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FLINT HILLS resources®
Corpus Christi Refineries

P.O. Box 2608
Corpus Christi, Texas 78403-2608

March 11, 2014

Ms. Kathleen Aisling
U.S. Environmental Protection Agency, Region 6
Air Permits Section (6PD-R)
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Re: Flint Hills Resources Corpus Christi, LLC - West Refinery
Greenhouse Gas PSD Permit Application
Domestic Crude Project
Response to Information Requests

Dear Ms. Aisling:

On behalf of Flint Hills Resources Corpus Christi, LLC (FHR), I am submitting responses to your January 14, 2014, and January 30, 2014, BACT-related information requests (sent via email) regarding the greenhouse gas (GHG) prevention of significant deterioration (PSD) permit application FHR submitted to EPA Region 6 on December 12, 2012. The permit application seeks to authorize a project at FHR's West Refinery to allow the refinery to process a larger percentage of domestic crude oil (the Domestic Crude Project). Responses to your information request are provided on the following pages. A revised BACT discussion (Section 5.0 of the application) is provided in Attachment A. The revised Appendix B is provided in Attachment B.

In the event you have additional questions or would like to discuss further, please contact Daren Knowles at (361) 242-8301.

Sincerely,

Valerie Pompa
Vice President and Manufacturing Manager

VP/DK/syw
Air 14-100; W 3 N 22

Enclosure

cc: Air Section Manager, TCEQ, Region 14, Corpus Christi, w/enclosure
Mr. Kris L. Kirchner, P.E., Waid Environmental, Austin, w/enclosure
Mr. Jeff Robinson, EPA Region 6, w/enclosure (via email)
Ms. Melanie Magee, EPA Region 6, w/enclosure (via email)

OSHA STAR WORKSITE

RESPONSES TO JANUARY 14, 2014 INFORMATION REQUEST

December 12, 2012, Permit Application

3. **Best Available Control Technology (BACT) for new heaters, Pages 67-68 (also Response to Question #4 in the May 16, 2013, letter from FHR to EPA): Please provide a discussion on why the selected product has the optimal efficiency and why the specific design is BACT. In other words, if 92% is the efficiency of the burner, is an efficiency greater than 92% possible, and if so, why was a design with the higher efficiency not selected as BACT.**

FHR's Response

As outlined in our December 12, 2012, permit application and subsequent submittal on May 16, 2013, refinery heaters of this scale are not off-the-shelf products. They are custom designed to meet a specific application. Optimal efficiency is not determined by selecting a percentage thermal efficiency, and then designing to that. Instead, the heater is designed to include available techniques for improving efficiency, and then estimating the resultant thermal efficiency. For the new Sat Gas No. 3 Hot Oil Heater, by integrating the available techniques for maximizing efficiency, we were able to design a heater with an estimated efficiency of approximately 92%. For the modifications to the existing CCR Hot Oil Heater, implementing available retrofit strategies produces a slightly lower efficiency of 91%.

Note that the 91 or 92% efficiencies we reference are not the estimated combustion efficiencies of the burner. They are instead the estimated thermal efficiency of the heater installations – a measure of how much of the available energy in the fuel is converted into heat that is absorbed by the process.

As provided in our revised BACT analysis (Appendix B), this level of control represents BACT. We found no higher level of control in the RACT/BACT/LAER Clearinghouse or any other source, including the SCAQMD and other California air districts.

Theoretically, higher fired heater efficiency could be obtained by usefully capturing the amount of heat contained in the flue gas. Ideally, if the flue gas could be returned to the same temperature of the ambient elements (air and fuel gas) that supply the combustion process it would be, by definition, 100% efficient. Usually process furnaces have inlet temperatures (on the "process side") well above ambient temperatures so transferring heat from the combustion gases to the process is thermally restricted to no better than this inlet temperature, which leads to less than ideal (100%) heater efficiencies.

Industry has recognized that if the residual heat in the flue gas can be further transferred to the combustion air entering the furnace, a gain in efficiency can be achieved. Heat transfer is always driven by the difference in temperatures (hot side vs. cold side) and as these temperatures begin to approach each other, larger and larger surface areas are required to transfer the heat. To achieve 100% efficiency, an infinite surface area would be required, which is clearly unrealistic. This leads to the question of what is economically reasonable, with the tradeoff being exponentially rising capital costs for gaining infinitesimally smaller amounts of heat.

This theoretical economic analysis quickly becomes irrelevant because the issue of technical feasibility (corrosion) actually dictates the amount of heat that is available to be recovered from the flue gas. The corrosion issue is a result of the flue gas approaching an acidic dew point upon cooling. This dew point is a function of the amount of both moisture and SO_2/SO_3 in the flue gas. The corrosion issue is well documented in technical literature and well understood at the West Refinery as well, and has been the single largest factor leading to early failure of the flue gas/air preheat exchange equipment on our process furnaces.

Because of the potential for corrosion, good engineering practice calls for leaving a safety margin in flue gas temperature above this dew point knowing that there is natural variability in ambient air temperature, the amount of excess air required by a furnace and the sulfur content of the flue gas. We now install skin thermocouples on the metal surfaces near the cold end of the air-preheat equipment to monitor this approach to the dew point and maintain a safe operating margin above it (the method of control is to bypass some of the combustion air around the air preheater). We therefore recover as much heat as is technically feasible without risking damage to the equipment.

For this Project, the estimated process heater thermal efficiency, after having applied the available energy efficiency techniques while maintaining a safety margin to keep the stack exit temperature above the dew point, is approximately 92% for the new Sat Gas No. 3 Hot Oil Heater and 91% for the existing, modified CCR Hot Oil Heater.

RESPONSES TO JANUARY 30, 2014 INFORMATION REQUEST

Carbon Capture Sequestration (CCS) Information

Please provide these items:

6. **Supporting documentation of the estimated CO2 concentration in streams from project combustion. (Page 58 of original application says the streams are "highly diluted.")**

FHR's Response

The CO_2 concentration in flue gas is derived from stoichiometric reactions of oxygen in ordinary air with the carbon contained in the hydrocarbon fuels. Because air consists largely of nitrogen, the CO_2 concentration is "dilute" in the flue gas. Specifically, for the new and modified process heaters the CO_2 concentration is less than 10% for expected operating scenarios, with the exact CO_2 flue gas concentration being a function of the composition of the fuel combusted, the humidity of the combustion air, and the amount of "excess" air required to ensure that combustion is complete. The table below covers a broad range of fuel compositions that cover the range of expected operations.

Flue Gas compositions for ordinary combustion:

FUEL	Propane	Ethane	Methane	50/50 Mix Hydrogen/Methane
Component	Mol%	Mol%	Mol%	Mol%
N_2	71.92	71.59	70.78	69.68
H_2O	14.41	15.26	17.35	20.18
CO_2	**9.81**	**9.29**	**8.02**	**6.3**
O_2	3.00	3.00	3.00	3.00
SO_2	0.00	0.00	0.00	0.00
AR	0.87	0.86	0.85	0.84
Total	100	100	100	100

The above table is based on the following assumptions:
- Combustion air is 70 deg F and 60% relative humidity
- Excess air is added to the combustion process to Ensure that 3% residual O2 remains in the flue gas

The estimated CO_2 concentration for the gas-fired units in this project will fall in a range of 6-10%. By contrast, the concentrations of CO_2 in streams for which EPA determined in its recently proposed Electric Utility GHG NSPS are technically feasible and economical are on the order of 30-32% for coal-fired, IGCC utility boilers. The streams in this project are 3-5 times more dilute.

7. **Adverse environmental impact(s)/air emission estimates associated with CCS scenarios for both non-GHGs and GHGs. (In current application, it is non-specific.)**

FHR's Response

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

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

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

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

8. Water utilization increases and any associated issues that should be considered for the specific site/location such as water availability.

FHR's Response

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

9. Whether or not you explored the availability of an Enhanced Oil Recovery contract? If so, with whom, and what was the response? Did you consider a pipeline to geologic storage or deep water saline injection nearby?

FHR's Response

As set forth in more detail in our revised GHG BACT analysis, we determined that CCS was technically infeasible, in part, because permanent sequestration (including 40 C.F.R. Part 98, Subpart RR compliant EOR) has not been demonstrated. Nevertheless, we estimated the cost of a pipeline to move CO_2 to the nearest, known commercial CO_2 pipeline carrier as part of our overall estimate of the cost of applying CCS to the Project. While that commercial CO_2 pipeline carrier appears to predominantly transport CO_2 for tertiary oil recovery purposes, we did not contact them regarding the possibility of entering an EOR contract.

The basis for relying on a tie in to the nearest commercial CO_2 pipeline is that given the life of the project (evaluated based on up to 20 years), we need to have a long-term commercial outlet if a commitment were made to capture the Project's CO_2 emissions. If we chose to route to a single local, 3rd party EOR operation, the operation of the refinery would be dependent on a single outside operator, and could be impacted by their operational status, the economics of the specific EOR field, and the life of the individual field. It would not be technically or economically feasible to shut the refinery down each time a single EOR operator had a short or long-term interruption.

To estimate the cost of transporting CO_2 to the nearest, known commercial CO2 pipeline carrier, we assumed that we could simply "tap into" a relatively nearby Denbury commercial CO_2 line. Kinder Morgan and Denbury appear to be the largest commercial operators in the CO_2 pipeline business, both predominantly transporting CO_2 for tertiary oil recovery purposes. We had no discussions with either one, but relied on publically available information for locations. As set forth in more detail in our revised BACT analysis, even such a connection to a nearby commercial CO_2 EOR line would not be suitable for long-term geologic sequestration of CO_2 because EPA requires CCS EOR operations to qualify under 40 C.F.R. Part 98, Subpart RR. Using EPA's GHG reporting database, we have found no EOR operators that qualify under Subpart RR.

We did not investigate nearby geologic storage or deep water saline sites because we determined that these options are not technically feasible based on the state of ongoing federally-sponsored and funded demonstration projects. Though the NTEL report identifies geologic formations such as deep water saline injection that *could* sustain geologic sequestration of CO_2, it would be entirely speculative for FHR to acquire rights to such formations, conduct the necessary research and development to assess their suitability for sequestration, develop the injection and monitoring systems, and resolve the outstanding transport, fate, and potentially adverse human health and environmental impacts from CO_2 storage. Accordingly, FHR has not included in its revised application a detailed analysis of such a speculative control technology.

10. A numeric value or percentage for the energy penalty in using CCS. Page 66 states that there will be one, but is not specific.

FHR's Response

The energy requirement associated with using CCS to control CO_2 emissions from this project is estimated to be 350 MMBtu/hr (HHV) of gas (likely from purchased natural gas) needed to fuel the 150# boiler that would be needed to provide the steam required for the amine capture unit and 13.3 megawatts of electricity to power the capture skids, regeneration skids, and the compression associated with CCS. Based on an estimated heat rate of 10,000 Btu/kwh, the electricity consumption requires an estimated 130 MMBTU/hr, bringing the total energy requirement to about 480 MMBtu/hr. As a percentage of the heat input for the sources within the project's scope that would be captured by CCS, this is an estimated 95-100 percentage increase in heat duty.

11. A justification of why the facility needs the additional boiler for the amine capture unit associated with CCS. This discussion should include an energy balance of how much steam the facility can produce (current energy balance) and how much steam the Domestic Crude Project and CCS would use.

FHR's Response

As described below, we are currently very nearly at the limit of boiler steam capacity in the West Refinery;

with the proposed project essentially consuming what excess steam capacity is currently available. Any significant additional steam demand would require us to construct or procure incremental additional steam capacity.

The plant is supplied high pressure steam predominantly from the following sources:

1) The CoGen Unit Waste Heat Recovery Boiler
2) The FCC CO Boiler
3) The Mid Plant Crude Boiler
4) The three utility boilers in the Main Plant (Boilers No. 7, 8, and 9).

Generally, the three utility boilers in the Main Plant and the Mid Plant Crude Boiler are the "swing" producers to balance the demand from all the users. Each of these boilers has a nominal capacity of 90,000 to 130,000 lb/hr of steam. The three utility boilers typically operate between 65,000 lb/hr and 90,000 lb/hr each depending on load demand and season (winter is higher). The Mid Plant Crude Boiler typically operates between 45,000 and 100,000 lb/hr of steam.

The Cogen needs to come off-line for periodic inspection and repair for both "minor" and "major" outages, most of which are scheduled per manufacturer's recommendations and plant experience. When the Cogen comes off line, the other boilers are ramped to nearly their full capacity to make up for the loss, and we implement a steam reduction plan to trim refinery steam consumption to stay in balance, if necessary. For example, the CoGen was down from January 7 to January 31, 2013, and the three utility boilers and the Mid Crude Boiler (sum of the four) averaged 438,000 lb/hr of steam with a peak of 463,000 lb/hr.

In a CCS scenario, CO_2 would be "scrubbed" from the flue gas of the new Sat Gas No. 3 Hot Oil Heater, the modified CCR Hot Oil Heater, and the new utility boiler required to produce steam solely for carbon capture. The heaters and boiler would each have to have their own scrubber. Lean amine (monoethanolamine or MEA) would be circulated through these flue gas scrubber vessels and "capture" the CO_2 from the flue gas. This CO_2-rich MEA from the three scrubbers would then be taken to a common "regeneration" skid. In the regeneration skid, the CO_2 would be stripped from the MEA by using heat in a reboiler. The heating medium would be steam. Moderate temperatures would be required for this heat medium to prevent degradation of the circulating MEA (why we would use steam and not direct heat from a process heater). The steam demand for this regen skid is estimated to be 298,000 lb/hr and the regen skid would become the largest single steam consumer in the refinery. This large new demand would exceed the excess steam capacity following the Project under a normal refinery operating scenario and would leave the refinery severely short on steam when the CoGen is taken offline for maintenance.

12. Facility Operation and Maintenance (O&M) costs without CCS. If the levelized O&M cost in the application on Page 66 is not annual O&M cost for CCS, please provide that number.

FHR's Response

The Operational and Maintenance (O&M) costs provided for CCS in the initial application were annual costs. However, based on our ongoing discussions, we believe that the costs associated with CCS are readily determined to not be economical based on a simple comparison of capital costs for CCS as compared to costs for the project. The capital costs for CCS have been estimated to be approximately \$360 million, which is more than 45% of the approximately \$760 million capital cost of the project.

13. For the equipment on Page 66, state the method used to estimate the costs of these units and provide documentation, if you received vendor quotes.

FHR's Response

We contracted with Mustang Engineering (a major engineering and construction company with significant experience in refining and oil and gas processes) to provide a design for two different generic sizes of carbon capture skids and one generic sized regeneration skid. They provided a preliminary design with preliminary equipment sizing for all the major equipment items associated with the skids. Mustang used their in-house cost estimators to provide a capital cost for these skids. Because Mustang Engineering is in the business of engineering, procurement and construction, they have a continuously updated database of what actual equipment items cost, and these were used to form the basis for major equipment costs. Mustang also used a method of cost estimating called a "factored estimate" whereby a multiplication factor is applied to a best estimate of the sum of the major equipment costs. Mustang applied installation factors to the equipment costs to account for construction labor, bulk material, and detail engineering costs.

This type of estimating is common for screening projects in the early phase of evaluation. During this phase, the level of engineering is very light and many details are unknown. To compensate, good engineering practices require applying a "contingency" to the estimate in recognition that as more engineering progresses, unforeseen details are uncovered which almost always raise the cost of a project. The contingency Mustang applied was 10%, which was an unreasonably small for the level of engineering that was done and the limited actual industrial experience with CCS technology. FHR adjusted the contingency to 25%, which is more reasonable but likely still insufficient, based on the fact that the project would be unique and not commercially proven, and that some trial-and-error as well as post installation work would likely be required to get the technology to be fully functional.

We added cost factors to account for construction management and owner's costs (something the engineering contractor doesn't see and doesn't include in its estimate), consistent with our routine project cost estimation practices. The next adjustment that FHR made was to "right-size" the generic cost estimate to the sizes of the skids that would be required for this project. The method used here was an exponential scaling factor that is common in the industry. A plant that is twice the size or capacity usually isn't twice the cost. There is typically an "economy of scale," if you will. Typical exponential factors for industry range from 0.6 to 0.65. This economy of scale would then say that a plant twice the size is about (2/1)^0.625 or 1.57 times the cost.

Mustang provided the costs for two different size carbon capture skids (one was sized for a furnace that provided 100 MMBtu/hr of heat to a process, the other was sized for a furnace that provided 200 MMBtu/hr of heat to a process). We used this cost data to derive the exponential scaling factor and used it to estimate the cost of skids sized for this project. The resulting exponential scaler was 0.544. Although this value is lower than the typical range, it was applied in our methodology to ensure results consistent with the Mustang work. A higher, more typical value would have resulted in higher cost estimates.

Costs for the additional 150# boiler were estimated based on scaling from a 2008 boiler installation at FHR's East Refinery in Corpus Christi. Actual costs for that project were scaled based on the difference in capacity between the proposed unit and the unit installed, and adjusted for inflation/cost escalation from 2008 to 2014.

14. Are there any technically infeasible aspects of using CCS at the facility due to the fact that the facility is a refinery with numerous existing units?

FHR's Response

As noted in our application, we concluded that CCS was technically infeasible for this Project based on our broader analysis of the state of the multiple technologies that would be needed to complete all aspects of CCS. In addition to the technical feasibility issues identified through that analysis, the West Refinery would be a challenging place to locate the carbon capture facilities required for the Project (more challenging than the typical electric utility, for example) because there are multiple stacks scattered throughout the facility emitting relatively small amounts of more dilute CO_2. The biggest challenge for this project would be to locate CCS capture equipment for the sources to be captured. The scrubbers that would capture CO_2 have very large physical footprints, and the physical constraints for placing the equipment would be an issue, that at the very least would add significant additional costs to the already excessive cost of CCS estimated for this Project.

ATTACHMENT A

Revised BACT (Section 5.0) Discussion

Section 5.0

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) ANALYSIS

Introduction

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

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

Scope of Analysis

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

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

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

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

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

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

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

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

BACT Analysis Methodology

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

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

Step 5: Select the BACT.

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

Step 1: Identify all available control technologies.

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

Step 2: Eliminate technically infeasible options.

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

Step 3: Rank remaining control technologies.

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

Step 4: Evaluate most effective controls and document results.

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

Step 5: Select the BACT.

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

Resources Consulted

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

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

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

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

Clean Fuels

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

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

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

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

Fuel Carbon Content

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

Source-Specific Analysis

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

BACT for Process Heaters

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

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

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

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

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

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

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

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

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

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

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

Carbon Capture and Sequestration (CCS)

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

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

Step 2: Eliminate technically infeasible options.

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

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

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

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

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

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

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

CARBON CAPTURE AND SEQUESTRATION

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

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

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

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

Carbon Capture

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

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

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

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

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

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

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

[11] *Id.* at 35.

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

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

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

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

Carbon Storage

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[23] *Id.*

Carbon Transportation

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

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

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

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

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

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

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

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

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

Step 3: Rank remaining control technologies.

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

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

Step 4: Evaluate most effective controls and document results.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Step 5: Select the BACT.

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

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

Category	Demonstration
Limitations	Greenhouse gas emissions limited to the following tons CO_2e per year on a 365-day rolling total: Sat Gas No. 3 Hot Oil Heater 236,242 tons CO_2e/365-days CCR Hot Oil Heater 62,956 tons CO_2e/365-days An effective means to demonstrate heater operating efficiency is to rely upon the stack exit temperature as a surrogate. Based upon the design of these heaters, maintaining the stack exit temperature below 350 degrees F on a 365-day rolling average basis, excluding periods of heater start-up, shutdown, and low firing rates (<60% of maximum design capacity), over the life of the equipment is indicative of a properly operated heater designed for 92% (Sat Gas No. 3 Hot Oil Heater)/91% (CCR Hot Oil Heater) efficiency.
	Limit excess O_2 in the Sat Gas No. 3 Hot Oil Heater and the CCR Hot Oil Heater exhaust to 4% or less on a 365-day rolling average basis, excluding periods of heater start-up, shutdown, and low firing rates (<60% of maximum design capacity). See Notes 1 and 4.
	Additional work practice standard: In accordance with 40 C.F.R. part 63, subpart DDDDD, conduct annual tune-up (which may include burner inspection and cleaning, flame inspection and optimization, air-to-fuel ratio, and CO optimization as required by subpart DDDDD).
Monitoring Requirements	Maintain compliance with 40 C.F.R. Part 98, Subpart C including flow monitoring of fuel usage and fuel gas analysis.
	Maintain a flue gas temperature monitor to continuously record flue gas exit temperature on each hot oil heater while the heaters are in service.
	Continuously monitor each heater's stack exit temperature. Stack exit temperatures recorded during periods of monitoring

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

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

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

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

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

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

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

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

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

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

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

BACT for Equipment Leak Fugitives

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Step 5: Select the BACT.

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

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

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

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

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

The referenced 28VHP program requires the following:

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

BACT for Cooling Tower

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

Step 1: Identify all available control technologies.

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

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

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

Step 2: Eliminate technically infeasible options.

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

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

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

Step 3: Rank remaining control technologies.

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

Step 4: Evaluate most effective controls and document results.

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

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

Step 5: Select the BACT.

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

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

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

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

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

The referenced permit condition and consent decree read as follows:

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

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

The following cooling towers are subject to this monitoring condition:

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

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

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

Consent Decree:

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

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

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

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

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

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

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

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

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

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

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

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

BACT for Maintenance, Start-up, and Shutdown Emissions

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

Step 1: Identify all available control technologies.

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

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

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

Step 2: Eliminate technically infeasible options.

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

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

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

Step 3: Rank remaining control technologies.

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

Step 4: Evaluate most effective controls and document results.

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

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

Step 5: Select the BACT.

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

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

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

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

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

ATTACHMENT B

Revised Appendix B

Appendix B: GHG BACT Controls and Emission Limits for Process Heaters

This Appendix provides support for the BACT determination made by FHR for process heaters. Where available, a link to the applicable document is provided.

First, the following table summarizes the available BACT determinations for process heaters that are discussed in EPA guidance documents.

Guidance Document	Control Technology
EPA Office of Air and Radiation, "Available And Emerging Technologies For Reducing Greenhouse Gas Emissions From The Petroleum Refining Industry" (October 2010).	Energy Efficient Design: • In general, this document recommends improving process monitoring and control systems; using high efficiency motors; and using variable speed drives. Pp. 19-21. • For process heaters in particular, it recommends using combustion air controls to maintain limits on excess air, and using flue gases to preheat combustion air. P. 24.
EPA Office of Air Quality Planning and Standards, "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011).	This guidance document is not specific to a particular type of facility or emission unit. However, it does provide some considerations and examples applicable to the control technologies identified in FHR's GHG BACT analysis for the process heaters. Energy Efficient Design: • Use of technologies or processes that maximize the energy efficiency of the individual emissions unit. P. 29 • Use of technologies that improve the utilization of thermal energy that is generated and used on site, concentrating on the energy efficiency of equipment that uses the largest amounts of energy. Pp. 30-31 Carbon Capture and Storage: According to EPA, CCS is available as a BACT control technology for "facilities emitting CO2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)." P. 32. The process heaters at the West Refinery do not fit any of the above categories, so FHR has excluded CCS as an "available" control technology for purposes of identifying BACT.

Second, the following table summarizes both numeric emission limits reflecting BACT for GHG issued by permitting authorities in final or draft PSD permits for process heaters, and controls and emission limits proposed by permit applicants, primarily for projects in the petroleum refining or petrochemical manufacturing industries. All of the draft and final permits identified below contain emission limits and do not impose specific control technologies. We reviewed the permit applications and supporting documents for these permits, and we set forth below the control technologies the permitting authorities considered in setting the numeric emission limits. These are the same technologies that FHR has considered in its application. We set forth the status of the permit and the documents reviewed for each facility in parentheses below the facility name. Where available, a link to the applicable document is provided.

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology	Emission Limits
Hyperion Refinery South Dakota Department of Environment and Natural Resources (Final PSD permit issued on 9/15/2012)	Process Heaters (refinery fuel gas)	None specified	• 33.0 tons CO2e per thousand barrels of crude oil received

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
Sinclair Wyoming Refinery EPA Region 8 (Final PSD permit and Statement of Basis – 3/21/2013)	Process Heaters (refinery fuel gas and natural gas)	Energy Efficient Design	• Combustion air preheat • Use of process heat to generate steam • Process integration and heat recovery • Use of excess combustion air monitoring and control	• 146 lb CO2e/MMBtu • 148,946 ton CO2e/yr (crude heater)
		Good Combustion Practices	• Good air/fuel mixing in the combustion zone • Sufficient residence time to complete combustion • Proper fuel gas supply system design and operation • Good burner maintenance and operation • High temperatures and low oxygen levels in the primary combustion zone • Maintaining overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency	
BP-Husky Refining LLC Ohio Environmental	Natural Draft Process Heaters (RFG or natural gas)	Energy Efficient Design	• Enhanced heat recovery (air preheat or convection section)	Crude 1 heaters • 123,562 tpy CO2 (12-month rolling basis)

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
Protection Agency (Final permit issued – 9/20/2013)		Good Combustion Practices	• Use of low-carbon gaseous fuel • Excess air minimization with O2 monitoring and inlet air controls • Periodic burner tuning	Vacuum 1 heater • 82,375 tpy CO2 (12-month rolling basis)
Holly Refining & Marketing Company LLC - Heavy Crude Processing Project Utah Department of Environmental Quality (Final permit – 11/18/2013)	Plant-wide	Efficient Design	• Air preheater package on the Vacuum Furnace Heater	1,003,300 short tons CO2e/year (plant-wide)

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
Valero McKee Refinery – Diamond Shamrock Company EPA Region 6 (<u>Draft permit</u> issued – 8/7/2013)	Vacuum Heater (refinery fuel gas and natural gas) Hydrotreater Charge Heater (refinery fuel gas and natural gas)	Energy Efficient Design	• Combustion air preheat • Use of process heat to generate steam • Process integration and heat recovery • Increase radiant tube surface area when modifying existing heaters • Excess combustion air monitoring and control	Vacuum Heater • 113,043 tpy CO2e • 0.11 lbs CO2/scf Fuel Hydrotreater Charge Heater • 16,711 tpy CO2e • 0.11 lbs CO2/scf Fuel
		Good Combustion Practices	• Good air/fuel mixing in the combustion zone • Sufficient residence time to complete combustion • Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality • Good burner maintenance and operation • High temperatures and low oxygen levels in the primary combustion zone • Overall excess oxygen levels high enough to complete combustion while maximizing thermal efficiency	

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
		Energy Efficient Operating Practices	Minimize GHG emissions by limiting amount of fuel burned based on operational practices, such as: • Initial Heater Tuning and Testing • Conduct annual tune-ups in accordance with 40 C.F.R. part 63, subpart DDDDD • Optimization	
Flint Hills Resources Pine Bend, LLC Minnesota Pollution Control Agency (Final permit – 9/11/2013)	#2 Crude Unit Charge Heater (refinery fuel gas) 23H3 Heater (natural gas) 25H2 Heater (natural gas)	Design and operational energy efficiency measures	• Tune ups to ensure efficient fuel combustion in accordance with NESHAP, 40 CFR pt. 63, subp. DDDDD • Annual stack temperature limits and requirements for corrective actions when 24 hour stack temperatures are above these limits to demonstrate ongoing efficient operation. • Recover incremental heat going to the 25 Vacuum Unit in the form of a new waste heat steam generator 25E38 at the heavy vacuum gas oil • Recover additional propane to the LPG system reducing the carbon intensity of the refinery fuel gas system • The new waste heat steam generator 25E28, additional steam production from 27E120, and reduced steam consumption at the stabilizer reboiler 25E28 fulfills the steam demands of the #3 Crude Unit project without additional steam boiler firing	#2 Crude Unit Charge Heater • 219,660 tpy CO2e • 124.3 lbs CO2e/million Btu heat input 23H3 Heater • 135,795 tpy CO2e • 117.4 lbs CO2e/million Btu heat input 25H2 Heater • 167,066 tpy CO2e • 117 lbs CO2e/million Btu heat input

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
Natgasoline, LLC EPA Region 6 (Revised permit application – 11/6/2013)	Regeneration Heater (natural gas and coke) Methanol-to-Gasoline Reactor Heaters (natural gas) Methanol-to-Gasoline Heavy Gasoline Treater Heater (natural gas)	Energy Efficient Design	• Air preheat system • Energy efficient burners that improve fuel mixing • Heat recovery system that routes flue gas through waste heat recovery system • Increased heat transfer	None
		Good Combustion Practices	• Oxygen monitors and intake air flow monitors can be used to optimize the fuel-to-air ratio and limit excess air • Periodic maintenance and inspections • Use of natural gas as fuel	
Martin Operating Partnership L.P. Refinery Arkansas Department of Environmental Quality (Permit application – 3/8/2013)	Lube Charge Heaters and Stripper Charge Heater	Efficient Combustion Control	• Proper burning tuning • Use of natural gas as fuel • Accurate tuning of process controls	118 lb CO2e/MMBtu

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
Methanex USA, LLC, Geismar Methanol Plant Louisiana Department of Environmental Quality (Final permit– 11/8/2012)	Steam Methane Reformer Heater and Utility Boiler	Energy Efficient Design	• Process integration • Adiabatic pre-reformer • Cogeneration • Use of combustion air and feed/steam preheat • Heat recovery: Waste Heat Steam Generators • New burner designs	0.83 tpy CO_2e per ton methane produced (overall facility limit)
		Good Work Practices	• Maintaining SMR heater as appropriate • Combustion air controls – limitations on excess air • Maintenance and fouling control	
Energy Transfer Partners - Lone Star NGL Mont Belvieu Gas Plant EPA Region 6 (Permit application – 6/5/2012; Final permit – 10/12/2012)	Hot Oil Heaters and Molecular Sieve Regenerator Heaters (natural gas)	Energy Efficient Design	• Combustion air controls – limitations on excess air • Efficient heater and burner design, which improves the mixing of fuel via intelligent flame ignition, flame intensity controls, and flue gas recirculation optimization • Heat recovery using heat exchangers	Hot Oil Heater (per unit): • 138,078 tpy CO_2e • 2,759 lb CO_2/bbl of NGL processed Molecular Sieve Regenerator Heater (per unit): • 23,524 tpy CO_2e • 470 lb CO_2/bbl of NGL processed
		Proper Operation and Good Combustion Practices	• Periodic tune-ups and maintenance • Providing the proper air-to-fuel ratio, residence time, temperature, and combustion zone turbulence • Developing systems for operator practices, maintenance knowledge, and maintenance practices	

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
PL Propylene LLC EPA Region 6 (Final permit and Statement of Basis – 6/10/2013)	Charge Gas Heater and Regeneration Air Heater (natural gas)	Energy Efficient Design	• Heat loss reduction using rigid or blanket insulation • Digital control system to control the heater's operations, including the fuel/air feed and burner operations	Charge Gas Heater • 190,966 tpy CO_2 • 117 lb CO_2/MMBtu heat input Regeneration Air Heater • 102,395 tpy CO_2 • Maintain firebox temperature ≥ 1,000 degrees F
		Good Combustion Practices	• Use of recovered process fuel gas, and proper maintenance following the manufacturer's recommendations to keep the unit running at peak capability to minimize CO_2 formation in the combustion process • Maintain operation of the oxygen trim control. • Calibrate and perform preventative maintenance on the fuel flow meters on an annual basis. • Perform periodic tune-ups of boiler burners. Burners will be visually inspected on an annual basis. • Substitute produced hydrogen that is not sold as product for natural gas to the maximum extent possible in the heater or other existing combustion units at the site	
Targa Gas Processing, Longhorn Gas	Glycol Reboiler, Regeneration	Energy Efficient Design	• Optimize combustion efficiency by ensuring proper air-to-fuel ratio to create more efficient heat transfer.	Annual limits: Glycol Reboiler: • 1,025 tpy CO_2e

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
Plant EPA Region 6 (Final PSD permit and Statement of Basis – 6/17/2013)	Heater, and Hot Oil Heater (natural gas)	Good Combustion Practices	• Proper maintenance and tune-up of the process heaters at least annually per the manufacturer's specifications	Regen Heater: • 6,355 tpy CO_2e Hot Oil Heater: • 50,223 tpy CO_2e Output-based limit: • 1,783.23 lbs CO_2/MMscf (combined limit for the 3 units)
KM Liquids Terminals EPA Region 6 (Final PSD Permit – 5/22/2013; Draft Statement of Basis – 3/28/2013)	Heaters (natural gas)	Energy Efficient Design	• Use of Low Carbon (Natural Gas) Fuel • Designed to maximize heat transfer efficiency and reduce heat loss	• 85% thermal (excluding periods of start-up, shutdown, and malfunction) or use CO_2 CEMS • 116,191 tpy CO_2e per heater
		Good Combustion Practices	• Periodic burner tune-up • Install, utilize, and maintain an automated air/fuel control system to maximize combustion efficiency in the heaters • Excess heat in product streams will be used to pre-heat feed streams throughout the process through the use of heat exchangers to transfer the heat from the product stream to the feed stream	
Alcoa Davenport	Process Heaters (natural gas)	Energy Efficient Design	• Flue gas heat recovery/Economizer • Improved instrumentation and controls	• 117 lb CO_2/MMBtu • 30,270.2 tpy CO_2e

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
Works Iowa Department of Natural Resources (Draft PSD permit and Technical Support Document - 6/18/2012; Final PSD permit – 7/25/2012)		Good Combustion Practices	• Combustion control optimization • Periodic equipment tuning • Workplace manual detailing efficiency improvements	
ONEOK Hydrocarbon, L.P. -- Mont Belvieu NGL Fractionation Plant EPA Region 6 (Draft PSD	Hot Oil Heaters	Energy Efficient Design	• Install Energy Efficient Burners • Draft/Trim Instrumentation and Controls which are used to manage the amount of combustion air available in the heater • Waste Heat Recovery (Economizer / Air Preheater) • Insulation/Insulating Jackets • Reduce air leakage • Reduce slagging and fouling of heat transfer surfaces	• 215,281tpy CO_2e • 14.25 lbs CO_2/bbl y-grade feed for all heaters • Maintain an exhaust temperature of 385 °F or less for each heater

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
permit and Technical Support Document – 5/29/2013; Final PSD permit – 7/23/2013)		Energy Efficient Operating Practices	• Initial Heater Tuning and Testing • Annual Heater Tune-Up • Optimization	
Enterprise Products Operating, Mont Belvieu Complex EPA Region 6 (Final permit and Statement of Basis – 10/12/2012)	Hot Oil Heaters, Reactor Charge Heater, and Regenerant Heaters	Energy Efficient Design	• Insulation to minimize heat loss and heat transfer components that maximize heat recovery while minimizing fuel use • May use CO_2 CEMS and volumetric stack gas flow monitoring system as an alternative to efficiency limit	Hot Oil Heaters (per unit) • 73,058 tpy CO_2e • 160 MMBTU/hr • 140 MMBtu/hr annual average firing rate • 85 % minimum thermal efficiency Reactor Charge Heater • 281,229 tpy CO_2e Regenerant Heaters (per unit) • 14,872 tpy CO_2e • 28.5 MMBtu/hr
		Good Combustion Practices	• Fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf). • Automated air/fuel control system • Routine maintenance, and tune-ups performed as needed	

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
Enterprise Products Operating, Mont Belvieu Complex -- Fractionation Units IX and X EPA Region 6 (PSD Permit application – 2/12/2013)	Hot Oil Heaters and Regenerant Heaters	Energy Efficient Design	• Heater design • Heat Exchangers to pre-heat feed streams.	Hot Oil Heaters (per unit) • Natural Gas/Fuel Gas Use: 73,058 tpy CO2e • Ethane Use: 80,319 tpy CO2e Regenerant Heaters (per unit) • Natural Gas/Fuel Gas Use: 14,872 tpy CO2e • Ethane Use: 16,351 tpy CO2e
		Good Combustion Practices	• Low carbon fuel • Automated air/fuel control system • Preventative maintenance and tune-ups	
ETC Texas Pipeline-Jackson EPA Region 6	Hot Oil Heaters; Trim Heaters; Molecular Sieve Regeneration	Energy Efficient Design	• Burner management system	Hot Oil Heaters • 4,855 tpy CO2e per heater Trim Heaters

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
(Final Permit and Statement of Basis – 5/24/2012)	Heaters; TEG Dehydrator Unit Regeneration Gas Heaters; Stabilization Unit Heater	Good Combustion Practices	• Annual tune-ups, routine maintenance • Optimize combustion efficiency by ensuring proper air-to-fuel ratio to create more efficient heat transfer	• 8,917 tpy CO2e per heater Molecular Sieve Regeneration Heaters • 4,971 tpy CO2e per heater TEG Dehydrator Unit Regeneration Gas Heaters • 1,537 tpy CO2e per heater Stabilization Unit Heater • 2,972 tpy CO2e
Freeport LNG Development, Liquefaction Plant	Process Heaters (natural gas)	Energy Efficient Design	• Use of waste heat recovery in the Combustion Turbine • Efficient heater design	• 100,486 tpy CO2e (group limit)

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
EPA Region 6 (Draft permit issued – 12/2/2013; PSD Permit application - 12/21/2011)		Good Combustion Practices	• Use of natural gas as fuel • Implement good combustion, operating, and maintenance practices • Limit hours of operation for six of the low temperature heaters and the two high temperature heaters to only when the combustion turbine is down for maintenance, approximately 336 hours per year (based on a 12-month rolling total)	
Cargill-Fort Dodge Iowa Department of Natural Resources (Final PSD Permit – 7/16/2012; Revised permit (no changes to GHG BACT) – 8/7/2013)	Process Heater [Permits: 07-A-861-P3; 12-A-158-P]	Efficient Design	• Air preheater • Economizers/heat exchangers • Insulation and air infiltration minimization • Boiler feed water preparation • Boiler blowdown heat exchanger • Condensate return system	• 167,711 tpy CO2e (12-month rolling total) for boiler and process heater
		Good Combustion Practices	• Oxygen trim control • Optimization of the settings for key control variables • Periodic tuning and maintenance	

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
C3 Petrochemicals LLC - PDH Plant, Alvin, Texas EPA Region 6 (PSD Permit application – 2/11/2013)	Process Heaters (fuel gas and natural gas)	Energy Efficient Design	• Operating a heater at near steady state conditions • Efficient burners • Refractory and insulation materials on surfaces to minimize heat loss • Continuous air/fuel control system	None
		Good Combustion Practices	• Use of low carbon fuels • Optimize flame pattern at least annually • Preventative maintenance of the air/fuel control system • Monitor the excess oxygen in the stack of each heater • Periodic tune-ups	
M&G Resins USA , LLC – Project Jumbo EPA Region 6 (PSD Permit application – 2/28/2013)	Process Heaters	Energy Efficient Design	• Use of heat exchanger to recover heat from exhaust gas	320 F exhaust gas temperature
		Good Combustion Practices	• Oxygen trim control • Periodic maintenance of heat transfer surfaces to remove foulant formation • Periodic furnace tune ups	
Equistar Corpus Christi Olefins Plant EPA Region 6	Steam Super Heaters	Energy Efficient Design	• Good Heater design to maximize thermal efficiency • Air/fuel controls • Waste heat recovery/air preheater	73,025 tpy CO2e

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
(Revised PSD Permit application – 10/6/2013)		Good Combustion Practices	• Periodic tune ups • Low carbon fuels	
The Alpha Olefin Chemical Company LLC - Alpha Olefin Plant EPA Region 6 (PSD Permit application – 5/17/2013)	Hot oil heaters	Efficient Design	• Good heater design	None
		Good Combustion Practices	• Use of low carbon fuels and residual alpha olefins • Oxygen trim control • Periodic tune ups	
CCI Corpus Christi LLC - Condensate Splitter Facility EPA Region 6 PSD Permit application – 11/4/2013	Process heaters (natural gas)	Efficient Design	• Efficient burner design with improved fuel mixing capabilities • Increased heat transfer by utilizing state-of-the-art refractory and insulation materials to minimize heat loss and increase overall thermal efficiency • Combustion air preheat system • Heat recovery system that routes the flue gas from the heaters through a heat recovery system • Product heat recovery that transfers heat to the	None

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
			process feedstock and stripping processes by cooling hot product streams in heat exchangers	
		Good Combustion Practices	• Utilize oxygen and intake air flow monitors to optimize fuel/air mixing and limit excess air • Periodic maintenance	
INVISTA S.a.r.l. – Victoria Facility EPA Region 6 (PSD Permit Application – 9/17/2013)	Startup Heater (natural gas)	Efficient Design	• Energy efficient burners that minimize excess air by providing the proper air-to-fuel mixture throughout the full range of firing rates, without constant adjustment • Capture and reuse flue gas to preheat combustion air • Proper insulation to minimize heat loss	None
		Good Combustion Practices	• Instrumentation and controls to monitor and control heater operating parameters such as excess oxygen, carbon monoxide, pressure, combustion air flow, fuel flow, and temperature to optimize efficiency • Reduction of air leakages • Periodic burner tuning and proper equipment	

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
			maintenance and operation • Good fuel/air mixing in combustion zone • Proper fuel gas supply system design and operation • Sufficient excess air	
El Dorado Chemical Company Arkansas Department of Environmental Quality (PSD Permit Application – 1/31/2013; Final permit – 11/18/2013)	Startup heater (natural gas)	Efficient Design and Operation	• Burner tuning • Combustion control through feedback loops that monitor temperature and oxygen levels • Convection section heat recovery to raise thermal efficiency	• 1,115.31 tpy CO2e (12-month rolling average) • 117 lb/MMBtu CO2 (3 hour average) • 0.0022 lb/MMBtu CH4 (3 hour average) • 0.0002 lb/MMBtu N2O (3 hour average)

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
Magnolia Nitrogen Idaho LLC (Magnida) Idaho Department of Environmental Quality (Revised application submitted – 10/2013; Application submitted – 4/2013)	Primary reformer heater (natural gas)	Energy Efficient Design	• Capable of combusting a purge gas stream that contains byproducts of the reforming process (ammonia, nitrogen, hydrogen, inerts and unreacted gases) • Employ an efficient steam system in which high pressure steam is generated from the excess heat generated from the flue gas of the reformer heater	• 579,100 tpy CO2e
		Good Combustion Practices	• Ensure high temperatures, sufficient excess air, sufficient residence times, and good air/fuel mixing to ensure combustion efficiency and energy efficiency	
Midwest Fertilizer Corporation Indiana Department of	Startup heater (natural gas)	Energy Efficient Design	• Proper design, to ensure optimal operation and the minimization of greenhouse gas emissions.	• 59.61 tons CO2/MMCF (three-hour average basis)

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
Environmental Management (Draft permit issued - 1/17/14; Permit application submitted – 8/26/2013)		Good Combustion Practices	• Use of inlet air control sensors that limit excess air and result in optimal combustion.	
ONEOK Hydrocarbon, L.P. – Mont Belvieu NGL Fractionation Plant, Frac-3 and Frac-4 EPA Region 6 (Permit	Hot oil heaters (natural gas, recovered flare gas, and process vents)	Energy Efficient Design	• Install energy efficient burners • Draft/Trim instrumentation and controls which are used to manage the amount of combustion air available in the heater • Waste heat recovery (Economizer / Air Preheater) • Insulation/Insulating jackets • Reduce air leakage • Reduce slagging and fouling of heat transfer surfaces	• 430,628 tpy CO2e (365-day rolling average basis) • Maximum stack exit temperature of 385 degrees F (365-day rolling average basis) excluding periods of start-up and shutdown

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
application submitted – 1/28/2014)		Good Combustion Practices	• Initial heater tuning and testing • Annual heater tune-up • Optimization	
Nuevo Midstream, LLC – Ramsey Gas Plant EPA Region 6 (Permit application submitted – 1/27/2014)	Hot oil heaters and regeneration heaters (natural gas)	Energy Efficient Design	• Install equipment to improve mixing of fuel and creates more efficient heat transfer.	None
		Good Combustion Practices	• Maintain documented operating procedures, updated as required for equipment or practice changes • Maintain operating logs/record keeping • Provide training on applicable equipment and procedures • Conduct routine evaluation, inspection, overhaul as appropriate • Monitor fuel quality and establish fuel handling practices • Adjust air distribution system based on visual	

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
			observations and/or continuous or periodic monitoring	
CHS Inc. – Spiritwood North Dakota Department of Public Health (Permit application submitted – 8/2013)	Urea Plant heater (natural gas)	Energy Efficient Design and Operation	• Combustion control optimization to provide complete oxidation of fuel • Automatic tuning • Digital instrumentation and controls that monitor temperature and/or oxygen levels • Air pre-heaters for preheating combustion air and water heating • Heat recovery equipment, including various types of heat exchangers (economizers and air heaters)	• 117 lbs/MMBtu of heat input • 11,485 tpy CO2e (12-month rolling average basis)

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
Sasol North America Inc., Lake Charles Chemical Complex -- Gas to Liquids Project Louisiana Department of Environmental Quality (Draft permit issued – 2/14/2014; Permit application submitted – 4/30/2013)	Process heaters (natural gas and tail gas)	Good Heater Design	• Efficient burners • More efficient heat transfer efficiency • State-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces • Air preheater to heat the incoming combustion air	• 353,891 tpy CO2e (annual average basis)
		Good Combustion Practices and Proper Burner Design and Operation	• Good control of air/fuel mixing, residence time, fuel supply, optimum temperature, and oxygen levels • Using oxygen and air flow monitors • Periodic tune-ups that include preventative maintenance of fuel gas flow meters and oxygen control analyzers, cleaning of burner tips and convection section tubes	

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
Sasol North America Inc., Lake Charles Chemical Complex -- Cracker Project Louisiana Department of Environmental Quality (Draft permit issued – 2/14/2014; Permit application submitted – 4/30/2013)	Process heaters (natural gas)	Good Heater Design	• Efficient burners • More efficient heat transfer efficiency • State-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces • Air preheater to heat the incoming combustion air	Alcohol Unit Reactor Feed Heater • 9,484 tpy CO2e (annual average basis) Alcohol Unit Hot Oil Heater • 145,933 tpy CO2e (annual average basis)
		Good Combustion Practices and Proper Burner Design and Operation	• Good control of air/fuel mixing, residence time, fuel supply, optimum temperature, and oxygen levels • Using oxygen and air flow monitors • Periodic tune-ups that include preventative maintenance of fuel gas flow meters and oxygen control analyzers, cleaning of burner tips and convection section tubes	

Facility/ Permitting Authority (reviewed document(s))	Emission Unit (fuel type)	Control Technology		Emission Limits
DCP Midstream, LP - - Zia II Gas Plant New Mexico Environment Department Air Quality Bureau (Permit application submitted – 8/1/2013)	Trim reboiler heater, Stabilizer heater, Regenerator gas heater, TEG Regeneration Heater, Hot oil heaters (natural gas)	Efficient Design	• Energy efficient design to ensure proper air-to-fuel ratio • Intelligent flame ignition • Flame intensity controls • Flue gas recirculation	• 117 lb CO_2e/MMBtu (12-month rolling average basis)
		Good Combustion Practices	• Maintain documented operating procedures and operator logs • Train operators on applicable equipment and procedures • Maintain documented maintenance procedures • Routine inspection and maintenance • Tune-ups annually or per manufacturer • Monitor fuel quality with periodic sampling and analysis • Adjust air distribution system based on visual observations and/or continuous or periodic monitoring	