, or an applicable National Emission Standard for Hazardous Air Pollutants and does not constitute approval of alternative standards for these regulations.

K. In lieu of the monitoring frequency specified in paragraph F, valves in gas and light liquid service may be monitored on a semiannual basis if the percent of valves leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Valves in gas and light liquid service may be monitored on an annual basis if the percent of valves leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of valves leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

L. The percent of valves leaking used in paragraph K shall be determined using the following formula:

$$(Vl + Vs) \times 100/Vt = Vp$$

Where:

Vl = the number of valves found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Vs = the number of valves for which repair has been delayed and are listed on the facility shutdown log.

Vt = the total number of valves in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor valves.

Vp = the percentage of leaking valves for the monitoring period.

M. Alternative connector monitoring frequency schedules ("skip options") of 40 Code of Federal Regulations Part 63, Subpart H, National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks, may be used in lieu of the annual connector instrument monitoring required by paragraph E of this permit condition.

N. Any component found to be leaking by physical inspection (i.e., sight, sound, or smell) shall be repaired or monitored with an approved gas analyzer within 15 days to determine whether the component is leaking in excess of 500 ppmv of VOC. If the component is found to be leaking in excess of 500 ppmv of VOC, it shall be subject to the repair and replacement requirements contained in this special condition.

AUDIO, VISUAL AND OLFACTORY (AVO) INSPECTION

Piping, Valves, Pumps, and Compressors in (insert compound) Service

A. Audio, olfactory, and visual checks for (insert compound) leaks within the operating area shall be made every four hours.

B. Immediately, but no later than one hour upon detection of a leak, plant personnel shall take the following actions:

(1) Isolate the leak.

(2) Commence repair or replacement of the leaking component.

(3) Use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

Date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the Texas Commission on Environmental Quality (TCEQ) upon request.

PETROLEUM MARKETING TERMINAL AUDIO, VISUAL, AND OLFACTORY (AVO) INSPECTION

Piping, Valves, Pumps, and Compressors in Petroleum Service

A. Audio, olfactory, and visual checks for petroleum product leaks within the operating area shall be made monthly.

B. Every reasonable effort shall be made to repair or replace a leaking component within 15 days after a leak is found. If the repair or replacement of a leaking component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired or replaced until a scheduled shutdown shall be identified in a list to be made available to representatives of the Texas Commission on Environmental Quality (TCEQ) upon request.

Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the TCEQ upon request.

28 CNTA

In addition to the weekly physical inspection required by Item E of Special Condition XX, all connectors in gas\vapor and light liquid service shall be monitored annually with an approved gas analyzer in accordance with Items F thru J of Special Condition XX. Alternative monitoring frequency schedules ("skip options") of 40 Code of Federal Regulations Part 63, Subpart H, National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks, may be used in lieu of the monitoring frequency required by this permit condition. Compliance with this condition does not assure compliance with requirements of applicable state or federal regulation and does not constitute approval of alternative standards for these regulations.

28CNTQ

A. In addition to the weekly physical inspection required by Item E of Special Condition XX, all accessible connectors in gas\vapor and light liquid service shall be monitored quarterly with an approved gas analyzer in accordance with Items F thru J of Special Condition XX.

B. In lieu of the monitoring frequency specified in paragraph A, connectors may be monitored on a semiannual basis if the percent of connectors leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Connectors may be monitored on an annual basis if the percent of connectors leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of connectors leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

Uncontrolled SOCMI Fugitive Emission Factors

Equipment/Service	SOCMI Average[1]	SOCMI Without C_2[2]	SOCMI With C_2[2]	SOCMI Non-Leaker[3]
Valves				
Gas/Vapor	0.0132	0.0089	0.0258	0.00029
Light Liquid	0.0089	0.0035	0.0459	0.00036
Heavy Liquid	0.0005	0.0007	0.0005	0.0005
Pumps				
Light Liquid	0.0439	0.0386	0.144	0.0041
Heavy Liquid	0.019	0.0161	0.0046	0.0046
Flanges/Connectors				
Gas/Vapor	0.0039	0.0029	0.0053	0.00018
Light Liquid	0.0005	0.0005	0.0052	0.00018
Heavy Liquid	0.00007	0.00007	0.00007	0.00018
Compressors	0.5027	0.5027	0.5027	0.1971
Relief Valve (Gas/Vapor)	0.2293	0.2293	0.2293	0.0986
Open-ended Lines[4]	0.0038	0.004	0.0075	0.0033
Sampling Connections[5]	0.033	0.033	0.033	0.033

Notes: All factors are in units of (lb/hr)/component.

1. Factors are taken from EPA Document, EPA-453/R-95-017, November 1995, Page 2-12.
2. Factors are TCEQ derived.
3. Control credit is included in the factor; no additional control credit can be applied to these factors. AVO walk-through inspection required.
4. The 28 Series quarterly LDAR programs require open-ended lines to equipped with a cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.
5. Use the SOCMI Sampling Connection factor for Non-Leaker. Emission factor is in terms of Pounds per Hour per Sample Taken.

Facility/Compound Specific Fugitive Emission Factors

Equipment/ Service	Ethylene Oxide[1]	Phosgene[2]	Butadiene[3]	Petroleum Marketing Terminal[4]	Oil and Gas Production Operations[5]				Refinery[6]
					Gas	Heavy Oil <20° API	Light Oil	Water/Light Oil	
Valves					0.00992	0.0000185	0.0055	0.000216	
Gas/Vapor	0.000444	0.00000216	0.001105	0.0000287					0.059
Light Liquid	0.00055	0.00000199	0.00314	0.0000948					0.024
Heavy Liquid				0.0000948					0.00051
Pumps	0.042651	0.0000201	0.05634		0.00529	0.00113[10]	0.02866	0.000052	
Light Liquid				0.00119					0.251
Heavy Liquid				0.00119					0.046
Flanges/Connectors	0.000555	0.00000011	0.000307		0.00086	0.00000086	0.000243	0.000006	0.00055
Gas/Vapor				0.000092604					
Light Liquid				0.00001762					
Heavy Liquid				0.0000176					
Compressors	0.000767		0.000004		0.0194	0.0000683	0.0165	0.0309	1.399
Relief Valve	0.000165	0.0000162	0.02996		0.0194	0.0000683	0.0165	0.0309	0.35
Open-ended Lines[7]	0.001078	0.00000007	0.00012		0.00441	0.000309	0.00309	0.00055	0.0051
Sampling	0.000088		0.00012						0.033
Connectors					0.00044	0.0000165	0.000463	0.000243	
Other[9]					0.0194	0.0000683	0.0165	0.0309	
Gas/Vapor				0.000265					
Light/Heavy Liquid				0.000287					
Process Drains					0.0194	0.0000683	0.0165	0.0309	0.07

Table Notes: All factors are in units of (lb/hr)/component.

1. Monitoring must occur at a leak definition of 500 ppmv. No additional control credit can be applied to these factors. Emission factors are from EOIC Fugitive Emission Study, Summer 1988.

2. Monitoring must occur at a leak definition of 50 ppmv. No additional control credit can be applied to these factors. Emission factors are from Phosgene Panel Study, Summer 1988.

3. Monitoring must occur at a leak definition of 100 ppmv. No additional control credit can be applied to these factors. Emission factors are from Randall, J. L., et al., Radian Corporation. Fugitive Emissions from the 1,3-butadiene Production Industry: A Field Study. Final Report. Prepared for the 1,3-Butadiene Panel of the Chemical Manufacturers Association. April 1989.

4. Control credit is included in the factor; no additional control credit can be applied to these factors. Monthly AVO inspection required.

5. Factors give the total organic compound emission rate. Multiply by the weight percent of non-methane, non-ethane organics to get the VOC emission rate.

6. Factors are taken from EPA Document EPA-453/R-95-017, November 1995, Page 2-13.

7. The 28 Series quarterly LDAR programs require open-ended lines to equipped with a cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.

8. Emission factor for Sampling Connections is in terms of pounds per hour per sample taken.

9. For Petroleum Marketing Terminals"Other" includes any component excluding fittings, pumps, and valves. For Oil and Gas Production Operations, "Other" includes diaphragms, dump arms, hatches, instruments, meters, polished rods, and vents.

10. No Heavy Oil - Pump factor was derived during the API study. The factor is the SOCMI without C_2 Heavy Liquid - Pump factor with a 93% reduction credit for the physical inspection.

Control Efficiencies for TCEQ Leak Detection and Repair Programs

Equipment/Service	28M	28RCT	28VHP	28MID	28LAER	Audio/Visual/Olfactory Olfactory[1]
Valves						
Gas/Vapor	75%	97%	97%	97%	97%	97%
Light Liquid	75%	97%	97%	97%	97%	97%
Heavy Liquid[2]	0%[3]	0%[4]	0%[4]	0%[4]	0%[4]	97%
Pumps						
Light Liquid	75%	75%	85%	93%	93%	93%
Heavy Liquid[2]	0%[3]	0%[3]	0%[5]	0%[6]	0%[6]	93%
Flanges/Connectors						
Gas/Vapor[7]	30%	30%	30%	30%	75%	97%
Light Liquid[7]	30%	30%	30%	30%	75%	97%
Heavy Liquid	30%	30%	30%	30%	30%	97%
Compressors	75%	75%	85%	95%	95%	95%
Relief Valve (Gas/Vapor)	75%	97%	97%	97%	97%	97%
Open-ended Lines[8]	75%	97%	97%	97%	97%	97%
Sampling Connections	75%	97%	97%	97%	97%	97%

Notes:

1. Audio, visual, and olfactory walk-through inspections are applicable for inorganic/odorous and low vapor pressure compounds referenced in Section II.

2. Monitoring components in heavy liquid service is not required by any of the 28 Series LDAR programs. If monitored with an instrument, the applicant must demonstrate that the VOC being monitored has sufficient vapor pressure to allow the reduction.

3. No credit may be taken if the concentration at saturation is below the leak definition of the monitoring program (i.e. (0.044 psia/14.7 psia) x 10^6 = 2,993 ppmv versus leak definition = 10,000 ppmv)

4. Valves in heavy liquid service may be given a 97% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.

5. Pumps in heavy liquid service may be given an 85% reduction credit if monitored at 2,000 ppmv by permit condition provided that the concentration at saturation is greater than 2,000 ppmv.

6. Pumps in heavy liquid service may be given a 93% reduction credit if monitored at 500 ppmv by permit condition provided that the concentration at saturation is greater than 500 ppmv.

7. If an applicant decides to monitor their connectors using an organic vapor analyzer (OVA) at the same leak definition as valves, then the applicable valve credit may be used instead of the 30%. If this option is chosen, the company shall continue to perform the weekly physical inspections in addition to the quarterly OVA monitoring.

8. The 28 Series quarterly LDAR programs require open-ended lines to equipped with a cap, blind flange, plug, or a second valve. If so equipped, open-ended lines may be given a 100% control credit.

Sample Fugitive Emission Rate Calculations
Chemical Plant Implementing the 28VHP LDAR Program

Component Name	Stream Type	Number of Components	SOCMI w/o C_2 Emission Factors	LDAR Program	Control Efficiency	Controlled Emission Rates	
						Lbs/Hour	Tons/Year
Valves	Gas/Vapor	1,019	0.0089	28VHP	97%	0.27	1.19
Valves	Light Liquid	2,263	0.0035	28VHP	97%	0.24	1.04
Pumps	Light Liquid	14	0.0386	28VHP	85%	0.08	0.36
Connectors	Gas/Vapor	1,435	0.0029	28VHP	97% *	0.12	0.55
Connectors	Light Liquid	3,056	0.0005	28VHP	97% *	0.05	0.20
Compressors	Gas/Vapor	1	0.5027	28VHP	85%	0.08	0.33
Relief Valves	Gas/Vapor	12	0.2293	28VHP	100% †	0.00	0.00
Open-Ended Lines	Gas/Vapor	3	0.0040	28VHP	100% ††	0.00	0.00
Total Fugitive Emission Rates						**0.84**	**3.67**

* Flanges monitored at 500 ppmv; therefore, the valve control credit is applied.

† Relief valves routed to a flare; therefore, 100% control credit is applied.

†† The 28 Series LDAR Programs require open-ended lines to equipped with a cap, blind flange, plug, or a second valve for 100% control credit. The connector count is increased by the number of open-ended lines to account for the credit.

Fugitive Emission Speciation for Sample Calculations

Chemical Name	Weight Percent in Stream	Controlled Fugitive	
		Lbs/Hour	Tons/Year
Propane	4%	0.03	0.15
Benzene	7%	0.06	0.26
Toluene	62%	0.52	2.28
Xylene	8%	0.07	0.29
Ethylbenzene	17%	0.14	0.62
Hydrogen Sulfide *	2%	0.02	0.07
Total VOC	98%	0.82	3.60
Hydrogen Sulfide *	2%	0.02	0.07

* Calculation method assumes that the maximum off-property impact will not exceed ESL or Regulation II limits for H_2S. See Section II, Odorous/Inorganic Compounds, and Section III, Audio/Visual/Olfactory Walk-Through Inspection, for additional information.

Appendix B

GHG BACT CONTROLS AND EMISSION LIMITS FOR PROCESS HEATERS

Appendix B: GHG BACT Controls and Emission Limits for Process Heaters

This Appendix provides support for the BACT determination made by FHR for process heaters. Where available, a link to the applicable document is provided.

First, the following table summarizes the available BACT determinations for process heaters that are discussed in EPA guidance documents.

Guidance Document	Control Technology
EPA Office of Air and Radiation, "Available And Emerging Technologies For Reducing Greenhouse Gas Emissions From The Petroleum Refining Industry" (October 2010).	Energy Efficient Design: • In general, this document recommends improving process monitoring and control systems; using high efficiency motors; and using variable speed drives. Pp. 19-21. • For process heaters in particular, it recommends using combustion air controls to maintain limits on excess air, and using flue gases to preheat combustion air. P. 24.
EPA Office of Air Quality Planning and Standards, "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011).	This guidance document is not specific to a particular type of facility or emission unit. However, it does provide some considerations and examples applicable to the control technologies identified in FHR's GHG BACT analysis for the process heaters. Energy Efficient Design: • Use of technologies or processes that maximize the energy efficiency of the individual emissions unit. P. 29 • Use of technologies that improve the utilization of thermal energy that is generated and used on site, concentrating on the energy efficiency of equipment that uses the largest amounts of energy. Pp. 30-31 Carbon Capture and Storage: According to EPA, CCS is available as a BACT control technology for "facilities emitting CO2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)." P. 32. The process heaters at the West Refinery do not fit any of the above categories, so FHR has excluded CCS as an "available" control technology for purposes of identifying BACT.

Second, the following table summarizes both numeric emission limits reflecting BACT for GHG issued by permitting authorities in final or draft PSD permits for process heaters, and controls and emission limits proposed by permit applicants. All of the draft and final permits identified below contain emission limits and do not impose specific control technologies. We reviewed the permit applications and supporting documents for these permits, and we set forth below the control technologies the permitting authorities considered in setting the numeric emission limits. These are the same technologies that FHR has considered in its application. We set forth the status of the permit and the documents reviewed for each facility in parentheses next to the facility name.

Facility (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
Hyperion Energy Center (Final PSD permit)	Process Heaters (refinery fuel gas)	None specified		• 33.0 tons CO2e per thousand barrels of crude oil received
Sinclair Wyoming Refinery (Draft PSD permit and Statement of Basis)	Process Heaters (refinery fuel gas and natural gas)	Energy Efficient Design	• Combustion air preheat • Use of process heat to generate steam • Process integration and heat recovery • Use of excess combustion air monitoring and control	• 146 lb CO2e/MMBtu • [Various] ton CO2e/yr

Facility (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
		Good Combustion Practices	• Good air/fuel mixing in the combustion zone • Sufficient residence time to complete combustion • Proper fuel gas supply system design and operation • Good burner maintenance and operation • High temperatures and low oxygen levels in the primary combustion zone • Maintaining overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency	
Valero McKee Refinery – Diamond Shamrock Company (PSD permit application)	Vacuum Heater (refinery fuel gas and natural gas)	Energy Efficient Design	• Combustion air preheat • Use of process heat to generate steam • Process integration and heat recovery • Increase radiant tube surface area when modifying existing heaters • Excess combustion air monitoring and control	None

Facility (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
		Good Combustion Practices	• Good air/fuel mixing in the combustion zone • Sufficient residence time to complete combustion • Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality • Good burner maintenance and operation • High temperatures and low oxygen levels in the primary combustion zone • Overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency	
Energy Transfer Partners - Lone Star NGL Mont Belvieu Gas Plant (PSD permit application and final permit)	Hot Oil Heaters and Molecular Sieve Regenerator Heaters (natural gas)	Energy Efficient Design	• Combustion air controls – limitations on excess air • Efficient heater and burner design, which improves the mixing of fuel via intelligent flame ignition, flame intensity controls, and flue gas recirculation optimization • Heat recovery using heat exchangers	Hot Oil Heater (per unit): • 138,078 tpy CO_2e • 2,759 lb CO_2/bbl of NGL processed Molecular Sieve Regenerator Heater (per unit): • 23,524 tpy CO_2e • 470 lb CO_2/bbl of NGL processed
		Proper Operation and Good Combustion Practices	• Periodic tune-ups and maintenance • Providing the proper air-to-fuel ratio, residence time, temperature, and combustion zone turbulence • Developing systems for operator practices, maintenance knowledge, and maintenance practices	
Freeport LNG Development,	Process Heaters (natural gas)	Energy Efficient Design	• Improved fuel mixing to create a more efficient heat transfer	None

Facility (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
Liquefaction Plant (PSD permit application)		Good Combustion Practices	• Proper maintenance and tune-up of the process heaters at least annually per the manufacturer's specifications.	
PL Propylene LLC (PSD permit application)	Charge Gas Heater and Regeneration Air Heater (natural gas)	Energy Efficient Design	• Heat loss reduction using rigid or blanket insulation • Digital control system to control the heater's operations, including the fuel/air feed and burner operations	None
		Good Combustion Practices	• Periodic burner tuning using the three basic maintenance levels: combustion inspections; hot gas path inspections; and major overhauls	
Targa Gas Processing, Longhorn Gas Plant (revised PSD permit application)	Glycol Reboiler, Regeneration Heater, and Hot Oil Heater (natural gas)	Energy Efficient Design	• Optimize combustion efficiency by ensuring proper air-to-fuel ratio to create more efficient heat transfer.	Annual limits: Glycol Reboiler: • 1,025 tpy CO2e Regen Heater: • 6,355 tpy CO2e Hot Oil Heater: • 50,223 tpy CO2e Output-based limit: 1,783.23 lbs CO2/MMscf (combined limit for the 3 units)
		Good Combustion Practices	• Proper maintenance and tune-up of the process heaters at least annually per the manufacturer's specifications.	

Facility (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
KM Liquids Terminals (PSD permit application)	Heaters (natural gas)	Energy Efficient Design	• Use of oxygen monitors and intake air flow monitors to optimize the fuel/air mixture and limit excess air. • Variable speed electric motors are being utilized on air coolers to reduce electrical running load. • Larger electric drivers for centrifugal pumps are reduced in size by providing multiple parallel pump units that can be shut down when product rates are reduced. • Hot bottoms from the main distillation column are re-circulated through the stripper columns as a heating media for the column reboilers, which is then circulated through the furnace convection section to recover waste heat from furnace stack effluent. • Hot oil is used in a separate furnace to supply heat at a lower temperature to the process to reduce furnace stack gas temperature and, thereby, increase furnace efficiency.	
		Good Combustion Practices	• Periodic burner tune-up. • Good fuel/air mixing in the combustion zone • Limiting the excess air enhances efficiency and reduces emissions through reduction of the volume of air that needs to be heated in the combustion process; • Proper fuel gas supply system design and operation.	

<table>
<tr><th>Facility (reviewed document(s))</th><th>Emission Unit (fuel type)</th><th colspan="2">Control Technology</th><th>Emission Limits</th></tr>
<tr><td rowspan="2">Alcoa Davenport Works (Draft PSD permit and Technical Support Document)</td><td rowspan="2">Process Heaters (natural gas)</td><td>Energy Efficient Design</td><td>• Flue gas heat recovery/Economizer
• Improved instrumentation and controls</td><td rowspan="2">• 117 lb CO2/MMBtu
• 30,270.2 tpy CO2e</td></tr>
<tr><td>Good Combustion Practices</td><td>• Combustion control optimization
• Periodic equipment tuning
• Workplace manual detailing efficiency improvements</td></tr>
</table>

Appendix C

MSS SPECIAL CONDITIONS 82-90, 93 FROM TCEQ NSR PERMIT NO. 8803A

82. This permit authorizes the emissions from the facilities authorized by this permit for the planned maintenance, startup, and shutdown (MSS) activities summarized in the MSS Activity Summary (Attachment C) attached to this permit.

This permit authorizes emissions from the following temporary facilities used to support planned MSS activities at permanent site facilities: frac tanks, containers, vacuum trucks, facilities used for abrasive blasting, portable control devices identified in Special Condition 93, and controlled recovery systems. Emissions from temporary facilities are authorized provided the temporary facility (a) does not remain on the plant site for more than 12 consecutive months, (b) is used solely to support planned MSS activities at the permanent site facilities authorized by this permit, and (c) does not operate as a replacement for an existing authorized facility.

Attachment A identifies the inherently low emitting MSS activities that may be performed at the refinery. Emissions from activities identified in Attachment A shall be considered to be equal to the potential to emit represented in the permit application. The estimated emissions from the activities listed in Attachment A must be revalidated annually. This revalidation shall consist of the estimated emissions for each type of activity and the basis for that emission estimate.

Routine maintenance activities, as identified in Attachment B may be tracked through the work orders or equivalent. Emissions from activities identified in Attachment B shall be calculated using the number of work orders or equivalent that month and the emissions associated with that activity identified in the permit application.

The performance of each planned MSS activity not identified in Attachments A or B and the emissions associated with it shall be recorded and include at least the following information:

A. the physical location at which emissions from the MSS activity occurred, including the emission point number and common name for the point at which the emissions were released into the atmosphere;

B. the type of planned MSS activity and the reason for the planned activity;

C. the common name and the facility identification number, if applicable, of the facilities at which the MSS activity and emissions occurred;

D. the date of the MSS activity and its duration; and

E. the estimated quantity of each air contaminant, or mixture of air contaminants, emitted with the data and methods used to determine it. The emissions shall be estimated using the methods identified in the permit application, consistent with good engineering practice.

All MSS emissions shall be summed monthly and the rolling 12-month emissions shall be updated on a monthly basis.

83. Process units and facilities, with the exception of those identified in Special Conditions 86, 87, 89, and Attachment A shall be depressurized, emptied, degassed, and placed in service in accordance with the following requirements.

A. The process equipment shall be depressurized to a control device or a controlled recovery system prior to venting to atmosphere, degassing, or draining liquid. Equipment that only contains material that is liquid with VOC partial pressure less than 0.50 psi at the normal process temperature and 95°F may be opened to atmosphere and drained in accordance with paragraph C of this special condition. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded.

B. If mixed phase materials must be removed from process equipment, the cleared material shall be routed to a knockout drum or equivalent to allow for managed initial phase separation. If the VOC partial pressure is greater than 0.50 psi at either the normal process temperature or 95°F, any vents in the system must be routed to a control device or a controlled recovery system. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded. Control must remain in place until degassing has been completed or the system is no longer vented to atmosphere.

C. All liquids from process equipment or storage vessels must be removed to the maximum extent practical prior to opening equipment to commence degassing and/or maintenance. Liquids must be drained into a closed vessel unless prevented by the physical configuration of the equipment. If it is necessary to drain liquid into an open pan or sump, the liquid must be covered or transferred to a covered vessel within one hour of being drained. After draining is complete, empty open pans may remain in use for housekeeping reasons to collect incidental drips.

D. If the VOC partial pressure is greater than 0.50 psi at the normal process temperature or 95°F, facilities shall be degassed using good engineering practice to ensure air contaminants are removed from the system through the control device or controlled recovery system to the extent allowed by process equipment or storage vessel design. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded. The control device or recovery system utilized shall be recorded with the estimated emissions from controlled and uncontrolled degassing calculated using the methods that were used to determine allowable emissions for the permit application.

The following requirements do not apply to fugitive components, pumps, and compressors.

(1) For MSS activities identified in Attachment B, the following option may be used in lieu of (2) below. The facilities being prepared for maintenance shall not be vented directly to atmosphere, except as necessary to verify an acceptable VOC concentration and establish isolation of the work area, until the VOC concentration has been verified to be less than 10 percent of the lower explosive limit (LEL) per the site safety procedures. (11/11)

(2) The locations and/or identifiers where the purge gas or steam enters the process equipment or storage vessel and the exit points for the exhaust gases shall be recorded. PFD's or P&ID's may be used to demonstrate compliance with the requirement. Documented refinery procedures used to deinventory equipment to a control device for safety purposes (i.e., hot work or vessel entry procedures) that achieve at least the same level of purging may be used in lieu of the above. If the process equipment is purged with a gas, two system volumes of purge gas must have passed through the control device or controlled recovery system before the vent stream may be sampled to verify

acceptable VOC concentration prior to uncontrolled venting. The VOC sampling and analysis shall be performed using an instrument meeting the requirements of Special Condition 84. The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into the sample probe or the collection system downstream of the process equipment or vessel being purged. The facilities shall be degassed to a control device or controlled recovery system until the VOC concentration is less than 10,000 ppmv or less than 10% of the lower explosive limit (LEL). (07/11)

E. Gases and vapors with VOC partial pressure greater than 0.50 psi may be vented directly to atmosphere if all the following criteria are met:

(1) It is not technically practicable to depressurize or degas, as applicable, into the process.

(2) There is not an available connection to a plant control system (flare).

(3) There is no more than 50 lbs of air contaminant to be vented to atmosphere during shutdown or startup, as applicable.

All instances of venting directly to atmosphere per Special Condition 83.E must be documented when occurring as part of any MSS activity. The emissions associated with venting without control must be included in the work order, shift log, or equivalent for those planned MSS activities identified in Attachment B.

84. Air contaminant concentration shall be measured using an instrument/detector meeting one set of requirements specified below.

A. VOC concentration shall be measured using an instrument meeting all the requirements specified in EPA Method 21 (40 C.F.R. Part 60, Appendix A) with the following exceptions:

(1) The instrument shall be calibrated within 24 hours of use with a calibration gas such that the response factor of the VOC (or mixture of VOCs) to be monitored shall be less than 2.0. The calibration gas and the gas to be measured, and its approximate response factor shall be recorded.

(2) Sampling shall be performed as directed by this permit in lieu of section 8.3 of Method 21. During sampling, data recording shall not begin until after two times the instrument response time. The date and time shall be recorded, and VOC concentration shall be monitored for at least 5 minutes and the highest concentration recorded. The highest measured VOC concentration shall not exceed the specified VOC concentration limit prior to uncontrolled venting.

(3) If a TVA-1000 series FID analyzer calibrated with methane is used to determine the VOC concentration, a measured concentration of 34,000 ppmv may be considered equivalent to 10,000 ppmv as VOC.

B. Colorimetric gas detector tubes may be used to determine air contaminant concentrations if they are used in accordance with the following requirements.

(1) The air contaminant concentration measured is less than 80 percent of the range of the tube. If the maximum range of the tube is greater than the release concentration defined in 3, the concentration measured is at least 20 percent of the maximum range of the tube.

(2) The tube is used in accordance with the manufacturer's guidelines.

(3) At least 2 samples taken at least 5 minutes apart must satisfy the following prior to uncontrolled venting:

measured contaminant concentration (ppmv) < release concentration.

Where the release concentration is:

10,000*mole fraction of the total air contaminants present that can be detected by the tube.

The mole fraction may be estimated based on process knowledge. The release concentration and basis for its determination shall be recorded.

Records shall be maintained of the tube type, range, measured concentrations, and time the samples were taken.

C. Lower explosive limit measured with an MSA Sirius lower explosive limit detector.

(1) The detector shall be calibrated monthly with a certified pentane calibration gas equivalent to 58 percent of the lower explosive limit (LEL) for pentane. Records of the calibration date/time and calibration result (pass/fail) shall be maintained. (04/11)

(2) A daily functionality test shall be performed on each detector using the same certified gas standard used for calibration. The LEL monitor shall read no lower than 90 percent of the calibration gas certified value. Records, including the date/time and test results, shall be maintained.

(3) A certified methane gas standard equivalent to 29 percent of the LEL for methane may be used for calibration and functionality tests provided that the LEL response is within 95 percent of that for pentane. (04/11)

(4) For any test environments in which pentane is not present in the sources tested, a determination shall be documented and maintained on site that the monitor as calibrated with the pentane stimulant gas will provide conservatively accurate results and is a sensitive monitor for the components in question to set the decision to allow uncontrolled release of VOC to the atmosphere. Otherwise, an alternative monitoring approach must be used. (04/11)

(5) The facility may submit a request for a determination that additional LEL detectors, which provide conservatively accurate results and are sensitive for the components in question, may be used. The permit holder shall obtain approval from the TCEQ prior to using a different LEL detector. (11/11)

85. If the removal of a component for repair or replacement results in an open ended line or valve, the open ended line is exempt from any NSR permit condition requirement to install a cap,

blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period:

A. A cap, blind flange, plug, or second valve must be installed on the line or valve, or demonstrate that the line, valve, component, etc., has been double blocked from the process; or

B. The permit holder shall verify that there is no leakage from the open-ended line or valve. The open-ended line or valve shall be monitored on a weekly basis in accordance with the applicable NSR permit condition for fugitive emission monitoring except that a leak is defined as any VOC reading greater than background. Leaks must be repaired no later than one calendar day after the leak is detected or a cap, blind flange, plug, or second valve must be installed on the line or valve. The results of this weekly check and any corrective actions taken shall be recorded.

86. This permit authorizes emissions for the storage tanks identified in the attached facility list during planned floating roof landings. Unless the tank vapor space is routed to a control device meeting the requirements of Special Condition 93, tank roofs may only be landed for changes of tank service or tank inspection/maintenance as identified in the permit application. Emissions from change of service tank landings shall not exceed 10 tons of VOC in any rolling 12 month period. Tank roof landings include all operations when the tank floating roof is on its supporting legs. These emissions are subject to the maximum allowable emission rates indicated on the Emission Sources, Emissions Caps and Individual Emission Limitations Table. The following requirements apply to tank roof landings.

A. The tank liquid level shall be continuously lowered after the tank floating roof initially lands on its supporting legs until the tank has been drained to the maximum extent practicable without entering the tank. Liquid level may be maintained steady for a period of up to three hours if necessary to allow for valve lineups and pump changes necessary to drain the tank. This requirement does not apply where the vapor under a floating roof is routed to control or a controlled recovery system during this process.

This requirement does not apply if the level is lowered to allow for maintenance that is expected to be completed in less than 24 hours. In that case, the tank must be filled and the roof floated within 24 hours of landing the roof and the evolution documented in accordance with Special Condition 86.E.

B. If the VOC partial pressure of the liquid previously stored in the tank is greater than 0.50 psi at 95°F, tank refilling or degassing of the vapor space under the landed floating roof must begin within 24 hours after the tank has been drained unless the vapor under the floating roof is routed to control or a controlled recovery system during this period. Floating roof tanks with liquid capacities less than 100,000 gallons may be degassed without control if the VOC partial pressure of the standing liquid in the tank has been reduced to less than 0.02 psia prior to ventilating the tank. Controlled degassing of the vapor space under landed roofs shall be completed as follows:

(1) Any gas or vapor removed from the vapor space under the floating roof must be routed to a control device or a controlled recovery system and controlled degassing must be maintained until the VOC concentration is less than 10,000 ppmv or less than 10 percent of the LEL. The locations and identifiers of vents other than permanent roof fittings and seals, control device or controlled recovery system, and controlled exhaust stream shall be recorded.

There shall be no other gas/vapor flow out of the vapor space under the floating roof when degassing to the control device or controlled recovery system.

(2) The vapor space under the floating roof shall be vented using good engineering practice to ensure air contaminants are flushed out of the tank through the control device or controlled recovery system to the extent allowed by the storage tank design until the VOC concentration is less than 10,000 ppmv or 10% of the LEL.

(3) A volume of gas equivalent to twice the volume of the vapor space under the floating roof must have passed through the control device or into a controlled recovery system, before the vent stream may be sampled to verify acceptable VOC concentration. The measurement of the gas volume shall not include any make-up air introduced into the control device or recovery system. Documented refinery procedures used to de-inventory equipment to a control device for safety purposes (i.e., hot work or vessel entry procedures) that achieve at least the same level of purging may be used in lieu of the above. The VOC sampling and analysis shall be performed as specified in Special Condition 84.

(4) The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into the sample probe or the collection system downstream of the process equipment or vessel being purged.

(5) If ventilation is to be maintained with emission control, the control device shall be monitored in accordance with Special Condition 93.

Degassing must be performed every 24 hours unless there is no standing liquid in the tank or the VOC partial pressure of the remaining liquid in the tank is less than 0.15 psia.

C. The tank shall not be opened except as necessary to set up for degassing and cleaning, or ventilated without control, until either all standing liquid has been removed from the tank or the liquid in the tank has a VOC partial pressure less than 0.02 psia. These criteria may be demonstrated in any one of the following ways.

(1) Low VOC partial pressure liquid that is soluble with the liquid previously stored may be added to the tank to lower the VOC partial pressure of the liquid mixture remaining in the tank to less than 0.02 psia. This liquid shall be added during tank degassing if practicable. The estimated volume of liquid remaining in the drained tank and the volume and type of liquid added shall be recorded. The liquid VOC partial pressure may be estimated based on this information and engineering calculations.

(2) If water or other liquid is added or sprayed into the tank to remove standing VOC, acceptable vapor pressure may be demonstrated using any of the three methods below:

(a) Take a representative sample of the liquid remaining in the tank and verify no visible sheen using the static sheen test from 40 C.F.R. 435 Subpart A, Appendix 1.

(b) Take a representative sample of the liquid remaining in the tank and verify hexane soluble VOC concentration is less than 1000 ppmw using EPA Method 1664 (may also use 8260B or 5030 with 8015 from SW-846).

(c) Stop ventilation and close the tank for at least 24 hours. When the tank manway is opened after this period, verify VOC concentration is less than 1000 ppmv through the procedure in Special Condition 84.

(3) No standing liquid verified through visual inspection.

Once the VOC partial pressure is verified less than 0.02 psia, any subsequent/additional water flushes that may be performed do not trigger additional verification. The permit holder shall maintain records to document the method used to release the tank.

D. Tanks shall be refilled as rapidly as practicable until the roof is off its legs with the following exceptions:

(1) The vapor space under the floating roof is routed to control during refilling.

(2) The fill rate shall not exceed 3000 barrels per hour (bbl/hr) for any tank.

E. The occurrence of each roof landing and the associated emissions shall be recorded and the rolling 12-month tank roof landing emissions shall be updated on a monthly basis.

These records shall include at least the following information:

(1) the identification of the tank and emission point number, and any control devices or recovery systems used to reduce emissions;

(2) the reason for the tank roof landing;

(3) for the purpose of estimating emissions, the date, time and other information specified for each of the following events:

(a) the roof was initially landed,

(b) all liquid was pumped from the tank to the extent practical,

(c) start and completion of controlled degassing, and total volumetric flow,

(d) all standing liquid was removed from the tank or any transfers of low VOC partial pressure liquid to or from the tank including volumes and vapor pressures to reduce tank liquid VOC partial pressure to <0.02 psi,

(e) if there is liquid in the tank, VOC partial pressure of liquid, start and completion of uncontrolled degassing, and total volumetric flow,

(f) refilling commenced, liquid filling the tank, and volume necessary to float the roof, and

(g) tank roof off supporting legs, floating on liquid.

(4) the estimated quantity of each air contaminant, or mixture of air contaminants, emitted between Events C and G with the data and methods used to determine it. The emissions associated with roof landing activities shall be calculated using the methods described in Section 7.1.3.2 of AP-42 "Compilation of Air Pollution Emission Factors, Chapter 7 - Storage of Organic Liquids" dated November 2006 and the permit application.

87. Fixed roof tanks shall not be ventilated without control, until either all standing liquid has been removed from the tank or the liquid in the tank has a VOC partial pressure less than 0.02 psia. This shall be verified and documented through one of the criteria identified in Special Condition 86.C. Fixed roof tanks manways may be opened without emission controls when there is standing liquid with a VOC partial pressure greater than 0.02 psi vapor as necessary to set up for degassing and cleaning. One manway may be opened when necessary to allow access to the tank to remove or de-volatilize the remaining liquid. The emission control system shall meet the requirements of Special Condition 86.B.(1) through 86.B.(5) and records maintained per Special Condition 86.E.(3)c through 86.E.(3)e, and 86.E.(4) Low vapor pressure liquid may be added to and removed from the tank as necessary to lower the vapor pressure of the liquid mixture remaining in the tank to less than 0.02 psia.

88. The following requirements apply to vacuum and air mover truck operations to support planned MSS at this site:

A. Vacuum pumps and blowers shall not be operated on trucks containing or vacuuming liquids with VOC partial pressure greater than 0.50 psi at 95°F unless the vacuum/blower exhaust is routed to a control device or a controlled recovery system.

B. When the vacuum pump is operating, equip fill line intake with a “duckbill” or equivalent attachment if the hose end cannot be submerged in the liquid being collected.

C. A daily record containing the information identified below is required for each vacuum truck in operation at the site each day.

(1) Prior to initial use, identify any liquid in the truck. Record the liquid level and document that the VOC partial pressure is less than 0.50 psi if the vacuum exhaust is not routed to a control device or a controlled recovery system. After each liquid transfer, identify the liquid transferred and document that the VOC partial pressure is less than 0.50 psi if the vacuum exhaust is not routed to a control device or a controlled recovery system.

(2) For each liquid transfer made with the vacuum operating, record the duration of any periods when air may have been entrained with the liquid transfer. The reason for operating in this manner and whether a “duckbill” or equivalent was used shall be recorded. Short, incidental periods, such as those necessary to walk from the truck to the fill line intake, do not need to be documented.

(3) If the vacuum truck exhaust is controlled by a device other than an engine or oxidizer, VOC exhaust concentration shall be measured using an instrument meeting the requirements of Special Condition 84 upon commencing each transfer, at the end of each transfer, and as required by Special Condition 93 during each transfer.

(4) The volume in the vacuum truck at the end of the day, or the volume unloaded, as applicable.

D. The permit holder shall determine the vacuum truck emissions each month using the daily vacuum truck records and the calculation methods utilized in the permit application. If records of the volume of liquid transferred for each uncontrolled vacuum truck pick-up are not maintained, the emissions shall be determined using the physical properties of the liquid vacuumed with the greatest potential emissions. Rolling 12 month vacuum truck emissions shall also be determined on a monthly basis.

E. If the VOC partial pressure of all the liquids vacuumed into the truck is less than 0.10 psi, this shall be recorded when the truck is unloaded or leaves the plant site and the emissions may be estimated as the maximum potential to emit for a truck in that service as documented in the permit application. The recordkeeping requirements in Special Condition 88.A through 88.D do not apply.

89. The following requirements apply to frac, or temporary, tanks and vessels used in support of MSS activities.

A. Except for labels, logos, etc. not to exceed 15 percent of the tank/vessel total surface area, the exterior surfaces of these tanks/vessels that are exposed to the sun shall be white or aluminum effective May 1, 2013. This requirement does not apply to tanks/vessels that only vent to atmosphere when being filled.

B. These tanks/vessels must be covered and equipped with fill pipes that discharge within 6 inches of the tank/vessel bottom. If the VOC partial pressure of the liquid in the tank is greater than 0.5 psi at 95°F, the tanks vents must be routed to a control device or controlled recovery system when the tank is being filled.

C. These requirements do not apply to vessels storing less than 100 gallons of liquid that are closed such that the vessel does not vent to atmosphere.

D. The permit holder shall maintain an emissions record which includes calculated emissions of VOC from all frac tanks during the previous calendar month and the past consecutive 12 month period. The record shall include tank identification number, dates put into and removed from service, control method used, tank capacity and volume of liquid stored in gallons, name of the material stored, VOC molecular weight, and VOC partial pressure at the estimated monthly average material temperature in psia. Filling emissions for tanks shall be calculated using the TCEQ publication titled "Technical Guidance Package for Chemical Sources - Loading Operations" and standing emissions determined using: the TCEQ publication titled "Technical Guidance Package for Chemical Sources - Storage Tanks."

E. If the tank/vessel is used to store liquid with VOC partial pressure less than 0.10 psi at 95°F, records may be limited to the days the tank is in service and the liquid stored. Emissions may be estimated based upon the potential to emit as identified in the permit application.

90. The following requirements apply to tank MSS activities to ensure acceptable off-site impacts.

A. Tank MSS emissions activities include tank degassing, tank opening, tank refilling following a degassing/cleaning until the roof is floated, and tank refilling not following a degassing/cleaning until the roof is floated. Only one of each type of activity may occur at any time for any liquid type (crude oil, benzene, lights, and distillates) at the site. Different tank MSS emissions activities may occur concurrently.

B. All emissions from tanks with landed roofs being filled with product grade benzene shall be routed to a control device meeting the requirements of Special Condition 93 unless the tank has been cleaned, degassed, and is at least 1650 feet from the property line. All emissions from tanks with landed roofs being filled with reformate shall be routed to a control device meeting the requirements of Special Condition 93 unless the tank has been cleaned, degassed, and is at least 1,300 feet from the property line. For benzene and reformate tanks, a refill following a tank degassing and a refill not following a tank degassing will not occur at the same time unless the emissions from both are controlled.

C. The MSS emissions from the SRU Incinerators and emissions from controlled tank refills not following a tank degassing/cleaning at Tanks FB511, FB512, FB513, or FB514 cannot occur at the same time if the material in the tank produces a hydrogen sulfide head space concentration of greater than 50 ppmv.

D. Emissions from tanks with landed roofs being filled with liquids that generate hydrogen sulfide concentrations greater than 10 ppmv in the landed roof headspace (crude oil, sour water and sour intermediates) shall be routed to a control device meeting the requirements of Special Condition 93. The following applies to tanks within 750 feet of the property line that may have a hydrogen sulfide head space concentration greater than 50 ppmv.

(1) If filling a tank with a landed roof not following a tank degassing/cleaning, the fill rate will be lowered so that the hourly sulfur dioxide emission rate is at or below 4.44 lb/hr.

(2) Degassing of these tanks shall not occur while controlling the filling one of these tank that had not been degassed and cleaned.

E. The permit holder shall determine the potential hydrogen sulfide generated during tank refilling as reference in parts C and D of this condition by sampling the vapors when the liquid level is at approximately half the height of the landed roof and when the liquid level is within 10 percent of the height of the landed roof. The sampling shall be performed in accordance with Special Condition 84.B with the exception of 84.B.(3) This determination shall be made at least once for each type of liquid.

93. Control devices required by this permit for emissions from planned MSS activities are limited to those types identified in this condition. Control devices shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours.

Each device used must meet all the requirements identified for that type of control device.

Controlled recovery systems identified in this permit shall be directed to an operating refinery process or to a collection system that is vented through a control device meeting the requirements of this permit condition.

A. Carbon Adsorption System (CAS):

(1) The CAS shall consist of 2 carbon canisters in series with adequate carbon supply for the emission control operation.

(2) The CAS shall be sampled downstream on the first can and the concentration recorded at least once every hour of CAS run time to determine breakthrough of the VOC. The sampling frequency may be extended using either of the following methods:

(a) It may be extended to up to 30 percent of the minimum potential saturation time for a new can of carbon. The permit holder shall maintain records including the calculations performed to determine the minimum saturation time.

(b) The carbon sampling frequency may be extended to longer periods based on previous experience with carbon control of a MSS waste gas stream. The past experience must be with the same VOC, type of facility, and MSS activity. The basis for the sampling frequency shall be recorded. If breakthrough is monitored on the initial sample of the upstream can when the polishing can is put in place, a permit deviation shall be recorded.

(3) The method of VOC sampling and analysis shall be by detector meeting the requirements of Special Condition 84.

(4) Breakthrough is defined as the highest measured VOC concentration at or exceeding 100 ppmv above background. When the condition of breakthrough of VOC from the initial saturation canister occurs, the waste gas flow shall be switched to the second canister and a fresh canister shall be placed as the new final polishing canister within four hours or prior to the next required sample, whichever is greater. In lieu of replacing canisters, the flow of waste gas may be discontinued until the canisters are switched. Sufficient new activated carbon canisters shall be maintained at the site to replace spent carbon canisters such that replacements can be done in the above specified time frame.

(5) Records of CAS monitoring shall include the following:

(a) Sample time and date.

(b) Monitoring results (ppmv).

(c) Canister replacement log.

(6) Single canister systems are allowed if the time the carbon canister is in service is limited to no more than 30% of the minimum potential saturation time. The permit holder shall maintain records for these systems, including the calculations performed to determine the saturation time. The time limit on carbon canister service shall be recorded and the expiration date attached to the carbon can.

(7) Liquid scrubbers may be used upstream of carbon canisters to enhance VOC capture provided such systems are closed systems and the spent absorbing solution is discharged into a closed container, vessel, or system.

B. Thermal Oxidizer.

(1) The thermal oxidizer firebox exit temperature shall be maintained at not less than 1400°F and waste gas flows shall be limited to assure at least a 0.5 second residence time in the fire box while waste gas is being fed into the oxidizer.

(2) The thermal oxidizer exhaust temperature shall be continuously monitored and recorded when waste gas is directed to the oxidizer. The temperature measurements shall be made at intervals of six minutes or less and recorded at that frequency. Temperature measurements recorded in continuous strip charts may be used to meet the requirements of this section.

The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have an accuracy of the greater of ±0.75 percent of the temperature being measured expressed in degrees Celsius or ±2.5ºC.

C. Internal Combustion Engine.

(1) The internal combustion engine shall have a VOC destruction efficiency of at least 99 percent.

(2) The engine must have been stack tested with butane to confirm the required destruction efficiency within the past 12 months. VOC shall be measured in accordance with the applicable United States Environmental Protection Agency (EPA) Reference Method during the stack test and the exhaust flow rate may be determined from measured fuel flow rate and measured oxygen concentration. A copy of the stack test report shall be maintained with the engine. There shall also be documentation of acceptable VOC emissions following each occurrence of engine maintenance which may reasonably be expected to increase emissions including oxygen sensor replacement and catalyst cleaning or replacement. Stain tube indicators specifically designed to measure VOC concentration shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable VOC analyzers meeting the requirements of Special Condition 84 are also acceptable for this documentation.

(3) The engine shall be operated with an oxygen sensor-based air-to-fuel ratio (AFR) controller. Documentation for each AFR controller that the, manufacturer's, or supplier's recommended maintenance has been performed, including replacement of the oxygen sensor as necessary for oxygen sensor-based controllers shall be maintained with the engine. The oxygen sensor shall be replaced at least quarterly in the absence of a specific written recommendation.

D. The plant flare system operated per Special Condition 15.

With the exception of the MAERT emission limits, these permit conditions become effective on March 31, 2010. During this period, monitoring and recordkeeping shall satisfy the requirements of Special Condition 82. Emissions shall be estimated using good engineering practice and methods to provide reasonably accurate representations for emissions. The basis used for determining the quantity of air contaminants to be emitted shall be recorded.