Statement of Basis

Greenhouse Gas Prevention of Significant Deterioration (PSD) Preconstruction Permit for the Flint Hills Resources Corpus Christi, LLC – West Refinery

Permit Number: PSD-TX-6819A-GHG

April 2014

This document serves as the statement of basis for the above-referenced draft permit, as required by 40 Code of Federal Regulations (CFR) § 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR § 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On December 12, 2012, Flint Hills Resources Corpus Christi, LLC (FHR) submitted a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit application to the Environmental Protection Agency (EPA) Region 6 to authorize a modification at the FHR Corpus Christi West Refinery, an existing major source of criteria pollutants located in Corpus Christi, Nueces County, Texas. In conjunction with this GHG permit application, FHR also submitted a minor New Source Review (NSR) permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on December 12, 2012, for the same proposed modification. The TCEQ permit (No. 6819A) for this modification has not been issued yet. FHR submitted responses to EPA questions and updates to the GHG permit application and record on May 16, 2013; June 25, 2013; July 3, 2013; and throughout February and March 2014. FHR submitted a revised permit application, memorializing changes made in the responses, on March 27, 2014.

The proposed project at the FHR Corpus Christi West Refinery, the Domestic Crude Project (“Project”), would add and modify certain equipment to enable the facility to process a larger percentage of domestic (versus foreign) crude oil. Because domestic crude oil is much lighter than foreign crude oil, the Project includes construction of a new process unit and other equipment to process additional lighter-end products. Implementation of the Project would also increase the refinery’s capacity to process crude oil by approximately 7% through the new and modified equipment, increased utilization of existing equipment, and debottlenecking.

After reviewing the application, EPA Region 6 prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the FHR Corpus Christi West Refinery. This SOB documents the information and analysis EPA used to support its decisions made in drafting the air permit. The SOB includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the permitting requirements.

EPA Region 6 concludes that FHR's application is complete and provides the necessary information to demonstrate that the Project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information EPA requested that was provided by FHR, and EPA's own technical analysis. EPA is making all of this information available as part of the public record.

II. Applicant

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III. Permitting Authority

On May 3, 2011, EPA published a Federal Implementation Plan (FIP) that deems EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305). Texas still retains approval of its plan and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated New Source Review (NSR) pollutants other than GHGs.

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

Contact:
Kathleen Aisling
EPA, Region 6 Permit Writer
Air Permitting Section (6PD-R)
(214) 665-6406

Facility Location

The FHR Corpus Christi West Refinery is located in Corpus Christi, Nueces County, Texas. (See Figure 1.) The area is currently designated attainment/unclassified for all criteria pollutants.[1] The geographic coordinates for this facility are as follows:

Latitude: 27º 49’ 38” North;
Longitude: -97º 31’32” West

Figure 1. Flint Hills Resources, Corpus Christi West Refinery Location

[1] The criteria pollutants are carbon monoxide, lead, nitrogen dioxide, ozone, particulate matter (PM), and sulfur dioxide. EPA revised the annual National Ambient Air Quality Standards $PM_{2.5}$ standard in December 2012, but has not completed the designations. The attainment status for all Texas counties for $PM_{2.5}$ is listed as “pending.”

IV. Applicability of Prevention of Significant Deterioration Regulations

EPA concludes that FHR's application is subject to PSD review for GHGs because the Project would result in an emissions increase of GHGs for a facility as described at 40 CFR § 52.21(b)(49)(v)(*b*). If the Project is implemented, the FHR Corpus Christi West Refinery, an existing stationary source that has the potential to emit 100,000 tons per year (tpy) carbon dioxide equivalent (CO_2e), will undertake a physical change or change in the method of operation that will result in an emissions increase of 75,000 tpy CO_2e or more. FHR calculates that the total increase in emissions from new, modified, and existing non-modified units will be 359,991 tpy CO_2e while the emissions from new and modified units will be 299,884 tpy CO_2e.[2] EPA Region 6 implements the GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

The applicant represents that the Project will not trigger federal PSD for any non-GHG, NSR-regulated (criteria) pollutant and that it is only subject to Texas minor NSR requirements for these pollutants. At this time, TCEQ has not issued the minor NSR permit for the non-GHG pollutants.

EPA Region 6 applies the policies and practices reflected in the March 2011 EPA document "EPA-457/B-11-001: PSD and Title V Permitting Guidance for Greenhouse Gases" (GHG Permitting Guidance). Consistent with the GHG Permitting Guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, and we have not required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the selected Best Available Control Technology (BACT) is the best method of satisfying the additional impacts analysis and Class I area requirements of the rules as they relate to GHGs. As part of the minor NSR permitting for this project, TCEQ has reviewed FHR's modeling for $PM_{2.5}$ (particulate matter less than 2.5 microns), PM_{10} (particulate matter less than 10 microns), and nitrogen dioxide, and performed screening modeling for ammonia in the Selective Catalytic Reduction (SCR) technology added to the new and modified hot oil heaters.

For the purposes of PSD applicability, a source is required to look beyond the modified emission unit to determine the extent of emission increases that result from the modification. The GHG Permitting Guidance notes that emission increases from sources upstream and downstream of the modified emission unit must also be included in the determination of the total project emission increase. However, in the preamble for the 1980 rule that established the current version of 40 CFR § 52.21(j)(3), EPA explained that "BACT applies only to the units actually modified." See 45 FR 52676, 52681 (Aug.7, 1980).

[2] This number reflects the total emissions from the Project for new and modified units. The emissions increase from the Project for new and modified units is 279,400 tpy CO_2e which is 299,884 tpy CO_2e, minus the baseline emissions for the modified CCR Hot Oil Heater of 20,484 tpy CO_2e. The emission limits in the draft permit are based on the potential to emit for the CCR Hot Oil Heater, which is the total emissions (baseline, plus increase).

V. Project Description

The FHR Corpus Christi West Refinery processes crude oil and other raw materials to produce a variety of petroleum products, including low-sulfur gasoline, diesel, and jet fuel.

The proposed GHG PSD permit, if finalized, would allow FHR to add and modify certain pieces of equipment which would enable the facility to process a larger percentage of domestic crude oil. Because the domestic crude is much lighter than foreign crude, the project includes construction of an additional process unit and other equipment to process more lighter-end products. Implementation of the project would also increase the refinery's capacity to process crude oil by approximately 7% through the new equipment, increased utilization of existing equipment, and debottlenecking. The total emissions from new, modified, and existing non-modified units will be 359,991 tpy CO_2e while the emissions solely from new and modified units will be 299,884 tpy CO_2e.

Specifically, the changes at the existing FHR Corpus Christi West Refinery involve modification of equipment at the Continuous Catalytic Regeneration (CCR) Hot Oil Heater, which will increase heat input from 90 million British thermal units (MMBtu) per hour (hr) high heating value (HHV) to 123 MMBtu/hr (HHV), and the addition of a new Saturates Gas Plant (No. 3), which will contain a new hot oil heater with a maximum heat input rate of 450 MMBtu/hr (HHV). Both heaters will have new, energy efficient low nitrogen oxide (low-NO_x) burners, a new air preheat system and SCR for control of NO_x (non-GHG) emissions. Additionally, the Saturates Gas Plant No. 3 Hot Oil Heater will have a catalyst bed for control of carbon monoxide (CO) and volatile organic compounds (VOCs), both non-GHG emissions. Together, the two hot oil heaters will contribute 99.8% of the new CO_2e emissions for the project.

In addition, FHR will install a new Mid-Plant Cooling Tower (No. 2) and new equipment piping as part of the project. Installation of the new process vessels and two new storage tanks, which do not emit greenhouse gases during normal operations, will result in greenhouse gas emissions when maintenance activities are performed after purged vessels and equipment are opened to the atmosphere, and when maintenance emissions are routed to control devices that generate greenhouse gases. These maintenance emissions are listed as maintenance, startup, and shutdown (MSS) fugitive emissions in this SOB and in the permit.

Implementation of the project will also increase emissions at some units due to increased utilization or debottlenecking. The project will result in an increase in actual emissions due to increased utilization at Boilers 06BF657, 06BF658, 06BF659, and 43BF1; the API separator Flare; and the Marine Vapor Combustor; and an increase in actual emissions due to debottlenecking of the Distillate Hydrotreating Unit (DHT) Stripper Reboiler (part of the conversion of the Gas Oil Hydrotreating Unit to a DHT).

The project will also result in an increase in the annual marine loading throughput of naphtha and gasoline, and tank crude oil at tanks 08FB137, 08FB142, 08FB147, 40FB4010 and 40FB4011.

FHR submitted a separate minor NSR permit application to TCEQ that addressed the increased throughputs and includes a State BACT analysis for the marine loading and the crude oil tanks, 40FB4010 and 40FB4011.
EPA Region 6 further evaluated the proposed increased utilization of Boilers 06BF657, 06BF658, 06BF659, and 43BF1 ("the Utility Boilers") to ensure that these units would not have a change in the method of operation or exceed current TCEQ permit limits or representations made during permitting. FHR states that the Utility Boilers supplement the refinery's base steam needs, which are provided by the other boilers at the facility, the Cogeneration Waste Heat Recovery Boiler and the CO Boiler. FHR also states that the Utility Boilers have not been run at their maximum firing capacity (used to establish TCEQ emission rate limits) in the past and that no physical changes or changes to the method of operation of the boilers will be required for the boilers to meet the incremental steam demand increase for the Project.

Table 1, FHR Corpus Christi West Refinery Average Utility Boiler Firing Rates, provided by FHR, shows the highest average monthly firing rate and the average monthly firing rate for each utility boiler during the two-year baseline period used for calculations in this permit. In a February 17, 2014, response to an EPA request for additional information, FHR represented that the increase in steam demand (and resulting heat duty increase of 96 MMBtu/hr) could be provided by any one of the utility boilers; however, EPA notes that this is only the case for Boilers 7, 8, or 9 if that boiler is running below its monthly average firing rate. EPA agrees, however, that based on the information in Table 1, the four boilers together, or a combination of the boilers, appear to be able to accommodate the increase in heat duty required by the project without exceeding permitted limits, and thus, the increased firing of these boilers is not a change in the method of operation.

Table 1. FHR Corpus Christi West Refinery Average Utility Boiler Firing Rates

Emission Unit	Maximum Permitted Firing Capacity (MMBtu/hr)	2011-2012 Highest Monthly Average Firing Rate (MMBTU/hr)	2011-2012 Average Monthly Firing Rate (MMBTU/hr)
Boiler No. 7 (06BF657)	205	138	117
Boiler No. 8 (06BF658)	205	143	113
Boiler No. 9 (06BF659)	205	141	112
Mid Crude Boiler (43BF1)	221.5	125	97
Total	**836.5**	**547**	**439**

The existing units that are affected by the Domestic Crude Project permit are permitted through TCEQ permit No. 8803A. The new, modified, and downstream affected units (except for the utility boilers) in this PSD GHG permit will be permitted through TCEQ Permit

No. 6819A, once it is issued. The utility boilers will continue to be permitted through TCEQ Permit No. 8803A. EPA notes that some of the assumptions that are a part of the Potential to Emit calculations for the units regulated through this GHG permit are included in the historical permit applications for TCEQ Permit No. 8803A. In addition, because TCEQ permit No. 6819A is not yet issued for the Domestic Crude Project, this SOB references provisions from TCEQ permit No. 8803A, which will be moved to TCEQ permit No. 6819A, once it is finalized.

VI. Format of the BACT Analysis

The BACT analyses were conducted for new and modified units in accordance with the GHG Permitting Guidance, which outlines the steps for conducting a top-down BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control options;
(4) Evaluate the most effective controls and document the results; and,
(5) Select BACT.

Also, in accordance with the Greenhouse Gas Permitting Guidance, BACT analyses must take into account the energy, environmental, and economic impacts of the control options. Emission reductions may be achieved through the application of available control techniques, process design, and/or operational limitations.

VII. Applicable Emission Units and BACT Discussion

Table 2 shows the equipment that is a new or modified source, subject to this GHG PSD permit.

Table 2. Domestic Crude Project New and Modified Sources

Emission Unit Category	FIN	EPN	Description	PSD Emission Unit Type
Process Heaters	SATGASHTR	SATGASHTR	Sat Gas No. 3 Hot Oil Heater	New
	39BA3901	JJ-4	CCR Hot Oil Heater	Modified
Cooling Tower	44EF2	F-S-202	Mid-Plant Cooling Tower No. 2	New[3]
Equipment Piping Fugitive Emissions	F-SATGAS3	F-SATGAS3	Sat Gas No. 3 Fugitives	New[4]
	14-UDEX	F-14-UDEX	UDEX Fugitives	New[4]
			DHT Fugitives	New[4]

[3] Leaks from heat exchangers into cooling water.
[4] Fugitive emissions from new equipment piping components.

Equipment Piping Fugitive Emissions	37	F-37		
	39	F-39	NHT/CCR Fugitives	New[4]
	40	F-40	West Crude Fugitives	New[4]
	42	F-42	Mid Crude Fugitives	New[4]
	P-GB	F-GB	Gasoline Blender Fugitives	New[4]
	P-VOC	F-TK-VOC	VOC/Tank Loading Fugitives	New[4]
Planned Maintenance, Start-up, and Shutdown Activities	MSSFUGS-DC	MSSFUGS-Dc	Planned Maintenance, Start-up, and Shutdown Activities	New[5]

The majority of the new GHG emissions from the Project (99.8%) are from two process (hot oil) heaters, one new and one modified. These stationary combustion sources primarily emit carbon dioxide (CO_2) and trace amounts of nitrous oxide (N_2O) and methane (CH_4). The other 0.2% of the Project's GHG emissions are from the increase in fugitive emissions due to installation of a new cooling tower (leaks from the heat exchangers), leaks from new equipment piping components, and emissions from planned maintenance, start-up and shutdown activities at process vessels and tanks.

The evaluation of BACT was done on an individual basis for each new and modified emissions unit; however, similar units are grouped together in the text below because the steps for the evaluation are the same.

VIII. Domestic Crude BACT Analysis

A. Process Heaters (Sat Gas No. 3 and CCR Hot Oil Heaters): Post Combustion Controls

Background

The new 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. It will include a new hot oil heater, the Sat Gas No. 3 Hot Oil Heater, which will be equipped with SCR to reduce NO_x and a catalyst bed to control CO and VOCs, non-GHG pollutants.

[5] MSS emissions from increased maintenance activities for new process vessels and tanks.

The new Sat Gas Plant No. 3 consists of the new hot oil heater and new equipment piping. The heater fires mainly natural gas and a low flowrate stream from the Merox Treating Unit. GHG emissions from the combustion of the stream from the Merox Treating Unit are less than 0.5% of the total GHG emissions estimated from the Sat Gas No. 3 Hot Oil Heater for natural gas. Because the stream from the Merox Treating Unit is so small and the CO_2 emission factor is similar to that of natural gas, FHR estimated GHG emissions from the Sat Gas No. 3 Hot Oil Heater assuming the CO_2 emissions factor for facility-specific natural gas.

The CCR Unit is an existing process unit at the facility. Changes at the CCR Unit and the Naphtha Hydrotreater Unit will increase the firing duty of the CCR Hot Oil Heater from 90 MMBtu/hr to 123.6 MMBtu/hr (HHV). The CCR Hot Oil Heater can only fire CCR refinery fuel gas. FHR will add controls to the CCR Hot Oil Heater, which include SCR to reduce NO_x and a catalyst bed to control CO and VOCs, non-GHG pollutants.

Add-on, post combustion control technologies potentially exist for the streams exiting the two hot oil heaters, SATGASHTR and 39BA3901. These control technologies, for recovery of CO_2 from exhaust gas emitted from combustion units, are considered in this section for the two hot oil heaters, while the design and work practice control technologies are considered in the next section.

Step 1. Identify All Available Control Options

Carbon Capture and Sequestration (CCS)

CCS systems involve the use of adsorption or absorption processes to remove (capture) CO_2 from exhaust (flue) gas, with subsequent desorption to produce a concentrated CO_2 stream. Once CO_2 is captured from the exhaust gas, the captured CO_2 is compressed to 100 atmospheres or higher for ease of transport (usually by pipeline) to an appropriate location for sequestration. After the CO_2 is captured, compressed, and transported by pipeline, it is sequestered through underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). Numerous research and field studies, focused on developing a better understanding of the science and technologies for CO_2 storage, are ongoing.[6]

Step 2 – Elimination of Technically Infeasible Alternatives

EPA generally considers a technology to be technically feasible if it: (1) has been demonstrated and operated successfully on the same type of source under review, or (2) is available and applicable to the source type under review.

[6] U.S. Department of Energy (DOE), Office of Fossil Energy, National Energy Technology Laboratory, *Carbon Sequestration Program: Technology Program Plan*, February 2011.

A number of specific methods may potentially be used for separating (capturing) the CO_2 from the exhaust gas stream post combustion, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation.[7] Many of these methods are either still in development or are not suitable for treating process heater exhaust gas due to the characteristics of the exhaust stream.[7,8] Of the emerging CO_2 post combustion capture technologies, amine-based solvent absorption is the most commercially developed for state-of-the-art large scale CO_2 separation processes.

Post combustion CO_2 capture technology has been demonstrated in practice on steam methane reformers at a refinery,[9] but it has not been demonstrated in practice on hot oil heaters at petroleum refineries.[10] While CO_2 capture technologies may be commercially available, there is insufficient information at this time to conclude that CO_2 capture technology can be applied to exhaust streams from hot oil heaters with dilute concentrations[11] and low volumes of CO_2 similar to FHR's heater exhaust streams.

As a result, EPA believes that CCS is technically infeasible as an add-on pollution control technology for the hot oil heaters at the FHR West Refinery and can be eliminated as BACT. Because FHR provided a cost analysis of CCS with its permit application, we have included their CCS cost analysis in Step 4 of the BACT analysis as additional support for eliminating CCS as BACT.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

If CCS were technically feasible for this source category or process, EPA estimates that CCS would reduce GHG emissions (CO_2) from the hot oil heaters by approximately 269,005 tons per year,[12] based on a 90% capture efficiency and the emissions estimates provided by FHR, and that CCS would be the most effective add-on, post combustion control method for the hot oil heaters. No ranking is necessary because we are only evaluating one add-on control technology, so the one option is retained for Step 4.

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[7] *CO_2 Capture by Solid Adsorbents and Their Applications: Current Status and New Trends*, Qiang Wang, et.al, Energy & Environmental Science, April 2011.

[8] International Panel on Climate Change (IPCC), *Carbon Dioxide Capture and Storage*, Cambridge University Press September 2005.

[9] A fact sheet on the project, with additional links to project information, can be found at https://sequestration.mit.edu/tools/projects/port_arthur.html.

[10] U.S. Environmental Protection Agency (EPA), Office of Air Quality Planning and Standards (OAQPS), *EPA-457/B-11-001: PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, Page 33. Previously called the GHG Permitting Guidance in this SOB.

[11] FHR estimates that the exhaust stream contains 6-10% CO_2.

[12] This reduction does not take into account the additional 178,700 tons CO_2 that would be emitted by the new boiler, required to meet CCS energy requirements, which would result in an additional 17,870 tons of CO_2 (the 10% that is not captured by CCS) being released.

Step 4 – Evaluation of Control Options, with Consideration of Economic, Energy, and Environmental Impacts

Economic Impacts of CCS for the Project

Even though EPA believes that CCS is technically infeasible for this facility, as detailed in Step 2, FHR provided additional information that supports the rejection of CCS as BACT in Step 4.

The options for CO_2 transport and sequestration in the vicinity of Corpus Christi are limited at this time. In order to connect to the nearest commercial pipeline, FHR would have to construct approximately 200 miles of pipeline to connect to Denbury Resources' Green Pipeline near Alvin, Texas. Denbury is developing the Hastings Oil Field near Alvin, Texas as a location for EOR using CO_2. FHR's cost estimate is based upon transporting the CO_2 to this pipeline, but it does not include selection of a site for sequestration. There are other potential sequestration sites in Texas that are commercially viable, such as the SACROC EOR unit in the Permian Basin; however, that location is about 450 miles from the proposed project site. The closest site that is currently being field-tested to demonstrate its capacity for large-scale geological storage of CO_2 is the Southeast Regional Carbon Sequestration Partnership's (SECARB) Cranfield test site located in Mississippi's Adams and Franklin Counties. Mississippi is over 400 miles away from the proposed project site. Therefore, transport to either the SACROC or the SECARB sites were not alternatives used in this evaluation, and transport to the closer Denbury Pipeline was used in the cost analysis.

FHR developed a cost estimate of approximately $360 million for construction of the CCS system for the Project, using the post-combustion capture technology of amine-based solvent absorption. FHR included the following equipment, expenditures, and assumptions in the cost estimate:

- 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 is only necessary to produce the energy for the amine regeneration in the CCS system
- An amine capture skid for the additional 150# Steam Boiler
- Pipeline right of way acquisition and construction to the nearest available commercial CO_2 pipeline, located about 200 miles from the FHR Corpus Christi West Refinery.

Table 3 shows the cost estimate prepared by FHR for using amine-based solvent absorption CCS technology.

Table 3. FHR Domestic Crude Project CCS Cost Estimate

Description of Equipment Necessary for CCS Project	Initial Capital Cost (+/-50%) ($)
Amine Capture Skid - Sat Gas #3	$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

EPA Region 6 reviewed FHR's CCS cost estimate and determined that it adequately approximates the cost of CCS controls for the Project. The estimate shows the cost of the Project with CCS (approximately $760 million, plus CCS cost of approximately $360 million) is high in relation to the overall cost of the Project without CCS (approximately $760 million).

Energy and Environmental Impacts of CCS for the Project

The low concentration of CO_2 in the hot oil heater exhaust streams would complicate the absorption and desorption of CO_2, making capture of CO_2 difficult. In addition, the temperature of the stream would need to be reduced prior to separation, compression, and transmission. To achieve the necessary CO_2 concentration and temperature for effective sequestration, the recovery and purification of CO_2 from the exhaust gas would require additional equipment, operating complexity, and increased energy consumption. The additional process equipment required to separate, cool, and compress the CO_2 would result in increased fuel usage in order to meet the steam and electric load requirements of this system.

The on-site increase in make-up water utilization to implement CCS, in an area prone to drought, would be approximately 400 gallons per minute. This represents about a 10% increase in the facility's demand for fresh water. The additional on-site energy requirements to implement CCS would be approximately 350 MMBtu/hr (HHV), likely from purchased natural gas. The off-site energy use of the project would be approximately 117,000 megawatts per year, from energy provided by a power generating facility, not including the electricity used by the pipeline booster stations involved in the CO_2 transport.

Table 4 shows the on-site and off-site increase in GHG and non-GHG (criteria pollutant) emissions, estimated by FHR, if the CCS controls were added.

Table 4.   Estimated Emissions from CCS for Domestic Crude Project

Estimated Emissions from CCS for Domestic Crude Project		
	On-site Emissions from New CCS Boiler (TPY)	Secondary Emissions from Power Generation (TPY)
NO_x	11.46	45
SO_2	2.06	140
PM	11.39	-
CO	11.10	-
VOC	8.24	-
CO_2	17,870[13]	75,000

Based on the technical infeasibility analysis in Step 2 and the high, facility-specific cost for capture, transport, and storage of CO_2, EPA has eliminated CCS as an add-on pollution control technology as part of its BACT determination for this project.

Step 5 – Selection of BACT

See Section B, Process Heaters: Numerical, Design, and Work Practice Controls.

B. Process Heaters (Sat Gas No. 3 and CCR Hot Oil Heaters): Numerical, Design, and Work Practice Controls

As part of the PSD review, FHR provided a five-step top-down BACT analysis in its GHG permit application for the new and modified heaters.   EPA reviewed FHR's BACT analysis for the new and modified heaters and incorporated it into this SOB, and also used its own analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1. Identify All Available Control Options

- *Energy Efficient Design* – Minimize GHG emissions by limiting the amount of fuel burned based on design with such features as energy efficient burners, draft/trim instrumentation and controls, waste heat recovery using an air preheater, insulation/insulating jacks, reduction of air leakage, and reduction of slagging and fouling of heat transfer surfaces.
- *Energy Efficient Operating Practices* – Minimize GHG emissions by limiting the amount of fuel burned based on operational practices and proper maintenance of equipment, such as initial heater tuning and testing, annual heater tune-up, and operation using optimal temperature, combustion air O_2, and fuel for the equipment.
- *Use of Low Carbon Fuels* – Minimize GHG emissions by using lower carbon content fuel.

[13] Assuming 90% capture with CCS.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are technically feasible for controlling GHG emissions from process heaters and are retained for Step 3.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

EPA sponsored a study to characterize energy efficiency measures in the petroleum industry, published as the ENERGY STAR guide (2008).[14] Based on this study, the following energy savings can be realized from the use of these technologies for process heaters:

- Heater design (up to 10%),
- Periodic tune-up (1-10%),
- Minimize Excess O_2 (combustion air controls) (≈3%),
- Minimize Stack Temperature (air preheat/heat recovery) (8-18%), and
- Use of Low Carbon Fuels (28%).

Of the three control technologies brought forward (energy efficient design, energy efficient operating practices, and use of low carbon fuels), all are effective and are not exclusive of each other, so EPA did not rank them.

Step 4 – Evaluation of Control Options, with consideration of Economic, Energy, and Environmental Impacts

Neither FHR nor EPA identified any adverse collateral energy, environmental, or economic impacts as a result of energy efficient design, energy efficient operating practices, and use of low carbon fuels, so EPA will include all control options as BACT.

Energy Efficient Design

Heaters can be designed with efficient burners, instrumentation and controls to automatically control the fuel/air ratio and monitor and control O_2 leaks, more efficient heat transfer through waste heat recovery, and state-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency. These design features lower potential GHG emissions by reducing the required heater duty (fuel firing rate), which can substantially reduce energy use.

[14] Environmental Energy Technologies Division, University of California, sponsored by USEPA, *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers*, June 2008.

Energy Efficient Operating Practices

Energy efficient combustion practices can be achieved through operating practices such as limiting excess O_2 and stack exhaust temperature and conducting consistent periodic heater maintenance, such as tune-ups and optimization.

Periodic tune-ups of the heaters include:

- Preventative maintenance check of the fuel gas flow meters annually,
- Preventative maintenance check of the O_2 control analyzers quarterly, and
- Physical inspection, clean the burner tips, and perform combustion tuning and optimization, in accordance with 40 CFR Part 63, Subpart DDDDD (40 CFR § 63.7540 (a)(10)(i) - (a)(10)(vi)).

Use of Low Carbon Fuel

Natural gas is the lowest carbon fuel that can be combusted in the Saturate Gas No. 3 Hot Oil Heater, as designed for this existing refinery. Typically, gaseous fuels like natural gas are lower in carbon than liquid or solid fuels like diesel or coal, and thus have lower GHG emissions. Natural gas is also a very clean burning fuel with respect to criteria pollutants and, therefore, has minimal environmental impact compared to other fuels. The existing CCR Hot Oil Heater combusts refinery fuel gas, which is very similar to natural gas, but contains less methane and more hydrogen and ethane than natural gas.

The FHR Corpus Christi West Refinery produces a refinery fuel gas as a result of its processes, which is similar in properties to the natural gas it purchases. See Table 6 below. The FHR Corpus Christi West Refinery is designed to combust a blend of its refinery fuel gases in process heaters or boilers, which is a better use of the gas than flaring it. The CCR Hot Oil Heater is specifically designed to combust CCR refinery fuel gas, while the Sat Gas No. 3 Hot Oil Heater will be designed to combust natural gas (and the small flowrate steam from the Merox Unit).

Step 5 – Selection of BACT

Table 5 shows the proposed BACT limits and requirements for the new (Sat Gas No. 3) and modified (CCR) hot oil heaters.

Table 5. FHR Corpus Christi West Refinery BACT Limits for Hot Oil Heaters

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e	BACT Requirements
				TPY		
SATGAS HTR	SATGAS HTR	Sat Gas No. 3 Hot Oil Heater	CO_2	236,004.1	236,242	• 119.7 pounds (lbs) CO_2/MMBtu of fuel on a 365-day rolling average[15]
			CH_4	4.3		
			N_2O	0.43		

[15] The 119.7 lb/MMBtu limit does not apply to the Merox off-gas stream.

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e	BACT Requirements
				TPY		
						• Excess O_2 $\leq$ 4% on a 365-day rolling average[16] • Exhaust Temperature $\leq$ 350 degrees F on a 365-day rolling average[16] • Energy Efficient Design • Energy Efficient Operating Procedures • Use of Low Carbon Fuels • See permit conditions III.A.
39BA3901	JJ-4	CCR Hot Oil Heater	CO_2	62,890.1	63,193	• 116.2 lbs CO_2/MMBtu of fuel on a 365-day rolling average • Excess O_2 $\leq$ 4% on a 365-day rolling average[16] • Exhaust Temperature $\leq$ 350 degrees F on a 365-day rolling average[16] • Energy Efficient Design; • Energy Efficient Operating Procedures • Use of Low Carbon Fuels • See permit conditions III.A.
			CH_4	3.58		
			N_2O	0.72		

[16] FHR requested inclusion of the BACT requirements relating to excess O_2 and exhaust temperature based upon considerations specific to the operation of the Corpus Christi West Refinery and agreements between FHR and third parties. By including these provisions, EPA is not making a determination that the specific limits submitted by FHR are BACT for similar facilities or that similar limits are appropriate in other GHG permitting actions.

BACT Limit

In a February 17, 2014, response to an EPA request for additional information, FHR provided the information in Table 6 below to show the facility-specific CO_2 emission factors for natural gas and the refinery fuel gas used in the emission rate calculations for the hot oil heaters. FHR used Tier III methodology (Equation C-5) from 40 C.F.R. Part 98, Subpart C to calculate the CO_2 emission factors using actual carbon content, molecular weight, and higher heating values for purchased natural gas and the CCR refinery fuel gas systems from 2011 to 2013. To account for variability in the carbon content, molecular weight, and higher heating values of each of the different fuel gases, FHR calculated the CO_2 factor for each fuel using an average pound (lb) CO_2/MMBtu factor for 2011 to 2013 and added two standard deviations to the average. CH_4 and N_2O emission factors in Table 6 are from Table C-2 in 40 C.F.R. Part 98, Subpart C.

Table 6. FHR Corpus Christi West Refinery Fuel Gas Emission Factors

Fuel Gas System	CO_2 Emission Factor (lb/MMBtu)	CH_4 Emission Factor (kilogram/MMBtu)	N_2O Emission Factor (kilogram/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}

EPA reviewed the fuel gas data reported under the 40 CFR Part 98 GHG reporting requirements (submitted by FHR in a February 21, 2014, response to EPA's request for additional information) and found that the fuel data is variable for the high heating value and the carbon content (and thus, the molecular weight) of the fuel in the past three years. In one of numerous examples to illustrate this point, in 2011, the CCR Refinery highest monthly fuel gas HHV and the CCR Refinery lowest monthly HHV varied by about 28%. Therefore, EPA accepts FHR's approach of calculating the CO_2 emission factor by adding two standard deviations to the average CO_2 emission factor.

EPA proposes that the BACT limit for the Sat Gas No. 3 Hot Oil Heater, which will use 99.95% natural gas as a fuel, be 119.7 lb CO_2/MMBtu, based on the facility-specific emission factor for natural gas. EPA proposes that the BACT limit for the CCR Hot Oil Heater, which will use CCR refinery fuel gas, will be 116.2 lb CO_2/MMBtu, based on the facility-specific emission factor for the CCR refinery fuel gas.

Table 7 shows the facilities with units and GHG BACT limits similar to FHR.

Table 7. BACT for GHG for Facilities with Hot Oil Heaters

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Iowa Fertilizer Company Wever, IA	110.12 MMBtu/hr Natural Gas Fired Start-Up Heater, Fertilizer Production	Energy Efficiency/ Good Design & Combustion Practices	117 lb CO_2/MMBtu; 0.0023 lb CH_4/MMBtu; 0.00063 lb N_20/MMBtu; 638 Ton CO_2e 12-month rolling average	2012	12-A-390-P
Energy Transfer Company (ETC), Jackson County Gas Plant Ganado, TX	Four Processing Plants ▪4 Hot Oil Heaters (48.5 MMBtu/hr each) ▪4 Trim Heaters (17.4 MMBtu/hr each) ▪4 Molecular Sieve Heaters (9.7 MMBtu/each) ▪4 Regenerator Heaters (3 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit for process heaters per plant (one of each heater per plant) of 1,102.5 lbs CO_2/MMSCF (million standard cubic feet) 365-day average, rolling daily for each plant	2012	PSD-TX-1264-GHG
Energy Transfer Partners, LP, Lone Star NGL Mont Belvieu, TX	2 Hot Oil Heaters (270 MMBtu/hr each) 2 Regenerant Heaters (46 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters - 2,759 lb CO_2/bbl of NGL processed. Regenerator Heaters - 470 lbs CO_2/bbl of NGL processed. 365-day average, rolling daily	2012	PSD-TX-93813-GHG
ONEOK Hydrocarbon LP, Mont Belvieu NGL Fractionation Plant Mont Belvieu, TX	NGL Fractionation 3 Hot Oil Heaters (154 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters - 14.25 lb CO_2/bbl of Y-grade NGL processed for all 3 heaters combined.	2013	PSD-TX-106921-GHG
Targa Midstream Services LLC, Mont Belvieu Plant Mont Belvieu, TX	2 Hot Oil Heaters (144.45 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	Each Heater will have 4.06 lbs CO_2/barrel (bbl) per day of natural gas liquids processed limit	2013	PSD-TX-101616-GHG

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Diamond Shamrock Refining Company, Valero McKee Refinery Sunray, TX	Vacuum Heater (686,104,738. Scf/yr firing rate limit, Hydrotreater Charge Heater (303,702,244 scf/yr firing rate limit)	Energy Efficiency/ Good Design & Combustion Practices	Each heater will have a 0.11 lb CO_2e/scf fuel on a 365-day rolling basis.	2013	PSD-TX-861-GHG

EPA proposes a BACT limit of 119.7 lb CO_2/MMBtu on a 365-day rolling average for the new Sat Gas No. 3 Hot Oil Heater and 116.2 lb CO_2/MMBtu for the modified CCR Hot Oil Heater, values calculated using facility-specific fuel data from 2011 to 2013. These proposed BACT limits for the FHR Corpus Christi West Refinery heaters are comparable to the Iowa Fertilizer Company BACT permit limit of 117 lb CO_2/MMBtu and the Diamond Shamrock Valero McKee Refinery permit limit of 114.2 lb CO_2/MMBtu (0.11 lb CO_2/standard cubic foot (scf) divided by the heat input factor). Because of the high variability of the FHR Corpus Christi West Refinery fuels, as discussed earlier and shown in the permitting record, EPA believes that these higher limits are justified. EPA proposed annual emissions limits only for CH_4 and N_2O for the Project because these GHG gas emissions only contribute 0.1% of the CO_2e emissions from the heaters.

Table 8 shows EPA's proposal for BACT design and operating practices for the hot oil heaters.

Table 8. FHR Corpus Christi West Refinery BACT Design and Operating Practices for Hot Oil Heaters

Technology	Description
Energy Efficient Design	Minimize GHG emissions by limiting amount of fuel burned based on design measures, such as: • Energy Efficient Burners • Draft/Trim Instrumentation and Controls • Waste Heat Recovery—use of an Economizer and Air Preheater • Insulation/Insulating Jackets • Reduce air leakage through use of stack O_2 instrumentation to help identify air leaks, and use a preventative maintenance program • Reduce slagging and fouling of heat transfer surfaces through use of refinery fuel gas and natural gas

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 • Limit the excess O_2 to 4%[17] • Limit the Stack Exit Temperature to 350 Degrees Fahrenheit (F)[17]
Low Carbon Fuels	Natural gas and refinery fuel gas are lower carbon fuels than other fuels that could be used and will be the only fuels fired in the heaters (except for the low volume stream from the Merox Unit.)

<u>BACT Limits and Compliance:</u>

FHR will maintain records of heater tune-ups, burner tip maintenance, O_2 analyzer calibrations and maintenance for all the heaters. In addition, FHR will maintain records of fuel usage and stack exhaust temperature.

FHR will demonstrate compliance with the CO_2 limit for the heaters using metered fuel consumption and facility-specific factors for natural gas and CCR refinery fuel gas based on fuel composition. FHR will determine, on a weekly basis, the fuel gross calorific value (GCV), high heat value (HHV), carbon content (CC), and molecular weight by the procedures contained in 40 CFR § 98.34(b)(3). FHR will use these numbers to calculate the CO_2 mass emissions on a daily basis. FHR will calculate, on a daily basis, the fuel gas firing rate in MMBtu based on the heating value of the fuel gas (HHV) and the volume of gaseous fuel combusted. Then FHR will divide the CO_2 mass emission by the fuel gas firing rate in MMBtu and add it to the 365-day rolling average to compare to the BACT numerical emission limit. The 119.7 lb CO_2/MMBtu limit does not apply to the Merox off-gas stream.

The equation for estimating monthly CO_2, CH_4, and N_2O emissions for the Merox off-gas stream is based on equation Y-19 in 40 CFR § 98.253(j) (substituting monthly values for the annual values) and is as follows:

$$E_x = \sum_{p=1}^{N}\left((VR)_p \times (MF_x)_p \times \frac{MW_x}{MVC} \times (VT)_p \times 0.001\right) \qquad \text{(Eq. Y-19)}$$

Where:

E_X = Annual emissions of each GHG from process vent (metric ton/year)

N = Number of venting events per year

P = Index of venting events

[17] See footnote 16.

$(VR)_p$ = Average volumetric flow rate of process gas during the event (scf per hour) from measurement data, process knowledge, or engineering estimates

$(MF_X)_p$ = Mole fraction of GHG x in process vent during the event (kg-mol of GHG x/kg-mol vent gas) from measurement data, process knowledge, or engineering estimates

MW_X = Molecular weight of GHG x (kg/kg-mole); use 44 for CO_2 or N_2O and 16 for CH_4

MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia)

$(VT)_p$ = Venting time for the event, (hours)

0.001 = Conversion factor (metric ton/kg)

FHR will add the results of these calculations to the results for the Sat Gas No. 3 Hot Oil Heater (below) to demonstrate compliance with the CO_2e BACT emission limit on a 12-month rolling total basis.

The equation for estimating CO_2 emissions from natural gas and CCR refinery fuel gas is based on equation C-5 in 40 CFR § 98.33(a)(3)(iii) (substituting daily values for the annual values) and is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas or refinery fuel gas (short 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 40 CFR § 98.3(i).
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 at 40 CFR § 98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at 40 CFR § 98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in 40 CFR § 98.6
44/12 = Ratio of molecular weights, CO_2 to carbon
0.001 = Conversion of kg to metric tons
1.102311 = Conversion of metric tons to short tons

As an alternative, FHR may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions. If this alternative is selected, the calculations shall be in accordance with the methodology provided in 40 CFR § 98.33(a)(4).

For natural gas and CCR refinery fuel gas, FHR will also use equation C-5 in 40 CFR § 98.33(a)(3)(iii) to calculate the annual CO_2 emissions, and equation C-8b in 40 CFR § 98.33(c)(1)(ii) to calculate the annual CH_4 and N_2O emissions to compare with the annual CO_2e emission limit. FHR will keep records of the calculations to demonstrate compliance with the CO_2e BACT emission limit on a 12-month rolling total basis.

Equation C-8b in 40 CFR § 98.33(c)(1)(ii) is as follows:

$$CH_4 \text{ or } N_2O = 1 \times 10^{-3} * \text{Fuel} * \text{EF}$$

where:
CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of natural gas or CCR refinery fuel gas (metric tons).
Fuel = Annual natural gas or CCR refinery fuel gas usage (MMBtu).
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C-2 of 40 CFR Part 98, Subpart C (kg CH_4 or N_2O per MMBtu).
1×10^{-3} = Conversion factor from kilograms to metric tons.

FHR will limit excess O_2 in each heater's 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).[18] FHR will determine the 365-day rolling average excess O_2 level in each heater's exhaust 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).

FHR will limit the stack exhaust temperature to 350 degrees F on a 365-day average basis for each heater, excluding periods of heater start-up, shutdown, and low firing rates (<60% of maximum design capacity).[19] FHR will determine the 365-day rolling average stack exit temperature in each heater's exhaust 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).

FHR will determine, on a daily basis, the average stack exhaust temperature for each heater and add the result to the 365-day rolling average. Stack exit temperatures recorded during periods of monitoring instrumentation malfunction and maintenance shall be excluded from use in the 365-day rolling average, provided that monitoring downtime does not exceed 5% of any 365-day rolling period.

[18] See footnote 16.
[19] See footnote 16.

FHR will determine, on a daily basis, the 24-hour average stack exit temperature for each heater 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).

FHR will perform corrective action on a hot oil heater if the average stack exhaust temperature is above 350 degrees F for the 24-hour period, excluding periods of start-up, shutdown, and low firing rates (<60% of maximum design capacity).[20] This occurrence shall be considered an excursion. FHR will minimize the duration of an excursion, and restore normal operation of the hot oil heater as expeditiously as practicable, in accordance with good air pollution control practices and safety practices.

FHR will report temperature monitor downtime in excess of 5% of any 365-day period and excursions, and include a discussion of the corrective actions taken for each excursion in the quarterly excess emissions report.

The proposed permit requires an initial performance test for CO_2 for the two hot oil heaters. FHR will complete a performance test every five years, plus or minus six months, after the previous performance test was performed, or within 180 days after the issuance of a permit renewal, whichever comes later, to verify continued performance at the permitted emission limits. The proposed permit does not require an initial stack test demonstration for CH_4 and N_2O emissions because the CH_4 and N_2O emission are estimated to be less than 0.1% of the total CO_2e emissions from the heaters and are considered a *de minimis* contribution to the total CO_2e emissions compared to the CO_2 emissions.

IX. Cooling Towers

For the proposed project, FHR will construct a new cooling tower known as Mid-Plant Cooling Tower No. 2 (44EF2). Methane leaks from heat exchangers into cooling water may cause GHG emissions from the cooling tower. Methane in the cooling water at the FHR Corpus Christi West Refinery is ultimately air-stripped and emitted from the cooling towers. FHR estimated the methane emissions from the cooling tower based on the VOC emission rate and a maximum weight percent of methane in the VOCs of 10%. The methane emissions from the cooling tower are about 0.003% of the Project's total CO_2e emissions.

FHR, formerly Koch Petroleum Group, LP, is subject to a federally issued Consent Decree (CD), Civil Action Case Number 00-cv-2756, December 22, 2000, as amended by the First Amendment in 2006 and the Second Amendment in 2008 (See <http://www2.epa.gov/enforcement/koch-petroleum-group-lp-refinery-settlement>). The CD, as amended, contains provisions for regulation of the FHR Corpus Christi West Refinery cooling towers.

As part of the PSD review, FHR provided a five-step top-down BACT analysis in its GHG permit application for the new cooling tower. EPA reviewed FHR's BACT analysis for the new

[20] See footnote 16.

cooling tower and conducted its own analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1 – Identification of Potential Control Technologies for GHGs

FHR identified only one available technology: cooling water monitoring and repair of leaking heat exchangers. EPA is unable to independently identify any other available technology. Therefore, a detailed analysis under Steps 2 through 4 is not necessary.

- *Cooling Tower Monitoring and Repair* – This technology consists of monthly monitoring of the cooling water to detect leaks and repair of exchangers that are leaking. Requirements for controlling VOC emissions at the cooling towers are included as part of FHR's TCEQ Permit No. 6819A and the Consent Decree, as amended.

Step 2 – Elimination of Technically Infeasible Alternatives

The option identified in Step 1 is technically feasible for controlling GHG emissions from the cooling towers and is retained for Step 3.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The one option is retained for Step 4.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Neither FHR nor EPA identified any adverse collateral energy, environmental, or economic impacts as a result of the cooling tower monitoring and repair measures that are proposed as BACT.

Step 5 – Selection of BACT

Because the leak monitoring technology measures total VOCs and does not speciate the methane, EPA did not select a numerical BACT emission standard for Cooling Tower No. 2. Instead, BACT is a work practice standard. FHR will implement a monthly cooling tower leak monitoring and repair program that utilizes the monitoring and repair requirements, including timelines, monitoring schedule, training requirements, and repair schedules, in the CD, as amended. In addition, FHR will maintain records of monitoring and corrective action in accordance with TCEQ permit No. 6819.

The cooling tower requirements from the TCEQ Permit and CD are excerpted in Appendix 1.

X. Equipment Piping Fugitive Emissions

Fugitive GHG emissions from equipment piping are the result of leaks from new piping components such as valves, flanges, connectors, pumps, compressors, and agitators that will be added as a part of the Project. Fugitive GHG emissions from equipment piping are mainly generated from lines transporting fuel gas and natural gas, that contain methane. FHR calculated the methane emissions based on the VOC emission rates and the estimated weight percent of methane. The methane emissions from equipment piping fugitive emissions account for about 0.06% of the Project's total CO_2e emissions.

The CD, as amended, contains provisions for regulation of the FHR Corpus Christi West Refinery Leak Detection and Repair (LDAR) program.

As part of the PSD review, FHR provided a five step top-down BACT analysis in its GHG permit application for the equipment piping fugitive emissions. EPA reviewed FHR's BACT analysis for the equipment piping fugitive emissions and conducted its own analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1 – Identification of Potential Control Technologies for GHGs

LDAR programs are used at refineries to detect and control VOC emissions. Methane is a component of the VOC emissions. The following are potential control technologies:

- *LDAR* – LDAR includes requirements for EPA Method 21 (Determination of Volatile Organic Compound Leaks) monitoring of equipment components (e.g., valves, flanges, connectors, pumps, compressors, and agitators) for detection of leaks; a leak definition that dictates when to repair and report on components that are leaking; and timeframes and methods for repair. LDAR regulations for refineries include 40 C.F.R. Part 60, Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries.
- *Enhanced LDAR* – LDAR program enhancements may include a lower definition of a leak than the one required by regulations, a component threshold concentration, an increase in the leak monitoring frequency above what is required by the regulations, and the installation of components with "low leak" technologies.
- *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.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 2 are technically feasible for controlling GHG from equipment piping fugitive emissions and are retained for Step 3.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

For the LDAR programs listed, the most effective program is the one with the most enhanced LDAR features:

1. Enhanced LDAR – leak definition lower than 500 parts per million by volume (ppmv), leak monitoring frequency higher than once per quarter, and installation of "low leak" valves

2. LDAR – the most common leak definition is 500 ppmv and monitoring is done once per quarter
3. Optical Gas Imaging LDAR – camera leak detection level is typically not lower than 500 ppmv and is often significantly greater based on the limitations of the camera

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

EPA determined that the BACT proposed by FHR (LDAR enhancements required by FHR's TCEQ Permits and the CD, as amended) comprise the most effective control technology for the equipment piping fugitive emissions at the FHR Corpus Christi West Refinery.

Neither FHR nor EPA identified any adverse collateral energy, environmental, or economic impacts as a result of the enhanced LDAR measures proposed as BACT.

Step 5 – Selection of BACT

Because the leak monitoring equipment measures total VOCs and does not speciate the methane, EPA did not select a numerical BACT emission standard for the equipment piping fugitive emissions at FHR's Corpus Christi West Refinery. BACT for the GHG fugitive emissions associated with the equipment piping fugitive emissions from the Project is enhanced LDAR, following the enhanced provisions of 28 VHP Fugitive Monitoring Requirements listed in FHR's TCEQ permit and the CD, as amended. Table 9 shows select enhanced LDAR provisions for the FHR Corpus Christi West Refinery and the source of the requirement.

Table 9. Select Enhanced LDAR at the FHR Corpus Christi West Refinery

Enhanced Provision	**Source**
Installation of Low Leaking Technology for Valves (< 100 ppm leakage as purchased)	CD (Equipment Plan to Minimize Leaks)
As observed Audio, Visual, Olfactory (AVO) program	28VHP/TCEQ Permit
Annual Flange/Connector Monitoring	TCEQ Permit
Internal Leak Definition: 500 ppmv for valves, 2000 ppmv for pumps	CD/TCEQ Permit
First Attempt at Repair at 50 ppmv, excluding control valves and other components LDAR personnel are not authorized to repair	CD

The TCEQ 28 VHP Fugitive Monitoring Requirements and EPA CD LDAR requirements are excerpted in Appendix 2.

XI. Maintenance, Start Up and Shutdown Fugitive Emissions for New Units

Fugitive GHG emissions from MSS activities at the FHR Corpus Christi West Refinery may result from planned maintenance of new process vessels for the Sat Gas No. 3 Unit and additional storage tanks required for the Project. These vessels and tanks are not sources of GHG emissions during normal operations but can emit GHGs during maintenance activities.

Although the emissions that can be controlled are routed to a control device[21] (flare, flare gas recovery system, thermal oxidizer, engine, or carbon canister), some fugitive emissions and emissions from the control devices themselves remain. The fugitive emissions are from:

- Opening (degassing) of process vessels and associated piping (opening the equipment to atmosphere releasing any residual VOC/methane to the atmosphere after the initial cleaning and decommissioning, and routing of the emissions to the flare gas recovery unit).
- Loading of vacuum trucks (transferring materials from one container to another and emptying tanks and other vessels during maintenance activities). If required to be controlled, some emissions can be routed to a carbon canister, while emissions sent to an engine or thermal oxidizer generate some GHG emissions from combusting vapors routed to the control device.
- Tank maintenance including refilling the tanks after a product change, tank degassing, and refilling tanks after a tank degassing/cleaning. Emissions sent to an engine or thermal oxidizer for destruction generate some GHG emissions from combusting vapors routed to the control device.

The MSS fugitive emissions account for 0.002% of the emissions from the Project. The MSS fugitive emissions consist mainly of CO_2 emissions, with emissions from CH_4 and N_2O only contributing 0.06% of the total CO_2e emissions from these activities. Therefore, the analysis focuses on mitigating CO_2 emissions, which will result in a corresponding reduction in other GHGs.

As part of the PSD review, FHR provided a five step top-down BACT analysis in its GHG permit application for the MSS fugitive emissions. EPA reviewed FHR's BACT analysis for the MSS fugitive emissions and conducted its own analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Minimize maintenance emissions through good operational practices* - Minimize fugitive maintenance emissions by first pumping liquids to recovery, depressuring and purging to a flare gas recovery unit, or another control device, and opening equipment to atmosphere only when the methane or VOC concentration is below 10,000 ppmv where practical, unless doing so would create an unsafe condition. Route non-fugitive emissions from the vacuum trucks and tank maintenance to the control device and maintain good combustion practices as required by TCEQ permit.

FHR identified only one available technology for the MSS fugitive emissions: Minimize maintenance emissions through good operational practices. EPA is unable to independently identify any other available technology and notes that all non fugitive emissions (that is,

[21] Required by the TCEQ permit.

emissions that are able to be captured) are currently routed to a control device. Therefore, a detailed analysis under Steps 2-4 is not necessary.

Step 2 – Elimination of Technically Infeasible Alternatives

The option identified in Step 2 is technically feasible for controlling MSS fugitive emissions and is retained for Step 3.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The one option is retained for Step 4.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Neither FHR nor EPA identified any adverse collateral energy, environmental, or economic impacts as a result of the MSS fugitive emission measures proposed as BACT. Because of the technical and economic difficulties in measuring the fugitive emissions, the BACT limit will be expressed as a work practice standard.

Step 5 – Selection of BACT

BACT for the MSS fugitive emissions is minimizing maintenance emissions through good operational practices. This includes minimizing fugitive maintenance emissions by first pumping liquids to recovery, depressuring and purging to a flare gas recovery unit, or another control device, and opening equipment to atmosphere only when the methane or VOC concentration is below 10,000 ppmv where practical, unless doing so would create an unsafe condition, and routing non-fugitive emissions from the vacuum trucks and tank maintenance to the control device in accordance with TCEQ Permit No. 6819A.

XII. Threatened and Endangered Species Act

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA 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.

To meet the requirements of Section 7 of the ESA, EPA has reviewed and adopted a final draft Biological Assessment (BA) dated February 13, 2014, prepared by Barr Engineering Company ("Barr") on behalf of FHR and EPA. The BA identifies the following sixteen federally listed threatened or endangered species that may be present in Nueces County, Texas:

Federally Listed Species for Nueces County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS), and the Texas Parks and Wildlife Department (TPWD)

Species	Scientific Name
Reptiles	
Green sea turtle	*Chelonia mydas*
Hawksbill sea turtle	*Eretmochelys imbriacata*
Kemp's ridley sea turtle	*Lepidochelys kempii*
Leatherback sea turtle	*Dermochelys coriaea*
Loggerhead sea turtle	*Caretta caretta*
Birds	
Piping plover	*Charadrius melodus*
Northern aplomado falcon	*Falco femoralis septentrionalis*
Whooping crane	*Grus americanus*
Eskimo curlew	*Numenius borealis*
Fish	
Smalltooth sawfish	*Pristis pectinata*
Mammals	
Gulf coast jaguarundi	*Herpailuraus yagouaroundi cacomitli*
Ocelot	*Leopardus pardalis*
West Indian manatee	*Trichechus manatus*
Red wolf	*Canis rufus*
Plants	
Slender rush-pea	*Hoggmannseggia tenella*
South Texas ambrosia	*Ambrosia cheiranthifolia*

EPA has determined that issuance of the proposed permit for the Domestic Crude Project at the existing FHR Corpus Christi West Refinery will have no effect on nine of the listed species, specifically the piping plover (*Charadrius melodus*), Northern aplomado falcon (*Falco femoralis septentrionalis*), smalltooth sawfish (*Pristis pectinata*), Gulf coast jaguarundi (*Herpailuraus yagouaroundi cacomitli*), ocelot (*Leopardus pardalis*), red wolf (*Canis rufus*), slender rush-pea (*Hoffmannseggia tenella*), eskimo curlew (*Numenius borealis*), and South Texas ambrosia (*Ambrosia cheiranthifolia*). These species are either thought to be extirpated from Nueces County or Texas, or are not present in the Action Area.[22]

Two species, the whooping crane (*Grus americana*) and the West Indian manatee (*Trichechus manatus*), have the potential to occur within in the Action Area. Based on the information provided in the BA, EPA has determined that the issuance of the permit may affect, but is not likely to adversely affect these two species. By letter dated March 19, 2014, EPA requested

[22] The Action Area is defined on Page viii of the FHR BA.

concurrence with these determinations from the USFWS Corpus Christi, Texas Ecological Services Field Office.

Additionally, five federally-listed marine species may be present within the Action Area: the leatherback sea turtle (*Dermochelys coriacea*), the green sea turtle (*Chelonia mydas*), the Kemp's ridley sea turtle (*Lepidochelys kempii*), the loggerhead sea turtle (*Caretta caretta*), and the Hawksbill sea turtle (*Eretmochelys imbricate*). As a result of the potential occurrence and based on the information provided in the BA, EPA has determined that the issuance of the permit may affect, but is not likely to adversely affect these species. By letter dated February 21, 2014, EPA requested concurrence with these determinations from the NMFS Protected Resources Division.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. A copy of the February 13, 2014 final draft BA is posted on EPA's Region 6 Air Permits Website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XIII. Magnuson-Stevens Fishery Conservation and Management Act

The 1996 Essential Fish Habitat (EFH) amendments to the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) set forth a mandate for the National Oceanic Atmospheric Administration's National Marine Fisheries Service (NMFS), regional fishery management councils, and other federal agencies to identify and protect important marine and anadromous fish habitat.

To meet the requirements of the Magnuson-Stevens Act, EPA reviewed and adopted the February 26, 2014 EFH Assessment prepared by Barr on behalf of FHR and EPA.

The FHR Corpus Christi West Refinery is adjacent to tidally influenced portions of the Viola Ship Channel that adjoin Corpus Christi Bay, which leads to the Gulf of Mexico. These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, subadult or adult stages of red drum (*Sciaenops ocellatus*), shrimp (four species), reef fish (forty-three species), and neonate and juvenile of the scalloped hammerhead shark (*Sphyrna lewini*), bull shark (*Carcharhinus leucas*), sharpnose shark (*Rhizoprionodon terraenovae*), and spinner shark (*Carcharhinus brevipinna*).

Based on the information provided in the EFH Assessment, EPA has determined that issuance of the proposed permit for the Domestic Crude Project will have no adverse impacts on Essential Fish Habitat. Air modeling indicates that pollutant levels will be below *de minimis* levels over the water, and all wastewater and stormwater discharges that will be generated as a result of the project will be pretreated onsite, resulting in negligible impacts on the water quality of the Viola Ship Channel.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect Essential Fish Habitat. A copy of the February 26, 2014, EFH Assessment is posted on EPA's Region 6 Air Permits Website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XIV. National Historic Preservation Act (NHPA)

Section 106 of the National Historic Preservation Act (NHPA) requires EPA to consider the effects of this undertaking (issuance of the permit) on properties eligible for inclusion on the National Register of Historic Places. To make this determination, EPA relied upon and adopted the February 17, 2014, Cultural Resource Report prepared by Barr on behalf of FHR and EPA.

For purposes of the Section 106 review, the Area of Potential Effect (APE) was identified as the construction footprint of the proposed Domestic Crude Project and new parking area within FHR's existing West Refinery facility covering a total of 167 acres. Barr conducted a field survey within the APE and a desktop review within a 1.9-mile radius of the APE. The desktop review included an archaeological background and historical records review using the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). Based on the desktop review, several cultural surveys were conducted previously within and throughout the APE. Twenty-three archaeological sites were identified from those surveys within a 1.9-mile radius of the APE. Five of the twenty-three recorded archeological sites were identified to be within the APE and three of those sites were determined to be eligible or potentially eligible for listing on the National Register (NR). FHR will avoid the three NR-potentially eligible/eligible sites during construction of the project. Based on the field survey, including shovel testing of the parking area, no archeological resources were identified. No shovel testing was conducted for the construction footprint, as shovel testing had been performed already in previous cultural surveys.

EPA Region 6 determines that, while there are cultural materials of historic or prehistoric age identified within the 1.9-mile radius of the APE, the potential for intact archaeological resources is low within the construction footprint of the project itself. There are no historic properties located within the APE, and while there are archaeological resources within the APE, they will be avoided. EPA has therefore determined that issuance of the permit to FHR will not affect properties on or potentially eligible for listing on the NR.

On February 20, 2014, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the February 17, 2014, Cultural Resource Report is posted on EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XV. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., In re Prairie State Generating Company, 13 E.A.D. 1, 123 (EAB 2006); In re Knauf Fiber Glass, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the BACT for those emissions. The GHG BACT analysis does not select environmental controls for non-GHG (criteria) pollutants, because unlike the criteria pollutants for which EPA has historically issued PSD permits, there are no NAAQS for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are 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 [PSD and Title V Permitting Guidance for GHGS at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XVI. Conclusion and Proposed Action

Based on the information supplied by FHR, our review of the analyses contained in the TCEQ Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the FHR Corpus Christi West Refinery would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue FHR a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. (See Table 11 for the Annual Emissions limits.) This permit is subject to review and comment. EPA will make a final decision on issuance of the permit after considering comments received during the public comment period.

Table 10. FHR Corpus Christi West Refinery GHG Annual Emission Limits

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2,3]	BACT Requirements
				TPY[2]		
SATGAS HTR	SATGAS HTR	Sat Gas No. 3 Hot Oil Heater	CO_2	236,004	236,242	• 119.7 lbs CO_2/MMBtu of fuel on a 365-day rolling average[4] • Excess Oxygen (O_2) ≤ 4% on a 365-day rolling average • Exhaust Temperature ≤ 350 degrees F on a 365-day rolling average • Energy Efficient Design • Energy Efficient Operating Procedures • Use of Low Carbon Fuels • See permit conditions III.A.1.
			CH_4	4.35		
			N_2O	0.43		
39BA3901	JJ-4	CCR Hot Oil Heater	CO_2	62,890	63,193	• 116.2 lbs CO_2/MMBtu of fuel on a 365-day rolling average • Excess O_2 ≤ 4% on a 365-day rolling average • Exhaust Temperature ≤ 350 degrees F on a 365-day rolling average • Energy Efficient Design • Energy Efficient Operating Procedures • Use of Low Carbon Fuels • See permit condition III.A.1.
			CH_4	3.58		
			N_2O	0.72		
44EF2	F-S-202	Mid-Plant Cooling Tower No. 2	CH_4	No Numerical Emission Limit[5]	No Numerical Emission Limit[5]	• Leak detection and monthly monitoring of cooling water, and heat exchanger repair in accordance with Consent Decree (CD)[6] and the TCEQ Permit. • See permit condition III.A.2.

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2,3]	BACT Requirements
				TPY[2]		
F-SATGAS3 14-UDEX 37 39 40 42 P-VOC P-GB	F-SATGAS3 F-14-UDEX F-37 F-39 F-40 F-42 F-TK-VOC F-GB	Equipment Piping Fugitive Emissions	CH_4	No Numerical Emission Limit[7]	No Numerical Emission Limit[7]	• Enhanced LDAR in accordance with the CD and 28 VHP Fugitive Monitoring Requirements. Annual flange/connector monitoring in accordance with TCEQ Permit. See permit condition III.A.3.
MSSFUGS-DC	MSSFUGS-DC	MSS Fugitive Emissions	CO_2	No Numerical Emission Limit[8]	No Numerical Emission Limit[8]	• Good operational practices in accordance with the TCEQ Permit. See permit condition III.A.4.
			CH_4	No Numerical Emission Limit[8]		
			N_2O	No Numerical Emission Limit[8]		
				299,122[10]	**299,884 CO_2e**[9, 10]	
			CH_4	**16.76**[10]		
			N_2O	**1.15**[10]		

1. Compliance with the annual emission limits in tpy is based on a 12-month rolling total.
2. The tpy emission limits specified in this table, which include emissions from the facility during all operations including MSS activities, shall not be exceeded for this facility.
3. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298. The GWP are multipliers used to convert pounds CH_4 and N_2O to pounds CO_2e.
4. The 119.7 lb CO2/MMBtu limit does not apply to the Merox off-gas stream.
5. Estimated cooling tower GHG emissions are entirely from methane and total .55 tpy methane, which equates to 13.75 tpy CO_2e. GHG emissions from the cooling tower are from the stripping of VOCs (including methane) from the cooling water. In lieu of an emission limit, the emissions will be limited by implementation of work practice standards as BACT.
6. The Consent Decree (CD) refers to the federally issued Consent Decree, Civil Action Case Number 00-cv-2756, December 22, 2000, as amended by the First Amendment in 2006 and the Second Amendment in 2008.
7. Estimated new equipment piping component fugitive emissions are entirely from methane and total 8.22 tpy methane, which equates to 205.5 tpy CO_2e. (In tpy CO_2e: F-SATGAS3,161; F-14-UDEX, 0.25; F-37, 3.75; F-39, 1.5; F-40, 8; F-42, 22.75; F-TK-VOC, 7.25; and F-GB 1.) In lieu of an emission limit, the emissions will be limited by implementation of work practice standards as BACT.
8. Estimated MSS fugitive emissions are 228 tpy CO_2, 0.06 tpy CH_4, and 0.0018 N_2O for a total of 230 tpy CO_2e. MSS fugitive emissions are from vacuum truck loading, tank degassing, and tank refilling. In lieu of an emission limit, the emissions will be limited by implementation of work practice standards as BACT.
9. The total estimated emissions are for the units that are new or modified by this project, including the baseline emissions of the CCR Hot Oil Heater of 20,484 CO_2e. Emissions from downstream units that will have emission increases due to increased utilization and debottlenecking are not included in this table or this permit.
10. Total emissions are listed for informational purposes only and do not constitute emission limits.

APPENDICES

Appendix 1 – TCEQ Permit and EPA CD Cooling Tower Requirements

This appendix contains excerpts from FHR's TCEQ Permit and the EPA CD regarding the requirements for the cooling towers. It is not meant to be a listing of all requirements that apply to these units.

TCEQ Permit

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)**

EPA 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.

Appendix 2 – TCEQ 28 VHP Fugitive Monitoring Requirements (Permit) and EPA CD LDAR Requirements

This appendix contains excerpts from FHR's TCEQ Permit and the EPA CD regarding the requirements for Leak Detection and Repair (LDAR). It is not meant to be a listing of all requirements that apply to LDAR at the facility.

TCEQ Permit

<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 by monitoring 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)

EPA Consent Decree

VI. PROGRAM ENHANCEMENTS RE: LEAK DETECTION AND REPAIR
Program Summary: Koch agrees to undertake the following measures regarding leak detection and repair ("LDAR") at its refineries in accordance with the following schedule. Unless otherwise stated, the Corpus Christi East and West refineries will be considered as one LDAR program for purposes of this Agreement. Unless otherwise stated, all actions will commence on January 1, 2001.
75. By no later than December 31, 2001, Koch shall develop a written refinery-wide program for LDAR compliance

for each refinery. These programs shall include, at a minimum: an overall refinery-wide leak rate goal (to be applied unit-by-unit), procedures for identifying leaking components, and procedures for identifying and including new components in the LDAR program. As set forth below, certain elements of the program will be enforceable by EPA, and Koch will implement other management-type elements on an enforceable schedule, but the elements themselves will not be enforceable against Koch under the terms of this Consent Decree. Koch will implement this program according to the schedules specified in the Paragraphs below.

76. By no later than December 31, 2002, Koch's LDAR programs shall be implemented refinery-wide, including all components within all areas that are owned and maintained by the refineries. As referenced in this Section, "components" shall mean applicable regulated equipment as defined in 40 C.F.R. Part 60, subpart VV, and 40 C.F.R. Part 63, subparts H and CC, excluding the definition of "process unit."

77. By no later than December 31, 2001, Koch shall develop and begin implementing the following training programs at each refinery:

(a.) For new LDAR personnel, Koch shall provide and require LDAR training prior to the employee beginning work in the LDAR group;

(b.) For all LDAR personnel, Koch shall provide and require completion of annual LDAR training; and

(c.) For all other refinery operations personnel, Koch shall provide and require annual review courses for LDAR monitoring.

78. Koch shall implement the following audit programs (the Corpus Christi refineries will be audited as one LDAR program) focusing on comparative monitoring, records review and observation of the LDAR technicians' actual calibration and monitoring techniques:

(a.) Koch shall conduct biennial internal audits of each refinery's LDAR program. These audits will be conducted by sending representative LDAR personnel from one Koch refinery to the other. One refinery will have its first audit during the first full calendar year after the Consent Decree is lodged. The other refinery will conduct its first audit no later than the following calendar year; and

(b.) Koch agrees to have a third party audit each refinery's LDAR program at least twice during the overall life of the Consent Decree.

79. By December 31, 2002, Koch shall implement an internal leak definition of 500 ppmv for all valves, and 2000 ppmv for all pumps. Koch may continue to report leak rates against the regulatory leak definition, or may elect to use the lower leak rate definition for reporting purposes.

80. Beginning January 1, 2001, Koch shall require LDAR personnel to make a "first attempt" at repairing any valve that has a reading above 50 ppmv, excluding control valves and other components that LDAR personnel are not authorized to repair. Koch will only record, track and remonitor leaks above Koch's internal leak definition.

81. Koch shall implement a program of more frequent monitoring by December 31, 2002, for all valves by choosing one of the following options on a process unit by process unit basis:

(a.) Quarterly monitoring with no ability to skip periods. This option cannot be chosen for process units subject to the HON or the modified-HON option in the Refinery MACT;

(b.) Implementation of a Sustainable Skip Period Program as set forth in Attachment 1 to this Consent Decree;

(c.) Units that have already utilized a skip leak interval with a leak definition as listed in Paragraph 79, are not required to return to a more frequent monitoring interval upon application of the Sustainable Skip Period Program as of December 31, 2002, but shall immediately be subject to the requirements of the program on a going forward basis; and

(d.) Units that have not utilized the 500 ppmv leak definition prior to December 31, 2002, shall enter the program on a quarterly frequency, unless their current interval is shorter.

82. For process units complying with the Sustainable Skip Period Program in Attachment 1, Koch shall use the leak rate determined during an EPA or State inspection to require more frequent monitoring, if appropriate. Koch will utilize the more frequent monitoring program beginning at the start of the next calendar month, provided that if Koch is obligated under applicable regulations to complete its monitoring program for the prior monitoring period and if additional time is required to make the transition, EPA and Koch will agree on a later date to move to the more frequent period. The leak rate determination during EPA or state inspections shall be made based on the total number of leaking valves identified during the inspection divided by

the total number of valves in the process unit that Koch uses to determine the leak rates, rather than the total number of valves monitored during the inspection.

83. Beginning July 1, 2001, Koch shall use dataloggers and/or electronic data storage for LDAR monitoring. Koch can use paper logs where necessary or more feasible (i.e. small rounds, remonitoring when dataloggers are not available or broken, inclement weather, etc).

84. 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.

85. If, during the life of this Consent Decree, Koch completely subcontracts its LDAR program at any of its refineries, Koch shall require its LDAR contractors to conduct a QA/QC review of all data before turning it over to Koch and to provide Koch with daily reports of its monitoring activity.

86. By December 31, 2001, Koch shall have established a program that will hold LDAR personnel accountable for the quality of monitoring and an overall refinery program to provide incentives for leak rate improvements.

87. Koch shall continue to maintain a position within the refinery (or under contract) responsible for LDAR coordination, with the authority to implement these and other recommended improvements.

88. By December 31, 2001, Koch shall have established a tracking program for maintenance records to ensure that components added to the refinery during maintenance and/or construction are added to the LDAR program.

89. Koch shall have the option of monitoring all components within a process unit within 30 days after the startup of the process unit after the turnaround without having the results of the monitoring used in the leak rate determination. Process unit t/a's are considered those activities that are planned on a typical 2-4 year cycle that require a complete unit shutdown.

90. Beginning January 1, 2001, Koch will conduct calibration drift assessments of the LDAR monitoring equipment in accordance with 40 C.F.R. Part 60, EPA Reference Test Method 21 at the end of each monitoring shift, at a minimum. Koch agrees that if any calibration drift

assessment after the initial calibration shows a negative drift of more than 10%, it will remonitor all components since the last calibration that had readings above 50 ppmv.

91. Beginning the first calendar quarter following lodging of this Consent Decree, but no sooner than January 1, 2001, for valves that meet the regulatory requirements to be put on the "delay of repair" list for repair,

(a.) Koch shall require sign-off by the PL (unit foreman) or equivalent or higher authority before the component is eligible for the "delay of repair" list;

(b.) Koch shall set a leak level of 50,000 ppmv at which it will undertake "heroic" efforts to fix the leak rather than put the valve on the "delay of repair" list, unless there is a safety or major environmental concern posed by repairing the leak in this manner. For valves, heroic efforts/repairs shall be defined as non-routine repair methods, such as the drill and tap;

(c.) Koch shall include valves that are placed on the "delay of repair" list in its regular LDAR monitoring, and make "heroic" repair efforts, unless there is a safety or major environmental concern posed by repairing the leak in this manner, if leak reaches 50,000 ppmv; and

(d.) After April 1, 2001, Koch shall undertake heroic efforts to repair valves that have been on the "delay of repair" list for a period of longer than 36 months, unless there is a safety or major environmental concern posed by repairing the leak in this manner.

Recordkeeping and Reporting Requirements For Part VI

92. As part of the progress report submitted pursuant to Part XI, Koch shall submit the following information:

(a.) As part of the first progress report required to be submitted after December 31, 2001, Koch shall include a copy of the written LDAR program for each refinery developed pursuant to Paragraph 75;

(b.) In the first progress report due after the training program required by Paragraph 77 has been implemented at each refinery, Koch shall submit a certification that the training has been implemented;

(c.) In its first progress report due under this Consent Decree, Koch shall submit a certification that the first attempt repair program as described in Paragraph 80 has been implemented;

(d.) As part of the first progress report required to be submitted after July 1, 2001, Koch shall submit a status report on the use of dataloggers

and/or electronic data storage for data monitoring
as required by Paragraph 83;
(e.) In the first progress report submitted after
December 31, 2001, Koch shall include a description of
the equipment standards developed pursuant to Paragraph
84;
(f.) As part of the first progress report submitted after
December 31, 2001, Koch shall include a description of
the accountability/incentive programs that are developed
pursuant to Paragraph 86;
(g.) As part of the first progress report submitted
after December 31, 2001, Koch shall include a
description of the maintenance tracking program developed
pursuant to Paragraph 88;
(h.) As part of its first progress report required by
this Consent Decree, Koch shall submit a certification
that it has implemented the calibration drift assessments
described in Paragraph 90; and
(i.) As part of its first progress report required by
this Consent Decree, Koch shall include a certification
that it has implemented the "delay of repair"
requirements described in Paragraph 91.
93. Koch shall maintain the audit results from Paragraph
78 and any corrective action implemented. The audit results
shall be made available to the EPA and State authorities upon
request.
94. As part of the semiannual monitoring reports
required by 40 C.F.R. Part 63, Subparts H or CC, Koch shall
provide a listing of those units that became subject to the
program described in Paragraph 81 during the reporting
interval. This report shall include the projected date of
the next monitoring frequency for each process unit.