Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for Enterprise Products Operating LLC

Permit Number: PSD-TX-1336-GHG

February 2014

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

I. Executive Summary

On December 18, 2012, Enterprise Products Operating LLC (Enterprise) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions. On June 21, 2012, July 15, 2012, and August 23, 2012, Enterprise submitted additional information to their application. The proposed facility would be a major stationary source. In connection with the proposed project, Enterprise submitted PSD and Non-Attainment New Source Review (NNSR) permit applications for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on December 27, 2012. The project involves construction of a new propane dehydrogenation (PDH) unit at an existing petrochemical complex owned and operated by Enterprise. After reviewing the application, EPA Region 6 prepared the following SOB and draft PSD permit that, when finalized, will authorize construction of new air emission sources at the Enterprise facility.

This SOB provides the information and analysis used to support EPA's decisions in drafting the PSD permit. It includes a description of the facility and proposed construction, the PSD permit requirements based on BACT analyses conducted on the proposed new units, and the compliance terms of the permit.

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

II. Applicant

Mailing Address:
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P. O. Box 4324
Houston, TX 77210

Facility Location:
Enterprise Products Operating LLC
10207 FM 1942
Mont Belvieu, Chambers County, Texas 77580

Contact:
Graham Bacon
Senior Vice President
Enterprise Products Operating LLC (713) 381-5437

III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan (FIP) that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. See 75 FR 25178 (promulgating 40 CFR § 52.2305).

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

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Robert Todd
Air Permitting Section (6PD-R)
(214) 665-2156

IV. Facility Location

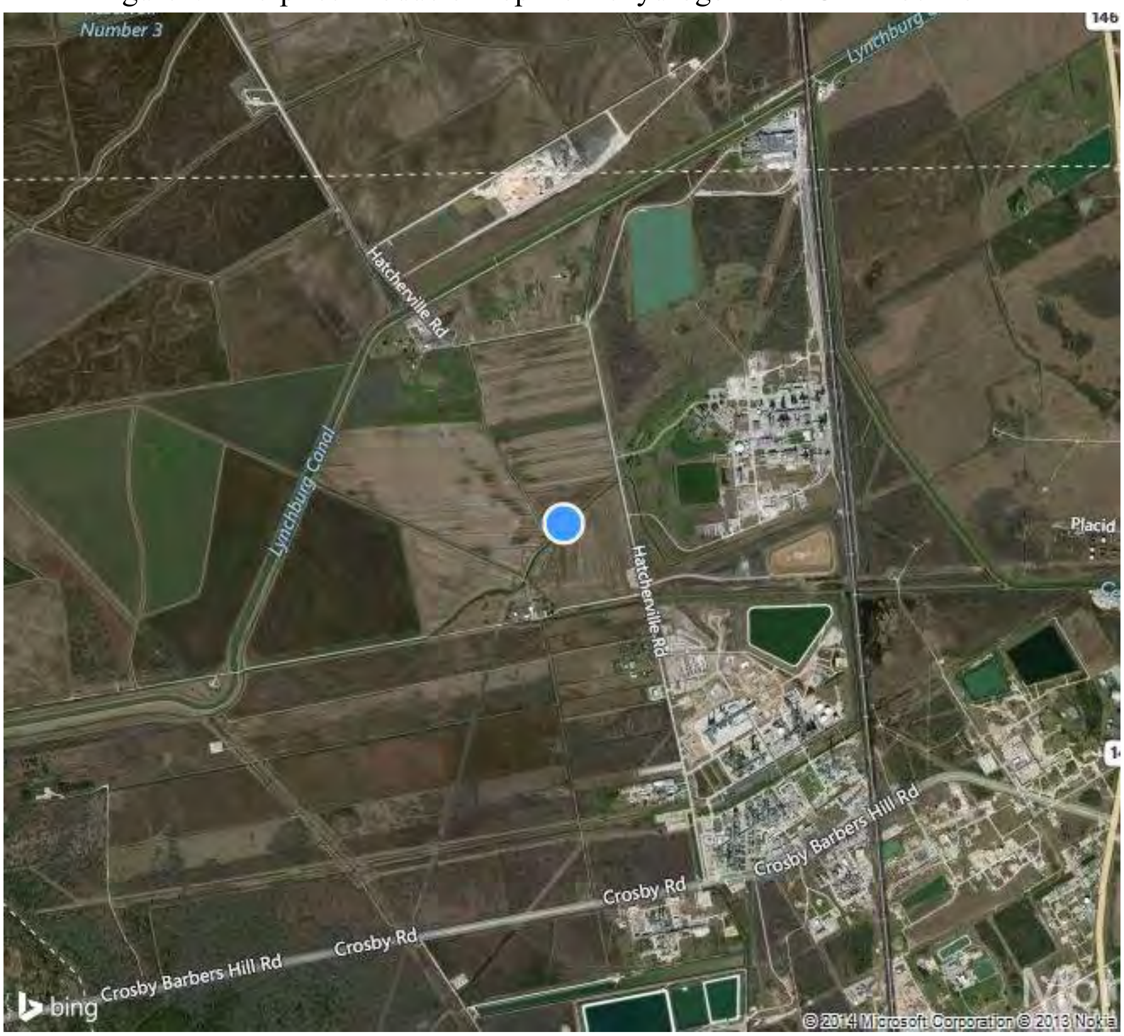
The Enterprise facility is located in Chambers County, Texas. The geographic coordinates for this facility are as follows:

Latitude: 29º 52' 14" North
Longitude: - 94º 55' 23" West

Chambers County is currently designated severe nonattainment for ozone and is currently designated attainment for all other pollutants. The nearest Class I areas are Breton National Wildlife Refuge, approximately 320 miles distant, Big Bend National Park, approximately 480 miles distant, and Guadalupe Mountains National Park, approximately 580 miles distant.

Below, Figure 1 illustrates the location for the proposed project described in this draft permit.

Figure1. Enterprise Products Propane Dehydrogenation Unit Location



V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes Enterprise's application is subject to PSD review for the pollutant GHGs, because the proposed project would result in a net emissions increase of GHGs for a facility as described at 40 CFR § 52.21(b)(23) and (49)(iv). Under the project, GHG emissions are calculated to increase over zero TPY on a mass basis and to exceed the applicability threshold of 75,000 TPY CO_2e (Enterprise calculates CO_2e emissions of 1,342,659 TPY). As noted in Section III, EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

Enterprise represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, will determine that Enterprise is also subject to PSD review for CO, PM, PM_{10}, $PM_{2.5}$, SO_2, NO_x, and sulfuric acid; and NNSR for VOC and NO_x. Accordingly, under the circumstances of this project, TCEQ will issue the non-GHG portion of the permit, and EPA will issue the GHG portion.[1] (At this time, TCEQ, as the permitting authority for regulated NSR pollutants other than GHGs, has not issued the construction permit for non-GHG pollutants. The state issued permit must be in place prior to construction for this applicability analysis and the source's authorization to construct to be valid.)

EPA Region 6 applies the policies and practices reflected in the EPA document "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, and we have not required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions of 40 CFR § 52.21 (o) and (p), respectively. Instead, EPA has determined that compliance with the selected BACT is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules, with respect to emissions of GHGs. The applicant has, however, submitted an analysis to evaluate the additional impacts of the non-GHG pollutants, as it may otherwise apply to the project, to the TCEQ as part of their applications for the PSD and NNSR permits for the non-GHG regulated pollutants as described in the preceding paragraph.

VI. Project Description

Enterprise proposes to construct a new propane dehydrogenation (PDH) unit in Chambers County at its existing oil and gas production facility near Mont Belvieu, Texas. The project will utilize catalytic reactors to convert propane into propylene (the primary product) and hydrogen (a secondary stream). Enterprise expects the unit to be capable of producing propylene in amounts exceeding 1.6 billion pounds each year when operational.

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

The Enterprise facility will consist of ten catalytic reactors, in parallel, to convert the propane feed stock into product; a reactor charge heater to bring the incoming feed stock up to reaction temperature; a regenerative air heater to devolve coke from the catalyst in the reaction vessels; two gas air combustion turbines and two regenerative air compressors set up in parallel to provide air to the regenerative air heater; a waste heat boiler to recover heat and develop steam, as well as help control emissions of CO, VOC and NO_x; a compression and cooling system to cool the product stream and remove condensable fluids; a propylene compression system to isolate the propylene product and move it off the plant site; a pressure swing adsorption/hydrogen recovery unit (PSA) to isolate the hydrogen product stream and move the majority of it off the plant site; two auxiliary boilers to develop additional steam for the process; a cooling tower to control excess heat from the process; ancillary tankage and pumps needed to run the facility; a process flare to provide a safe method to combust feedstock and pressured fuel sources when needed; a wastewater treatment plant to strip out VOCs from waters used in the process; and plant fugitive emissions.

The incoming propane feed stock is passed through the reactor charge heater to increase its temperature to a point where it will react when passed over the catalyst bed. As the heated propane is passing through the catalyst bed, it is converted to propylene and hydrogen streams. Coke (carbon) is deposited onto the catalyst during the reaction. The ten reactors are configured in parallel so Enterprise can purge one reactor with steam and flush a second with heated air and natural gas to remove the coke buildup in the catalyst bed while the production process is continued in the remaining reactors. Each reactor operates in a cycle of propylene/hydrogen production followed by purging and catalyst regeneration. The reactor cycles are sequenced in a manner that permits continuous production and enables an efficient reuse of the heat produced in the process.

The proposed catalyst regeneration system will consist of two gas fired turbines (GT26.101A and GT26.101B) used to drive accompanying air compressors (CM12.101A and CM12.101B) that feed the regenerative air heater (HR15.102). The regenerative air heater raises the temperature of the air to a point where it is able to decoke the catalyst. The heated air is then combined with natural gas, and the mixture is passed through the catalytic reactor beds where it burns off coke deposited on the catalyst during the propylene/hydrogen production cycle. The hot exhaust gases from the catalyst regeneration step and the exhaust from the gas fired turbines is sent to the unit's waste heat boiler (BO10.101) in order to convert the remaining heat energy to steam before being vented to the atmosphere through the boiler's stack (DW37.101).

The initial product exits the reactor train and is compressed to separate out the condensable hydrocarbon liquids from the product stream and move them to storage. The water developed from this system's knock out drums is sent to an onsite wastewater stripper where the hydrocarbons are steam stripped and sent to the reactor charge heater (HR15.101) to be mixed with the fuel stream and combusted. The waste water from the stripper is collected and sent to a wastewater treatment unit off-site. The product stream that exits initial compression enters a closed loop system to dry and separate out the product. The overheads from the product gas dryer are sent to the cold box to become part of the condensation cycle. The product stream itself is sent through deethanizer and sulfur removal units and finally to a product splitter before a propylene compression system sends a portion off-site as high grade propylene. The non product stream from the product splitter is recycled to the front end of the process where it is mixed with the incoming feed stream. The remaining product stream from the splitter, along with the overheads from the deethanizer and product gas dryer, is sent to the cold box unit for chilling and condensation. The vapor stream coming off the cold box is split between the reactor reduction system and the hydrogen recovery/pressure swing adsorption (PSA) unit. A high purity hydrogen product stream is developed in the PSA and sent off-site as final product. Off gases from the PSA are routed to the dryer regeneration system for use in dehydration. Off gas from that unit, in turn, is sent to the fuel gas system. Enterprise represents that the vapor stream sent to the reactor reduction system (RRS) enables better catalyst operation. The spent gases from the RRS are sent to the Waste Heat Boiler (BO10.101) for destruction. Refrigeration for the cold box is provided by a closed loop, motor driven ethylene compression system. The equipment in the cooling, compression and production separation system is in a closed loop configuration and does not represent a source of emission of GHGs, except for process fugitives and the off gas streams that are routed to the fuel system and waste heat boiler, as described above.

Reactor Charge Heater (FIN/EPN - HR15.101)

The Reactor Charge Heater burns plant fuel gas, off gas from the unit wastewater stripper and supplemental natural gas as needed. This heater is used to increase the temperature of the incoming raw material stream to the point where it will react when passed through the catalyst beds. The exhaust from this unit is routed to a selective catalytic reduction unit to control NO_x emissions before being vented to the atmosphere through the reactor charge stack (HR15.101).

Regeneration Air Heater (FIN - HR15.102; EPN - DW37.101)

The regeneration air heater will heat incoming atmospheric air to a temperature sufficient to burn off the coke deposited on the catalyst during the normal production process. The heater is fired with natural gas and process fuel gas. As described above, the exhaust from the heater will be sent to the catalytic reactor beds to decoke the catalyst when in the regeneration cycle and then vented, along with the removed coke, to the waste heat boiler (BO10.101) in order to maximize the efficiency of the heat exchange process.

Waste Heat Boiler (FIN-BO10.101; EPN-DW37.101)

The waste heat boiler (BO10.101) receives exhaust gases from the regeneration air heater (HR15.102) after the catalyst regeneration process and the gas turbine exhaust (GT26.101A and GT26.101B). The excess heat from these two processes and heat supplied by burning plant fuel gas is used for the production of steam. The combustion gases entering and leaving the boiler are passed through catalytic removal beds to control VOC emissions, a catalytic oxidation system to control carbon monoxide and a selective catalytic reduction (SCR) to control NO_x emissions. The boiler is equipped with duct burners (HR15.103) that are fired with plant fuel gas supplemented by natural gas. The duct burners will supply extra steam production beyond what is capable with the recycled heat stream, when needed by the process. The boiler stack will be equipped with a CO_2 continuous emissions monitoring system (CEMS).

Regeneration Gas Turbines /Air Compressors (FIN: GT26.101A/CM12.101A and GT26.101B/ CM12.101B; EPN - DW37.101)

There are two gas turbines (GT26.101A and GT261.1B) driving two air compressors (CM12.101A and CM12.101B) that provide the air stream to the regenerative air heater. The turbine/compressor combinations are designed to be fired with natural gas. During normal operation, the exhaust from the turbines is routed to the waste heat boiler (BO10.101) for heat recovery with the final vent to the atmosphere through the boiler stack (DW37.101). During startup, the turbines' exhaust bypasses the boiler and is vented to the atmosphere from a common stack. This startup mode is represented to account for 21 hours of the plant's yearly operational time.

Auxiliary Boilers (EPN: BO10.103A and BO10.103B)

Two auxiliary boilers, fired by plant fuel gas and natural gas, will be operated to provide steam to the process during times when the main source of steam is inoperable. Enterprise represents each auxiliary boiler will be limited to 310 hours per year of operation at full load. The remainder of the year these boilers will be kept in standby mode, operating at approximately 3.5% of maximum load.

Low Temperature Recovery Unit/Cold Box (LTRU)

After initial compression of the propylene/hydrogen product, the LTRU provides cooling and condensation necessary to make the final propylene and hydrogen product streams. The cold box is the major component of this system. It provides for heat recovery and refrigeration of the product stream. The system is closed loop in configuration and not expected to present a source of GHG emissions except in the form of process fugitive emissions and the off gas streams, described below, that are piped to the fuel gas system.

Cooling Tower

Enterprise indicated they will build a cooling tower to service the PDH unit. Enterprise states that cooling exchange systems using the tower do not have the potential to come into contact with GHGs, either through direct contact or leakage from the process, therefore the cooling tower is not expected to be a source of GHG emissions. Further, Enterprise states that the unit will be subject to Non-Attainment Review by the state of Texas as part of the state permitting process and the unit will have Lowest Achievable Emission Rate technology to monitor for and control volatile organic compounds applied to the unit as part of that review.

Hydrogen Recovery Unit/Pressure Swing Adsorption (PSA)

The PSA unit will isolate and send offsite the hydrogen stream from the process. Tail gases from this unit are sent to the dryer regeneration system and eventually to the plant fuel gas system.

Process Flare (EPN: SK25.801)

Enterprise expects to install a plant flare to service the PDH unit. The flare will be utilized for control of continuous and intermittent emissions associated with the manufacturing process. The flare will continuously burn the system flows from the pump and compressor seals, a purge flow of methane through the flare lines to keep the concentration of oxygen in the system out of the explosive range, and methane to keep the pilot flames lit. These represent minor, routine emission sources at the plant

Emergency Pump Engines (EPN: PM18.803 and PM18.850C)

The plant will have two diesel engines used to power water pumps. One pump is for fire water and another for raw water. Enterprise represents these engines will cause minor GHG emissions, based on scheduled operability testing of 52 hours per year. This amounts to a single one hour test run each week.

Process Fugitives (EPN: FUG-NGAS and FUG-PDH)

There will be fugitive equipment leaks of methane from the unit due to the presence of natural gas used to supplement plant fuel gas. All components containing natural gas will be subject to an inspection and maintenance program to detect and eliminate emissions of methane to the atmosphere.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted by following the "top-down" BACT approach recommended in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) and earlier EPA guidance. The five steps in the "top-down" BACT process are listed below.

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the most effective controls (taking into account the energy, environmental, and economic impacts) and document the results; and,
(5) Select BACT.

VIII. Applicable Emission Units

The majority of the contribution of GHGs associated with the proposed project is from combustion sources (i.e., combustion turbines, heaters, boiler, and the flare). The site has fugitive emissions from piping components which will account for 332 tpy of CO_2e, or less than 0.026% of the project's total CO_2e emissions. The combustion units primarily emit carbon dioxide (CO_2), and small amounts of nitrous oxide (N_2O) and methane (CH_4). The following devices are subject to this GHG PSD permit:

- Reactor Charge Heater (FIN/EPN - HR15.101)
- Regeneration Air Heater (FIN - HR15.102; EPN - DW37.101)
- Waste Heat Boiler Duct Burner (FIN - HR15.103; EPN - DW37.101)
- Regeneration Air Compressor Gas Turbines (FIN - GT26.101A/CM12.101A and GT26.101B/CM12.101B; EPN-DW37.101)
- Auxiliary Boilers (EPN: BO10.103A and BO10.103B)
- Process Fugitives (EPN: FUG-NGAS and FUG-PDH)
- Process Flare (EPN: SK25.801)
- Emergency Pump Engines (EPN: PM18.803 and PM18.850C)

IX. BACT Analyses

A. Post-Combustion Controls

For the proposed project, the streams exiting the Reactor Charge Heater stack (EPN-HR15.101), the Waste Heat Boiler stack (EPN-DW37.101), the Combustion Turbines stack in bypass/startup mode (FIN - GT26101A and GT26101B), the Auxiliary Boiler stacks (EPN - BO10.103A and

BO10.103B) and the Emergency Pump Engines (EPN - PM18.803 and PM18.850C) stacks are capable of considering add-on (post combustion) control technologies that will recover CO_2 from gas streams emitted from combustion units. When in normal operation, the regeneration compression turbines (GT26.101A and GT261.0B) vent to the regeneration air heater (HR15.102) which in turn vents to the reactor regeneration system and on through the waste heat boiler stack (DW37.101). The auxiliary boilers and the emergency pump engines are typically operated in a sporadic or very low load rate. In lieu of considering post combustion or add-on technology as part of the BACT analysis for each of these emission unit types, we consider it here as a combined technology for all the aforementioned emission units.

Step 1 – Identification of Potential Control Technologies for GHGs

Carbon Capture and Sequestration (CCS)

Carbon capture and sequestration is a GHG control process that can be used by "facilities emitting CO_2 in large concentrations, 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)."[2] CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxy-fuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxy-fuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxy-fuel combustion are not considered available control options for this proposed plant. The third approach, post-combustion capture, is applicable to the Reactor Charge Heater and Waste Heat Boiler vents. Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[3]

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[2] U.S. Environmental Protection Agency, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011)

[3] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>, February 2011

Step 2 – Elimination of Technically Infeasible Alternatives

The only available capture technology, post-combustion capture, is believed to be technically feasible for this project.[4]

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

No ranking is needed, since there is only one technically feasible control option.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Carbon Capture and Sequestration (CCS)

Enterprise developed a cost analysis for CCS that provided the basis for eliminating the technology in step 4 of the BACT analysis for the proposed combustion sources listed above. EPA Region 6 reviewed the cost estimate and believes it adequately approximates the cost of a CCS control for this project. The majority of the cost for CCS is attributed to the carbon capture and compression facilities that would be required. The capital cost attributed to construct a post-combustion CCS system for the Enterprise PDH unit is represented to be $1.3 billion. The annualized cost of the system, excluding pipeline or other transport costs, was calculated to be approximately $119 million per year based on a 20 year life of the post-combustion control system at 7% interest. Enterprise based this analysis on a control cost per ton value of $103/ton CO_2 controlled. This value was derived from the 2010 "Report of the Interagency Task Force on Carbon Capture" estimate for industrial sources. Using this value, the estimate of the cost for the CCS approaches the estimated $1.4 billion cost of the PDH unit itself. Therefore, CCS is not an economically viable option for control of carbon emissions at this particular source. The company has also indicated the cost of installing and operating equipment necessary to separate, cool and compress the captured CO_2 would result in significant additional emissions of GHGs, which, if routed to the CCS, would further increase the overall cost of CO_2 control and make this option less cost effective than stated in the application.

This assertion is supported by an analysis stating, in part, that implementation of CCS would increase emissions of NO_x, CO, VOC, PM_{10}, SO_2, and ammonia by as much as 13-17%[5] due to the additional energy required to capture and compress the CO_2. Therefore, we believe that the

[4] Based on the information provided by Enterprise and reviewed by EPA for this BACT analysis, while there are some portions of CCS that may be technically infeasible for this project, EPA has determined that overall Carbon Capture and Storage (CCS) technology is technically feasible at this source.

[5] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Figure 3.7. Available at http://www.ipcc-wg3.de/special-reports/.files-images/SRCCS-Chapter3.pdf

additional energy required and environmental impacts associated with CCS in this non-attainment area are significant.

EPA reviewed Enterprise's analysis and agrees the cost, energy and environmental impacts of implementing CCS for this specific project is not a viable application of BACT.

Step 5 – Selection of BACT

See BACT analyses for the remaining technologies below.

B. Reactor Charge Heater (EPN: HR15.101)

The incoming propane feed stock is passed through the reactor charge heater to increase its temperature before being passed over the catalyst beds. The combustion flue gases from the heater pass through a selective catalytic reduction (SCR) system for NO_x reduction before being exhausted to the atmosphere.

Step 1 – Identification of Potential Control Technologies

- *Periodic burner tune-up* - The burners are tuned periodically to maintain optimal thermal efficiency.
- *Good heater design* – Good heater design to maximize thermal efficiency.
- *Heater air/fuel control* – Monitoring of oxygen concentration in the flue gas on a continual basis for optimal efficiency.
- *Waste heat recovery* – Use of heat recovery from the reactor production stream to preheat the heater feed stream and to produce process steam.
- *Use of low carbon fuels* – Fuels vary in the amount of carbon content for each British thermal unit (btu) consumed, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. Selecting low carbon fuels is a viable method of reducing GHG emissions.
- *Post combustion controls, or Carbon Capture and Sequestration (CCS)* - Section IX.A above provides a description of CCS and EPA's analysis of CCS as BACT for the applicable emission units of this proposed modification.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Use of low/no carbon fuel (such as hydrogen) could result in up to 100% reduction in potential carbon emissions.

- CCS has been rated as up to 90% effective in CO_2 control.
- Heater Design has been rated at up to 10% effective.
- Air and Fuel control has been rated at between 5% and 25% effective.
- Periodic tune-up has been rated at up to 10% for boilers (information not available for heaters).
- Waste heat recovery has variable effectiveness in CO_2 control.

In this type of industrial source, virtually all GHG emissions result from fuel combustion. Plant or process fuel gas (except for the portion of the fuel that is hydrogen) is comprised typically of longer chain, and therefore denser, carbon compounds than the natural gas that is commercially available, and thus results in more CO_2 emissions than natural gas. Burning 100% hydrogen instead of natural gas or plant fuel gas results in 100% control of GHG emissions compared to burning energy equivalents of methane or fuel gas; however, while the GHG emission reduction effectiveness of substituting hydrogen is high, hydrogen is not available for large scale fuel use, so this reduces the effectiveness of this control option.

Good heater design, air/fuel control and periodic tune-ups are considered effective in reducing GHGs, although it is difficult to quantify their overall effectiveness. Since the combination of all of the control options in Step 1, with the exception of CCS, are being proposed by the applicant, a ranking of the individual control options is not necessary.

Heat recovery involving the use of heat exchangers to transfer excess heat contained in one process or product stream to pre-heat feed streams reduces the overall heat input requirement from process heaters. This design is also effective in reducing some process steam requirements, which in turn reduces energy requirements of the overall process. The applicant represents the charge heater will be designed for 85% thermal efficiency.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

CCS - The application of this technology could result in up to 90% control of GHG emissions; however, as stated above in section IX.A, the cost, energy and environmental impact of this technology makes it impractical and an economically unviable option.
Heater Design – A newly constructed heaters can be designed with efficient burners, efficient heater transfer, and state-of-the art refractory and insulation components.

Air/Fuel control – Air/fuel ratio controls will optimize the fuel to air mixture.

Periodic Heater Tune-ups – Perform preventive maintenance of fuel gas flow meters on an annual basis and preventive maintenance of the excess oxygen analyzers quarterly, and clean burner tips and cleaning of convection section tubes on an as-needed basis.

Use of Low Carbon Fuels – Hydrogen from the PSA unit's tail gas (about 60% by volume) combined with ethylene and ethane from the Deethanizer off-gas stream, commercially available ethane and commercially available natural gas are all considered low carbon fuels and are available for use in the heater.

Step 5 – Selection of BACT

To date, other facilities with a similar heater and a GHG BACT limit are summarized in the table below:

Company / Location	Emission Unit	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
PL Propylene Houston, TX	Heater, Charge Gas	Propane Dehydration Unit/ Propylene Production	Energy Efficiency/Good Design & Combustion Practices/Waste Heat Recovery	GHG BACT limit of 117 lb CO_2/MMBtu heat input. 365-day average, rolling daily	2013	PSD-TX-18999-GHG

The charge gas heater in the PL Propylene permit is fired by natural gas and hydrogen. The reactor charge heater proposed by Enterprise will fire off gas from the deethanizer, ethane, and natural gas. The charge gas heater in the PL Propylene permit also has a lower firing rate than the heater proposed by Enterprise. These factors result in the reactor charge heater proposed by Enterprise to have a higher proposed BACT limit. The proposed BACT for the Reactor Charge Heater consists of a combination of the choices listed above. BACT for the heater will consist of:

- *Use of low carbon fuels* - Off gas from the Deethanizer unit, commercially available ethane, and natural gas will be fired in the Reactor Charge Heater. This will result in an overall CO_2e emission rate of about 131 lb CO_2/MMBtu of fuel gas burned in the charge heater. This emission rate is comparable to burning 100% natural gas and, when considering the proposed use of heat capture to preheat the feed stream coming into the charge heater, it results in lower "global" CO_2e emissions compared to burning 100% natural gas and disposing of the off gases produced in the process by other combustion methods.
- *Good heater design* - The heater design will maximize heat transfer efficiency so that the propane feed is evenly heated and heat loss is reduced. Insulating material, such as ceramic fiber blankets of various thickness and density, will be used where feasible.

- *Preheating reactor charge feed* - The heater design will make use of the heat generated in the catalytic reactor beds to preheat the incoming reactor charge feed, thereby reducing the overall energy demands on the system and reducing GHG emissions from the unit.
- *Automated air/fuel control* - Install, utilize, and maintain an automated air and fuel control system to maximize the combustion efficiency of the heater.
- *Preventive Maintenance* - Clean heater burner tips and convection tubes as needed. Calibrate and perform preventive maintenance on the fuel flow meter once per year and the excess oxygen analyzer once per quarter.

The following specific BACT practices are proposed for the charge gas heater:

- Determine CO_2e emissions from the heater based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance. CO_2 emissions shall be determined through the use of a CO_2 CEMS. Demonstrate heater efficiencies by monitoring the exhaust temperature, fuel temperature, ambient temperature, and excess oxygen. Thermal efficiency will be calculated for each operating hour from these parameters using accepted API methods. Charge Heater efficiency of greater than 85% will be maintained on a 12-month rolling average basis, excluding malfunction and maintenance periods. Thermal efficiency will be calculated for each operating hour from these parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4^{th} ed.) Annex G.
- Maintain operation of the air/fuel control system.
- Calibrate and perform preventative maintenance on the fuel flow meters on an annual basis.
- Perform periodic tune-ups of heater burners. Burners will be visually inspected on an annual basis.
- Use low carbon fuels, including the off gas from the Deethanizer unit to the maximum extent possible, as well as commercially available ethane and natural gas to fire the reactor charge heater.

BACT Limits and Compliance:

BACT for the charge gas heater will be a BACT limit of 131.4 lb CO_2/MMBtu heat input on a 12-month rolling average basis. Enterprise shall install, calibrate and operate an O_2 monitor and follow accepted procedures detailed in 40 CFR Part 75 to determine CO2 stack concentrations and mass emissions from the reactor charge heater stack or install calibrate and operate a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2, site specific analysis of process fuel gas, and the actual heat input (HHV). To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations will be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling average, calculated monthly.

An initial stack test demonstration will be required for CO_2 emissions from the emission unit. An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emission are less than 0.01% of the total CO_2e emissions from the heater and are considered a *de minimis* level in comparison to the CO_2 emissions.

C. Regeneration Air Heater (RAH) (FIN: HR15.102; EPN: DW37.101)

The RAH (HR15.102) takes compressed air from the regeneration air compressor gas turbine/ regeneration air compressor trains (GT26.101A/CM12.1.101A and GT26.101B/CM12.1.101B) and heats it to the temperature necessary to regenerate the catalyst in the reactors. The hot regeneration air, containing coke and hydrocarbons, exits the reactor beds and is routed to the waste heat boiler (BO10.101) for steam generation and pollution control.

Step 1 – Identification of Potential Control Technologies

- *Periodic Tune-up* - Periodically tune-up the heater to maintain optimal thermal efficiency.
- *Heater Design* – Good heater design to maximize thermal efficiency.
- *Waste Heat Recovery* – Use of heat recovery from the RAH exhaust to develop steam for use in the process.
- *Use of Low carbon Fuels* – Fuels vary in the amount of carbon per btu, which in turn affects the quantity of CO2 emissions generated per unit of heat input. Selecting low carbon fuels is a viable method of reducing GHG emissions.
- *Post Combustion Controls (CCS)* - Section IX.A provides a description of CCS and EPA's analysis of CCS as BACT for the applicable emission units of this proposed modification.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Based on information provided by the applicant and past experience the potential effectiveness of the control technologies and practices identified can be ranked in the following order.

- Use of low/no carbon fuel (such as hydrogen) could result in up to 100% reduction in potential carbon emissions.
- CCS has been rated as up to 90% effective in CO_2 control.
- Heater Design has been rated at up to 10% effective.
- Air and fuel control has been rated at between 5% and 25% effective.
- Periodic tune-up has been rated at up to 10% for boilers (information not available for heaters).
- Waste heat recovery has variable effectiveness in CO_2 control.

Substitution of hydrogen for natural gas (methane) or other components of plant fuel gas (in this case, ethane and ethylene driven off the PSA unit) result in 100% control of GHG emissions that would otherwise be emitted by each pound of carbon based fuel replaced; however, while the GHG emission reduction effectiveness of substituting hydrogen is high, hydrogen is not always available for use. The other potential downside of this technique is that using increasing volumes of hydrogen as a fuel source will inevitably increase the emissions of heat-generated nitrogen oxides into the atmosphere.

Post Combustion controls are examined, and rejected, as an option in section IX.A above.

Waste Heat Recovery as a method to reduce GHG emissions cannot be easily evaluated due to the changing fuel mix available for use in the process and the variable efficiencies each fuel source is expected to demonstrate in producing the steam load required by the plant. The existence of heat recovery as a technical feature of the proposed process inherently increases the overall efficiencies of the process and presents a viable option to reduce the production of GHG gases from the process.

Good heater design is represented to achieve at least a 10% increase in efficiency of the process.

Periodic tune-ups of the heater are considered effective in increasing the efficiency of the burners and thereby reducing GHG emissions from the heater, but the efficiency achieved has not been characterized in the literature.

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

Waste heat recovery by venting the hot gases from the RAH through the waste heat boiler is represented to be the most effective form of control of GHG emissions, because it results in an overall reduction in demand for fuel burning within the plant. Use of low carbon fuels, such as hydrogen from the PSA Tail Gas, ethane and ethylene from the deethanizer unit, and commercially available natural gas, will significantly reduce the carbon released into the atmosphere from the heater when compared to the possible emission if other methods of heat generation are applied. Efficient Heater Design that maximizes heat transfer and minimizes heat loss, along with periodic tuning of the heater section of the Regenerative Air Heater, is the next most effective way to reduce the fuel demand and, therefore, the GHGs emitted to the atmosphere. The applicant proposes to add good combustion control practices as a control technology.

With the exception of CCS, Enterprise proposes to employ a combination of the methods described in steps 1 and 3, above. Therefore, a formal ranking of the options is not necessary for purposes of this analysis.

Step 5 – Selection of BACT

To date, other facilities with a similar heater and a GHG BACT limit are summarized in the table below:

Company / Location	Emission Unit	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
PL Propylene Houston, TX	Heater, Air	Propane Dehydration-Propylene Production	Energy Efficiency/ Good Design & Combustion Practices/Waste Heat Boiler	Regeneration Air Heaters - Maximum firing rate 200 MMBtu/hr. Maintain >1000 °F firebox temperature	2013	PSD-TX-18999-GHG
Enterprise Products Operating LLC Mont Belvieu, TX	Heater, Air	Eagleford Fractionation and DIB unit modification.	Use of Good Combustion Practices.	Regenerant heaters - Maximum firing rate 28.5 MMBtu/hr per unit.	2012	PSD-TX-1286-GHG
Energy Transfer Partners, Lone Star NGL Mont Belvieu, TX	Heater	NGL Fractionation	Energy Efficiency/ Good Design & Combustion Practices	Regenerator Heaters (46 MMBtu/hr) BACT Limit 470 lbs CO_2/bbl of NGL processed.	2012	PSD-TX-93813-GHG

In the case of the regenerative air heater, BACT is determined to be a combination of good heater design, preventive maintenance, good combustion practices, waste heat recovery and use of low carbon fuels. Specifically, the applicant will use, to the extent possible, low carbon fuels such as the hydrogen from the PSA tail gas and ethane and ethylene from the deethanizer unit before using commercially available natural gas to fire the heater. The applicant proposes to determine compliance with a CO_2e limit based on the rate of fuel firing, use of standard emission factors and/or fuel composition and mass balance. The applicant will design the regenerative air heater, the catalyst regeneration cycle and the waste heat boiler so as to maximize heat transfer efficiency, reduce heat loss in the system and reduce the amount of plant fuel and commercially obtained natural gas needed to produce plant steam. The hot spent air will be routed from the catalyst beds during regeneration through the waste heat boiler to recover as much heat as possible through steam production. The applicant will install, utilize and maintain in good working order an automated fuel control system to maximize the combustion efficiency of the heater. Good maintenance practices will be used to keep the heater's burner tips clean. The fuel flow meter will be calibrated and have preventive maintenance performed on yearly basis.

During normal operations, the two gas turbine/compressor trains (GT26.101A/CM12.101A and GT26.101B/CM12.101B) will provide air to the direct-fired regeneration air heater (HR15.102), which in turn will vent to the reactor regeneration cycle and finally through the waste heat boiler (BO10.101). The two combustion turbines (GT26.101A and B) will vent their exhaust directly to the waste heat boiler (BO10.101) for heat recovery. Since the gas turbines, regeneration air heater and the waste heat boiler have a common vent to the atmosphere in normal operation, these units will have a combined BACT limit of 132.0 lbs CO_2/MMBtu, including the heat value of the natural gas added to the reactor regeneration cycle. The waste heat boiler stack will be equipped with a CO_2 continuous emissions monitoring system (CEMS) to monitor for BACT compliance. Compliance with BACT will be based on the CO_2 emissions as measured by the CO_2 CEMS, the fuel usage monitors and standard heat values for the components of the fuel gas.

The following specific BACT practices are proposed for the regeneration air heater:

- Determine CO_2e emissions from the heater based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance.
- Maintain operation of an automated fuel control system to maximize combustion efficiency.
- Calibrate and perform preventative maintenance on the fuel flow meters on an annual basis.
- Perform periodic tune-ups of heater burners. Burners will be visually inspected on an annual basis.
- Use low carbon fuels, including the hydrogen laden tail gas stream from the PSA unit, the off gas from the Deethanizer unit to the maximum extent possible, as well as commercially available ethane and natural gas to fire the heater.

The burner and firebox will be physically inspected annually either with a bore-scope or visually through inspection ports to see if there is any burner damage or unusual flame patterns which would indicate poor combustion and therefore higher CO_2 emissions.

D. Waste Heat Boiler/Duct Burner (FIN: BO10.101 (WHB) and HR15.103 (Duct Burner); EPN: DW37.101)

Hot gases from the catalyst regeneration step (coke burn and natural gas combustion products) are mixed with effluent from the Reactor Reduction system and then passed through the waste heat boiler to recover the heat from the gas stream and generate steam. The waste heat boiler is equipped with volatile organic compound removal beds (oxidation catalysts), the waste heat combustion unit (HR15.103), which are duct burners used on start up and when supplemental heat is needed, and a heat recovery steam generator. Supplemental fuel (natural gas and process fuel gas) is used to get the steam to the proper pressure and temperature for use in plant operations. The combustion gases leaving the boiler pass through a selective catalytic reduction (SCR) unit to control NO_x emissions. Hot volatile organic off gases and coke emissions (carbon) generated during the reactor regeneration process are routed through the waste heat boiler for energy capture and venting.

Step 1 – Identification of Potential Control Technologies

Potential methods to control GHG emissions from this unit are:

- *Good combustion practices and routine boiler maintenance* – The applicant represents that periodically tuning up the boiler will provide up to a 10% increase in the thermal efficiency of the boiler.
- *Waste Heat Recovery* – The boiler is designed to maximize recovery of heat generated by the by the regenerative air heater and catalyst regeneration system. The applicant represents this as a potential 90% GHG control efficiency.
- *Good boiler design* – Good design is represented to provide up to a 26% increase in the thermal efficiency of the boiler.
- *Use of low carbon fuels* - Partial replacement of natural gas (methane) with hydrogen (produced as a product in the reaction process) reduces CO_2 emissions since combustion of hydrogen does not produce CO_2.
- *Post Combustion Controls (CCS)* - Section IX.A provides a description of CCS and EPA's analysis of CCS as BACT for the applicable emission units of this proposed modification.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified above are considered to be technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- *Use of low carbon fuels* – This option could reduce the production of GHGs from the process by as much as 100% if only hydrogen is burned in the system, but the potential efficiency will vary considerably with the availability of fuels, as discussed earlier in this statement of basis.

- *Waste Heat Recovery* – The boiler is designed to maximize recovery of heat generated by the by the regenerative air heater and catalyst regeneration system. The applicant represents this as a potential 90% GHG control efficiency.
- *Post Combustion Controls (CCS)* - Section IX.A provides a description of CCS and EPA's analysis of CCS as BACT for the applicable emission units of this proposed modification. It is thought that a 90% reduction in GHG emissions is possible with this control option.
- *Good boiler design* – Good design of the boiler is represented to provide up to a 26% increase in thermal efficiency of the boiler.
- *Routine boiler maintenance* – The applicant represents that periodically tuning up the boiler will provide up to a 10% increase in the thermal efficiency of the boiler.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Since the combination of all of the control options in Step 3, with the exception of CCS, which is not included for reasons explained above, are being proposed by the applicant, there is no need to further evaluate the economic, energy and environmental impacts of each on this proposed project. It is important to note that the substitution of hydrogen for fuel gas or natural gas may cause an increase in NO_x emissions due to a higher flame temperature and reduced flame stability in the burner.

Step 5 – Selection of BACT

To date, other similar facilities with a GHG BACT limit are summarized in the Table below.

Company / Location	Emission Unit	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
PL Propylene Houston, TX	Waste Heat Boiler	Propane Dehydration-Propylene Production	Energy Efficiency/ Good Design & Combustion Practices	Waste heat boiler/duct burners – CO_2 CEMS and 117 lb CO_2/MMBtu heat input. 365-day average, rolling daily	2013	PSD-TX-18999-GHG

BACT for the boiler will consist of use of the latest technical designs for the units, 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. The duct burners will meet a design efficiency factor of 118.5 lb

CO_2/MMBtu heat input when fired with natural gas. In addition, the burner and firebox will be physically inspected annually either with a bore-scope or visually through inspection ports to see if there is any burner damage or unusual flame patterns which would indicate poor combustion and therefore higher CO_2 emissions.
The following specific BACT practices are proposed for the waste heat boiler (BO10.101):

- Design the duct burners to be capable of a CO_2 BACT performance limit of 118.5 lb CO_2/MMBtu heat input on a 12-month rolling average basis when burning natural gas.
- Maintain a CO_2 BACT limit of 126.5 lb CO_2/MMBtu (determined by dividing the measured emissions from the vent by the total heat input to the waste heat boiler) heat input on a 12-month rolling average basis when using fuel gas. This limit includes the CO_2 expected to be generated as part of the reactor regeneration cycle and for which the company does not represent a heat input value. Therefore, the 132 lb CO_2/MMBtu is appropriate in this specific circumstance.
- Design the boilers to use waste heat recovery to provide an estimated 95% of the boiler's energy requirements.
- Use an O_2 stack monitor and follow accepted procedures detailed in 40 CFR Part 75 to determine CO2 stack concentrations and mass emissions from the waste heat boiler stack or install calibrate and operate a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.
- Determine CO_2e emissions from the heater based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance. Use good boiler design to maximize heat transfer efficiency and reduce heat loss.
- Install, utilize and maintain an automated fuel control system to maximize combustion efficiency within the boiler.
- Calibrate and perform preventative maintenance on the fuel flow meters on an annual basis.
- Perform periodic tune-ups of boiler burners. The burners will be visually inspected on an annual basis. Clean burners as needed when visual or bore scope inspections indicate blockage of any burner component.
- Use low carbon fuels, including the hydrogen laden tail gas stream from the PSA unit, the off gas from the Deethanizer unit to the maximum extent possible in the duct burner, as well as commercially available ethane and natural gas to fire the duct burner.

E. Regeneration Air Compressor Gas Turbines (FINs: GT26.101A and GT26.101B, EPN:DW37.101)

The gas turbines drive the air compressors needed to generate hot compressed air for the regeneration (or decoking) of the dehydrogenation catalyst in the reactors. These regeneration air compressor gas turbine trains provide large volumes of air to be heated by the regenerative air heater (HR15.102) that are needed to burn coke off the catalyst.

Step 1 – Identification of Potential Control Technologies for GHGs

Potential methods to control GHG emissions from this unit are:

- *Good turbine design* – Good design is represented to provide the most efficient heat transfer possible in this equipment and, therefore, the greatest reduction in CO2 emissions through improved thermal efficiency.
- *Good combustion practices* - The applicant represents that limiting the amount of excess air provided to the turbines will improve the efficiency of the turbines, reduce the fuel requirements and thereby reduce the CO2 emissions from the turbines.
- *Preventive Maintenance and Periodic Tune-ups* – Periodically tuning up the turbines by implementing a preventive maintenance program on the fuel gas flow meters, tuning the air flow to the turbines and cleaning the burner will provide an indeterminate increase in the thermal efficiency of the boiler.
- *Waste Heat Recovery* – Venting the exhaust from the turbines to the waste heat boiler is an effective way to maximize recovery of heat generated by turbines. The applicant represents waste heat recovery as a potential 90% GHG control efficiency on the process as a whole and recovering the turbines' waste heat is a significant part of the efficiency.
- *Use of low carbon fuels* - Natural gas (methane) is the lowest carbon fuel available to fire the turbines.
- *Post Combustion Controls (CCS)* - Section IX.A provides a description of CCS and EPA's analysis of CCS as BACT for the applicable emission units of this proposed modification.
- *Limit MSS conditions through good operation practices* – During MSS, the exhaust gas from the turbines is vented to the atmosphere instead of being sent to the waste heat boiler. Enterprise will use good operational practice to limit the MMS conditions to 21 hours per year measured on 12 month rolling basis.

***Step 2** – Elimination of Technically Infeasible Alterna*tives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Post Combustion Control (CCS) is addressed in Section IX.A above. While effective in capturing and sequestering up to 90% of the carbon produced, CCS will not be cost effective in this situation.

Since the combination of all of the control options in Step 3, with the exception of CCS, are being proposed by the applicant, there is no need to further evaluate the economic, energy and environmental impacts of each on this proposed project. It is important to note that the substitution of hydrogen for fuel gas or natural gas may cause an increase in NO_x emissions due to a higher flame temperature and reduced flame stability in the burner.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Since the combination of all of the control options in Step 1, with the exception of post combustion controls, are being proposed by the applicant, there is no need to evaluate the economic, energy and environmental impacts of the control options on the proposed project.

Step 5 – Selection of BACT

To date, other similar facilities with a GHG BACT limit are summarized in the Table below.

Company / Location	Equipment	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
PL Propylene LLC	Turbine, Combusiton, Heated Air, Only	Propylene Production	Use of Good Combustion Practices	117 lbs CO_2/MMBtu	2013	PSD-TX-18999-GHG
Copano, Houston Central Gas Plant Houston, TX	Turbine Combustion Compression	NGL Fractionation	Energy Efficiency/ Good Design & Combustion Practices	Minimum 40% thermal efficiency with waste heat recovery 12-month rolling average	2013	PSD-TX-104949-GHG
Cheniere Corpus Christi Pipeline, Sinton Compressor Station Sinton, TX	Turbine Combustion Simple Cycle (except 4 have WHRU)	Natural Gas Pretreatment Facility	Energy Efficiency/ Good Design & Combustion Practices	0.91 lb CO_2/hp-hr 12-month rolling average	*	PSD-TX-1304-GHG

*Permit not yet issued.

These gas combustion turbines are supplying heated air to the production process and hot exhaust from the turbines to the waste heat boiler. For the purpose of comparing BACT limits, EPA has not been able to identify any previous GHG PSD permits that identify comparable units using this type of heat recovery technology. One propane dehydration unit using combustion turbines was previously permitted and is identified in the Table above. All the other GHG permitted combustion turbines were for energy generation or general compression purposes.

The following specific BACT practices are proposed for each gas turbine:

- *Waste Heat Recovery* – The applicant proposes to recover waste heat from both turbine exhausts to the maximum extent possible in the waste heat boiler in order to produce steam for the plant processes. This will reduce the overall GHG emissions from the unit as a whole.
- *Use of low carbon fuel* – Commercially available natural gas is the only fuel useful in firing the turbines. Enterprise proposes this as part of their BACT for this unit.
- *Combustion Unit Design* – The combustion turbines will be designed to maximize heat transfer and minimize heat loss.
- *Preventive Maintenance* – Enterprise will perform preventive maintenance on the turbines as necessary. This will include calibration and needed maintenance on the fuel flow meter at least once per year.
- *Periodic tune-ups* – Enterprise will tune the air flow in the turbine and clean the burner tips as necessary in order to maintain efficient performance of the turbines.
- *Limit MSS conditions through good operation practices* – Enterprise will use good operational practice to limit the startup conditions of the turbines and diversion of the combustion exhaust through the bypass stack directly to the atmosphere to 21 hours per year measured on a 12-month rolling total basis.

BACT Limits and Compliance:

During normal operations, the gas turbines (GT26.101A and GT26.101B) will vent to the waste heat boiler (BO10.101). Since the units vent to a common manifold or stack/vent at the waste heat boiler, these units will have a combined BACT limit as discussed below. These units combined (GT26.101A, GT26.101B, HR15.102, and BO10.101 venting through EPN DW37.101) will have a BACT limit of 126.5 lbs CO_2/MMBtu, determined by dividing the measured emissions from the vent by the total heat input to the waste heat boiler. In order to demonstrate compliance with the BACT limit, the waste heat boiler stack (EPN DW37.101) will be equipped with an O_2 monitor to determine CO2 stack concentrations and mass emissions from the waste heat boiler stack following accepted procedures detailed in 40 CFR Part 75 or a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

BACT for the gas turbines will be to use the latest technical design for the units coupled with proper maintenance to keep the units running at their peak capacity. In addition, waste heat recovery derived from venting the exhaust through the boiler, maximizing steam production and reducing the need to fire additional fuels at other points in the process is a major design feature of the plant. Such efficient operation will minimize CO_2 formation in the PDH plant's combustion processes. Enterprise, in a confidential exchange with EPA, represents this design and other waste heat recovery operations in the proposed plant will produce propylene at an energy usage significantly below the published industry standard for thermal cracking of propylene of 12,000 Btu per pound of propylene produced. Periodic preventative maintenance and routine monitoring of operating variables will assure that the units operate as designed.

Enterprise will demonstrate compliance with the CO_2 emission limit for the combustion turbines during normal operations and during periods of maintenance, startup, and shutdown (MSS). Enterprise will demonstrate compliance with the CO_2 emission limit established for the MSS emissions from the combustion turbines based on metered fuel consumption and using the default CO_2 emission factor for natural gas from 40 CFR Part 98 Subpart C, Table C-1 and/or fuel composition and mass balance. The equation for estimating CO_2 emissions as specified in 40 CFR § 98.33(a)(2)(i) is as follows:

$$CO_2 = 1x10^{-3} * Fuel * HHV * EF * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to 40 C.F.R. § 98.3(i).
HHV = Annual average high heat value of the gaseous fuel (MMBtu/scf). The average HHV shall be calculated according to the requirements at 40 C.F.R. § 98.33(a)(2)(ii).
EF = Fuel-specific default CO_2 emission factor from Table C-1 of this subpart (kg CO_2/ MMBtu).
$1x10^{-3}$ = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on November 29, 2013 (78 FR 71904). Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a rolling 12-month average.

F. Auxiliary Boilers (FIN/EPN: BO10.101A and BO10.101B)

Two auxiliary boilers, fired by plant fuel gas and natural gas, will be operated to provide steam to the process during time when the main sources of steam are inoperable. The company represents each auxiliary boiler will be limited to 310 hours per year of operation at full load—approximately 4% of the plant's operating schedule. The remainder of the year these boilers will be kept in hot standby mode, operating at approximately 3.5% of maximum load. It is necessary to keep these boilers in hot standby mode so that they can be brought on line very quickly when needed. This operational feature is projected to reduce the restart time of the plant after an upset or malfunction event, which in turn will significantly reduce the amount of uncontrolled GHG emissions expected after such an event.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Good combustion practices* - Improved process controls, reduction of flue gas quantities and reducing excess air.
- *Good boiler design* – Good design is proposed to maximize thermal efficiency.
- *Low standby operation* – Keeping the standby operation mode at 3.5% of maximum load will reduce the total quantity of GHGs emitted to the atmosphere when compared to keeping the boilers at full load when on standby.
- Routine boiler maintenance – Periodically tune-up the boilers to maintain optimal thermal efficiency,
- *Use of low carbon fuels* - Partial replacement of natural gas (methane) with hydrogen (produced as a product in the reaction process) reduces CO_2 emissions since combustion of hydrogen does not produce CO_2.
- *Post Combustion Controls (CCS)* - Section IX.A provides a description of CCS and EPA's analysis of CCS as BACT for the applicable emission units of this proposed modification.

Step 2 – Elimination of Technically Infeasible Alternatives

All options listed above are technically feasible for these boilers.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The effectiveness of the options presented above are ranked in the following order:

- CCS is capable of capturing and storing approximately 90 % of the GHG emitted from these units.
- Use of Low Standby operating rates. Operating the auxiliary boilers at approximately 3.5% of maximum load and only using them when needed to supplement the steam provided by the waste heat boiler (normally at startup and when the primary sources of steam are not available) will reduce the potential GHG emissions by greater than 90% compared to keeping them at 100% of capacity.
- Good boiler design is projected to increase thermal efficiency up to 26%.

- Use of air and fuel controls to provide up to 1% improved efficiency for each 15% of excess air kept of the system.
- Routine, planned maintenance tune-ups of the boilers should provide up to 10% increased efficiency of the boilers.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

- CCS is evaluated is Section IX.A above and found to be economically infeasible.
- Low standby operating rates will minimize GHG emissions compared to the potential.
- Good boiler design is practical and effective.
- Air to fuel controls to maximize thermal efficiency in the firing of the boilers.
- Periodic boiler maintenance tune-ups including preventative maintenance of the fuel gas meters on a annual basis, preventive maintenance check of the excess oxygen analyzers on a quarterly basis and cleaning of the convection section tubes as needed will improve thermal efficiency of the auxiliary boilers up to 1.5% according to Enterprise and can be expected to reduce GHG emissions.

Step 5 – Selection of BACT

To date, other similar facilities with a GHG BACT limit are summarized in the Table below.

Company / Location	Equipment	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
La Paloma Energy Center	Auxiliary Boiler	Energy Generation	Good combustion Practices	Firing limited to 876 hours per year/fuel limited to natural gas	2013	PSD-TX-1288-GHG

While CCS has been determined to be economically infeasible at this time, the other proposed control techniques, along with the use of low carbon fuels when available, can all be applied to reduce GHG emissions.

- Good boiler design to maximize heat transfer efficiency, reduce heat loss and that allows operation at14 MMBtu/hr is proposed.
- Limit operation of the auxiliary boilers to 14 MMBtu/hr when in hot standby mode and 310 hrs/yr each at full load calculated on a 12-month rolling total.
- Use low carbon fuels, including the hydrogen laden tail gas stream from the PSA unit, the off gas from the Deethanizer unit to the maximum extent possible, as well as commercially available ethane and natural gas to fire the heater.

- Install, utilize and maintain automated air/fuel control systems on each boiler to maximize combustion efficiency.
- Clean heater burner tips and convention tubes as needed.
- Perform preventive maintenance and calibrate the fuel flow meters once per year.
- Perform preventive maintenance and calibrate the excess oxygen analyzers as needed, but at least once per quarter. Use low carbon fuels, including the hydrogen laden tail gas stream from the PSA unit, the off gas from the Deethanizer unit to the maximum extent possible, as well as commercially available ethane and natural gas to fire the heater.

G. Fugitive Process Emissions (FIN/EPN: /FUG-PDH & FUG-NGAS)

Hydrocarbon emissions from piping components in the process (EPN FUG-PDH) and in the natural gas supply pipeline (EPA FUG-NGAS) associated with this project include methane, which is a GHG with a global warming potential (GWP) of 25. The CO_2e from the FUG-PDH fugitive emissions area calculated to be 5 TPY; the CO_2e from FUG-NGAs are calculated to be 274 TPY.

Step 1 – Identification of Potential Control Technologies

- *Leakless/Sealless Technology*
- *Instrument Leak Detection and Repair (LDAR) Programs*
- *Remote Sensing*
- *Auditory/Visual/ Olfactory (AVO) Monitoring*
- *Use of High Quality Components and Materials*

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Leakless technologies are effective in eliminating fugitive emissions from valve stems and flanges, though there are still some areas where fugitive emissions can occur (e.g. relief valves).

Instrument monitoring (LDAR) is effective for identifying leaking components and is an accepted practice by EPA. Quarterly monitoring with an instrument and a leak definition of 500 ppm is assigned as a control effectiveness of 97%. Texas' LDAR program, 28LAER, provides for 97% control credit for valves, flanges, and connectors.

Remote sensing using infrared imaging has proven effective in identifying leaks, especially for components in difficult to monitor areas. LDAR programs and remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[6]

AVO monitoring is effective due to the frequency of observation opportunities, but it is not very effective for low leak rates. It is preferred for identifying large leaks of odorless gases such as methane; however, since pipeline natural gas is odorized with very small quantities of mercaptan, AVO observation is an effective method for identifying and correcting leaks in natural gas systems. Due to the pressure and other physical properties of plant fuel gas, AVO observations of potential fugitive leaks are likewise moderately effective.

The use of high quality components is also effective relative to the use of lower quality components.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Remote monitoring with an infrared instrument, while more costly than the generally accepted and used LDAR programs, is often more effective due to its mobility and ability to quickly scan many components in a short period of time. The use of leakless and sealless construction, and high quality material and components, while effective for longer term emissions control, are not considered justified due to the high cost and low potential to reduce emissions.

Step 5 – Selection of BACT

Enterprise proposes to implement the TCEQ 28LAER LDAR program for VOC/BACT/LAER purposes at the site, which is expected to effectively control process fugitive emissions. Though CO_2 is not detectable by the LDAR program, any steps taken to reduce methane fugitives will simultaneously reduce fugitive emissions of CO_2e at the site. Enterprise will also implement an AVO LDAR program for potential natural gas fugitive emissions.

H. Process Flare (FIN/EPN: FLARE2)

Process flares are necessary devices for the control of routine, maintenance, startup, and shutdown (MSS) emissions, and emergency VOC emissions from vents in a chemical process unit. The baseline flared stream consists of equipment and flare header sweeps. The compressor and pump housings proposed for the site are vented to the flare header providing control of VOCs and CO_2e. The flare header itself is purged with a constant stream of methane to prevent an explosive build up of oxygen and VOC that would present a danger to the operation of the

[6] 73 FR 78199-78219, December 22, 2008.

flare and the plant as a whole. The flare pilot flame is fired with methane and presents a source of GHG emissions.

Step 1 – Identification of Potential Control Technologies

- *Low Carbon Fuels* – The flare will use pipeline quality natural gas for the pilots and as supplemental fuel, if needed, to maintain appropriate vent stream heating value.
- *Good Combustion Practices, Design and Maintenance* - Good combustion practices include good design features for the process, appropriate maintenance of equipment and operation within the recommended heating value and flare tip velocity as specified by its design. Use of flow and composition monitors to accurately determine the optimum amount of natural gas required to maintain adequate VOC destruction in order to minimize natural gas combustion and the resulting CO_2 emissions.
- *Flaring Minimization* – Keep the duration and quantity of flaring to a minimum through good engineering design of the process and good operating practices.
- *Use of a thermal oxidizer in lieu of a flare* – Substitute a highly efficient VOC destruction device in place of the proposed plant flare.
- *Flare Gas Recovery* – Install a flare gas recovery system to capture VOC emissions from startup, shutdown, maintenance, and malfunction periods that would normally be vented to the proposed flare. This system would be used to compress and store vents streams and feed them back into the fuel gas stream during normal operations.

Step 2 – Elimination of Technically Infeasible Alternatives

A thermal oxidizer is not capable of handling sudden, large volumes of vapor coming to it from the process that could occur in the event of process malfunction. In addition, oxidizer would need to combust large amounts of methane to operate effectively. For the purposes of control of GHG emissions, a thermal oxidizer is not a technically feasible option.

All the other options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Proper operation and design of the flare, use of low carbon fuels and system controls to assure minimum heating values of the flare stream are maintained are effective in reducing the ongoing emissions of GHGs from the flare.

Flare minimization through good engineering process design and plant operation will also reduce the amount of potential GHGs released to the atmosphere.

Installation and maintenance of a flare gas recovery system could be expected to reduce annual GHG emissions by approximately 2,812 tons per year calculated on a CO_2e basis. This would amount to approximately 0.2% reduction in GHG emissions.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Good combustion design, use of low carbon fuels and flare minimization practices taken together will result in the most effective means to control emissions from the flare. Installation of a flare gas recovery system at the plant would result in environmental impacts due to the increased emissions of GHGs and other criteria pollutants caused by operation of compression systems not otherwise necessary at the plant. Enterprise represents that the flare gas recovery system would be idle 99% of the time and the cost of the systems is estimated to be about $179/ton GHG controlled, making it economically infeasible.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the flare:

- *Low Carbon Fuels* – The flare will combust pipeline natural gas in the pilots, and natural gas will be used as supplemental fuel, if needed, to maintain appropriate heating value in the flare stream.
- *Good Combustion Practices and Maintenance* – Good combustion practices include appropriate maintenance of equipment, flare tip maintenance, operating within the recommended heating value, and flare tip velocity as specified by its design. Flare system analyzers will be used to continuously monitor the combined heating value of the waste gas streams to determine the appropriate amount of natural gas that needs to be added to the stream is not excessive.
- *Proper process and equipment design* – Appropriate process and equipment design will reduce the amount of waste gas sent to the flare header during upsets.

Using these operating practices above will result in an emissions limit for the flare of 7,258 tpy CO_2e. Enterprise will demonstrate compliance with the CO_2 emission limit using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1, and the site specific fuel analysis for process fuel gas. The equation for estimating CO_2 emissions as specified in 40 CFR § 98.253(b)(1)(ii)(A) is as follows:

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) * 1.102311$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (short tons/year).
0.98 = Assumed combustion efficiency of the flare.
0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p = Measurement period index.
44 = Molecular weight of CO_2 (kg/kg-mole).
12 = Atomic weight of C (kg/kg-mole).
$(Flare)_p$ = Volume of flare gas combusted during the measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "$(MW)_p/MVC$" with "1".
$(MW)_p$ = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
MVC = Molar volume conversion factor (849.5 scf/kg-mole).
$(CC)_p$ = Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98 Subpart C, Table C-2, site specific analysis of process fuel gas, and the actual heat input (HHV).

I. Diesel Engines, Emergency Use (EPN: PM18.803 and PM 18.850C)

The plant will have two diesel engines used to power water pumps. One pump will be used to provide water to suppress any fires at the facility and another to provide raw water for use in an emergency. The company represents minor, recurring GHG emissions based on a scheduled operability testing of 52 hours per year. This amounts to a single one hour test run each week.

Step 1 – Identification of Potential Control Technologies for GHGs

Technologies capable of controlling GHG emissions from the engines include:

- *Use of low carbon fuel*
- *Good combustion practices and maintenance,* and
- *Limiting operation of the engines.*

Step 2 – Elimination of Technically Infeasible Alternatives

Use of low carbon fuels such as plant fuel gas or commercially available natural gas is not an option for these engines. Plant and natural gas supplies are may be interrupted in the emergency situations and, therefore, would not be able to provide the service for which they are intended.

Good combustion practices and limiting operation of the engines to test cycles, on a recurring basis, are both technically feasible to control routine GHG emissions from these sources.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Good combustion practices and limiting the operation of the engines are determined to be effective in limiting GHGs and, since they are both proposed as controls, do not need to be ranked in order of effectiveness.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Limiting the operation of the engines to weekly one hour test cycles and use in any emergency situations for which they are intended results in very limited emissions. Good combustion practices and regular maintenance will maximize efficient operation of the engines.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for each diesel engine:

- Good combustion practices and maintenance, and
- Limited operation of the engines to 52 hours per year, except when needed in emergency situations.

X. Endangered Species Act

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant and its consultant, Whitenton Group ("Whitenton"), and adopted by EPA.

A draft BA has identified nine (9) species listed as federally endangered or threatened in Chambers County, Texas:

Federally Listed Species for Chambers County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Reptiles	
Green sea turtle	*Chelonia mydas*
Hawksbill sea turtle	*Eretmochelys imbriacata*
Kemp's ridley sea turtle	*Lepidochelys kempii*
Leatherback sea turtle	*Dermochelys coriaea*
Loggerhead sea turtle	*Caretta caretta*
Birds	
Piper Plover	*Charadrius melodus*
Fish	
Smalltooth sawfish	*Pristis pectinata*
Mammals	
Louisiana black bear	*Ursus americanus luteolus*
Red Wolf	*Canis rufus*

EPA has determined that issuance of the proposed permit will have no effect on any of the nine listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

Because of EPA's "no effect" determination, no further consultation with the USFWS and NMFS is needed.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP

XI. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report prepared by Horizon Environmental Services, Inc. ("Horizon"), on behalf of Enterprise's consultant, Whitenton, submitted on January 27, 2014.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be location of the Dehydrogenation Unit Project. Horizon conducted a desktop review within a 1.0-mile radius area of potential effect (APE). The desktop review included an archaeological background and historical records review using the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). Based on the field survey, including shovel testing, no cultural resources were recorded at the location of proposed Dehydrogenation Unit. Based on the desktop review, no archaeological sites were identified within 1-mile of the APE.

EPA Region 6 determines that because no historic properties are located within the APE and that a potential for the location of archaeological resources within the construction footprint itself is low, issuance of the permit to Enterprise will not affect properties potentially eligible for listing on the National Register.

On January 21, 2014, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit.

EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XII. Environmental Justice (EJ)

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

XIII. Conclusion and Proposed Action

Based on the information supplied by Enterprise, our review of the analyses contained in the TCEQ NSR Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue Enterprise a PSD permit for GHG emissions for the proposed facility. We are also proposing PSD permit conditions to codify the representations made in the permit applications and the administrative record. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

APPENDIX

Annual Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month total basis, rolling monthly, shall not exceed the following:

Table 1. Annual Emission Limits

EPN	FIN	Description	GHG Mass Basis TPY[1]		TPY CO_2e[1,2]	BACT Requirements
HR15.101	HR15.101	Reactor Charge Heater	CO_2	280,394	281,558	BACT limit of 131.4 when burning recovered process fuel gas. Maintain 85% thermal efficiency of heater. See permit conditions III.A.3.a-u.
			CH_4	14.1		
			N_2O	2.82		
DW37.101	HR15.102	Regeneration Air Heater	CO_2	650,930	1,034,695[3]	See permit conditions III.A.2 and III.A.4.a-j.
			CH_4	23.9		
			N_2O	5.86		
	HR15.103	Waste Heat Boiler Combustion Unit (Duct Burners)	CO_2	19,540		See permit conditions III.A.2 and III.A.5.f-n.
			CH_4	0.98		
			N_2O	0.2		
	GT26.101A	Regeneration Air Compressor Gas Turbine A	CO_2	124,931		See permit conditions III.A.2 and III.A.6.a-j.
			CH_4	2.32		
			N_2O	0.23		
	GT26.101B	Regeneration Air Compressor Gas Turbine B	CO_2	124,931		See permit conditions III.A.2 and III.A. 6. a-j.
			CH_4	2.32		
			N_2O	0.23		
	BO10.101	Reactor Evacuation Ejector Effluent to Waste Heat Boiler	CO_2	111,627		Waste Heat Boiler - Meet BACT limit of no greater than 132 lb CO_2/MMBtu See permit condition III.2 a-f.
			CH_4	1.12		
			N_2O	0.09		
BO10.103A BO10.103B	BO10.103A BO10.103B	Auxiliary Boiler A and B	CO_2	16,335	16,405[4]	See permit condition III.A.7 a-s.
			CH_4	0.82		
			N_2O	0.16		
SK25.801	SK25.801 SK25.801MSS	Flare	CO_2	7,244	7,258	See permit condition III.A.8.a-e.
			CH_4	0.2		
			N_2O	0.03		

EPN	FIN	Description	GHG Mass Basis TPY[1]		TPY CO_2e[1,2]	BACT Requirements
FUG-PDH	FUG-PDH	Process Fugitive Emissions	CH_4	No Numerical Limit Established [5]	No Numerical Limit Established [5]	Implementation of TCEQ 28LAER/MID directed maintenance and inspection program. See permit condition III.A.9.
FUG-NGAS	FUG-NGAS	Natural Gas Fugitives	CH_4	No Numerical Limit Established [5]	No Numerical Limit Established [5]	Implement AVO LDAR. See permit condition III.A.9.
PM18.803	PM18.803	Fire Water Pump Engine	CO_2	16	16	Operation limited to 52 hours per year or during plant fire emergencies. See permit condition III.A.10 a-c, e-g.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
PM18.850C	PM18.850C	Raw Water Make Up Pump	CO_2	8	8	Use of Good Combustion Practices. Operation limited to 52 hours per year or during plant fire emergencies. See permit condition III.A.10 a-b, d -g
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
Totals[7]			**CO_2**	**1,338,692**	**CO_2e 1,342,659**	
			CH_4	**45.8**		
			N_2O	**9.47**		

1. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities
2. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298
3. This value is for the total emissions from the WHB stack (DW37.101) including the two combustion turbines (GT26.101A and GT26.101B), the regeneration air heater (HR10.102), the waste heat boiler combustion unit (HR10.103), and the coke burn and off-gassing from the catalyst regeneration process.
4. This value is for operation one of both Auxiliary Boilers and cannot be exceeded for both units combined.
5. Fugitive emission values are estimates based on work practices standards and not enforceable emission limits. Compliance with the emission limit will be determined by compliance with the work practice standard specified in the permit conditions. Fugitive potential to emit from process gas sources are estimated to be 0.25TPY of CH_4, equivalent to 6 TPY of CO_2e. Fugitive potential to emit from natural gas sources are estimated to be 13.04TPY of CH_4, equivalent to 326 TPY of CO_2e.
6. All values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
7. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.