Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for PL Propylene LLC

Permit Number: PSD-TX-18999-GHG

April 2013

This document serves as the statement of basis 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 February 7, 2012, PL Propylene LLC (PLP) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions to authorize a proposed modification at their Harris County facility, which is an existing minor stationary source. On July 24, 2012, PLP submitted an addendum to their application. In connection with the same proposed project, PLP submitted a minor new source review permit amendment application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on June 8, 2012. Under the terms of the permit sought from the TCEQ, the modification will not lead to increases in non-GHG pollutants that will exceed the significant emission rates at 40 CFR § 52.21(b)(23)(i). PLP proposes to construct six new combustion turbines, a charge gas heater, a regeneration air heater, a waste heat boiler, and a flare at the existing facility. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit that would authorize construction of air emission sources at the PLP facility.

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

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

II. Applicant

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Houston, TX 77017

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PL Propylene LLC
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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:
Aimee Wilson
Air Permitting Section (6PD-R)
(214) 665-7596

The Non-GHG PSD Permitting Authority for this permitting action is:

Air Permits Division (MC-163)
TCEQ
P.O. Box 13087
Austin, TX 78711-3087

IV. Facility Location

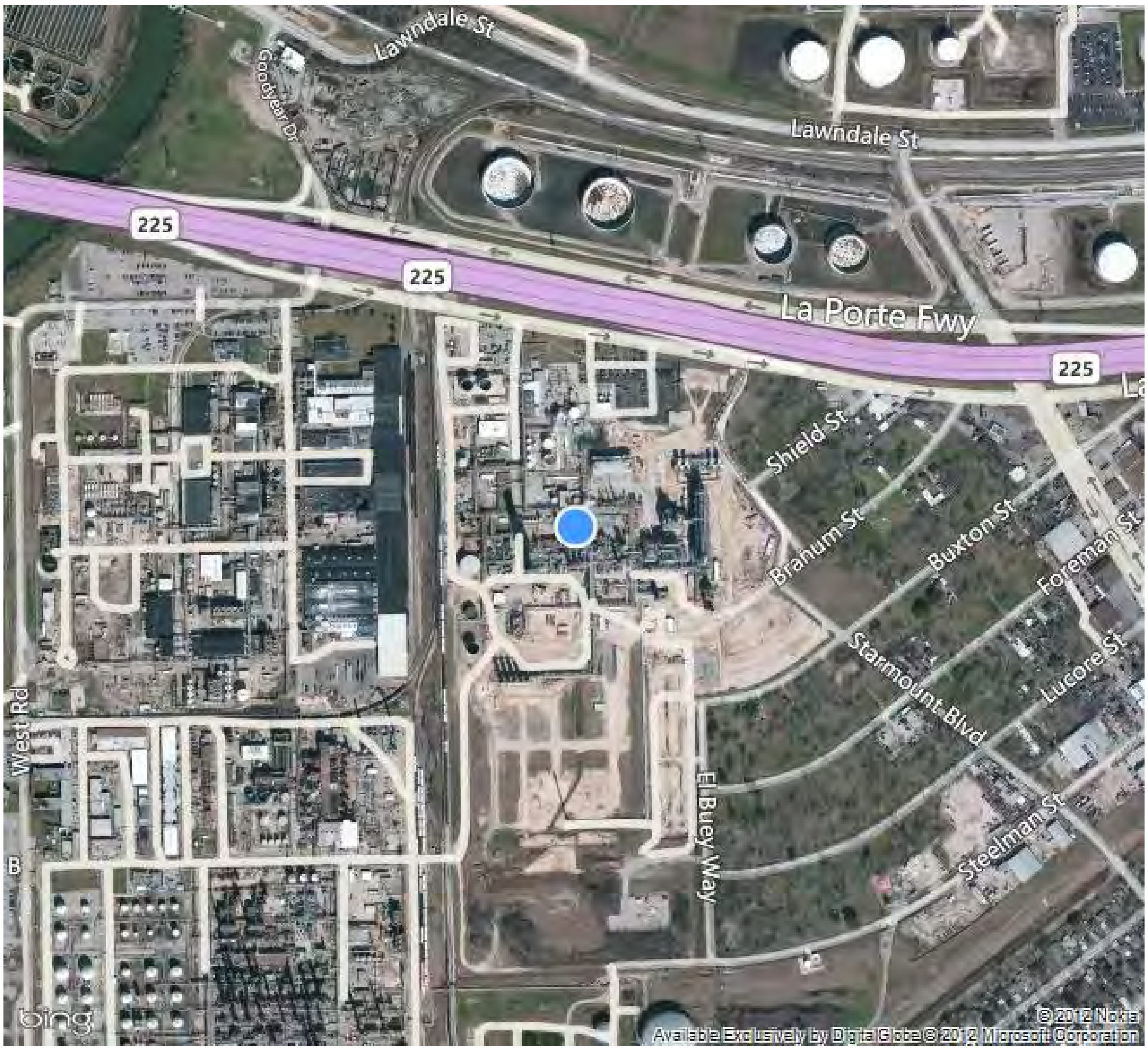
The PL Propylene facility is located in Harris County, Texas. The geographic coordinates for this facility are as follows:

Latitude: 29º 42’ 17” North
Longitude: - 95º 15’2” West

Harris County is currently designated severe nonattainment for ozone, and is currently designated attainment for all other pollutants. The nearest Class I area, at a distance of more than 500 kilometers, is Breton National Wildlife Refuge.

Below, Figure 1 illustrates the facility location for this draft permit.

Figure 1. PL Propylene Location



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

EPA concludes PL Propylene'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)(49)(v)(a). PLP is an existing PSD minor source for criteria pollutants and the proposed modification alone will exceed the PSD emission thresholds of 100,000 tons per year (tpy) CO2e and 100 tpy GHG mass basis. PLP calculates CO_2e emissions of 1,105,893 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.

The applicant represents that the proposed project is not a major stationary source for non-GHG pollutants. The applicant also represents that the increases in non-GHG pollutants will not be authorized (and/or have the potential) to exceed the "significant" emissions rates at 40 CFR § 52.21(b)(23). At this time, TCEQ, as the permitting authority for regulated NSR pollutants other than GHGs, has not issued the permit amendment for non-GHG pollutants; limits below the rates identified in (b)(23) must be in place prior to construction for this applicability analysis and for 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.

VI. Project Description

PL Propylene operates a propane dehydrogenation (PDH) facility. The plant utilizes the CATOFIN® propane dehydrogenation technology. PLP is able to produce either polymer grade propylene (PGP) or chemical grade propylene (CGP). The facility also produces commercial quantities of hydrogen as well as a C_4 mix hydrocarbon stream and a C_5+ mix hydrocarbon stream.

The PLP plant catalyst regeneration system currently consists of five gas generators (combustion units) and three electric blowers whose exhausts enter a joint or common manifold before passing through a direct-fired air heater to get the gas to sufficient temperature to regenerate the dehydration catalyst. The hot exhaust gases from the catalyst regeneration step then pass through a waste heat boiler (WHB2) which has supplemental fuel firing to generate steam before being vented to the atmosphere. The proposed modification will add six combustion turbines, a new charge gas heater, a regeneration air heater, a waste heat boiler, and a flare to the existing facility in Houston, Texas. The proposed modification will increase the production capacity of the plant by approximately 1.6 billion pounds per year of propylene (polymer and chemical grade).

Combustion Turbines (FIN- GT6, GT7, GT8, GT9, GT10, and GT11; EPN - WHB2)

The proprietary combustion turbines (GT6 through GT11) will burn natural gas and produce the hot exhaust gases needed to regenerate the catalyst in the dehydrogenation reactors. These combustion turbines will not be electric generating units. During normal operations, these units will vent to the regeneration air heater (RAH2) which in turn vents to the waste heat boiler (WHB2). These combustion turbines will vent to the atmosphere during periods of maintenance, startup, and shutdown (EPN- GT6MSS, GT7MSS, GT8MSS, GT9MSS, GT10MSS, and GT11MSS).

Regeneration Air Heater (FIN - RAH2; EPN - WHB2)

Exhaust gases from the combustion turbines (GT6, GT7, GT8, GT9, GT10, and GT11) pass through the regeneration air heater (RAH2) to achieve the necessary regeneration temperature. The heater is fired with natural gas and process fuel gas. The exhaust from the RAH2 will vent to the waste heat boiler (WHB2).

Waste Heat Boiler (WHB2)

The waste heat boiler (WHB2) receives exhaust gases from the regeneration air heater (RAH2) and the regeneration reactors in the propane dehydrogenation process. Supplemental heat from WHB2 is produced from the combustion of natural gas and process fuel gas for the production of steam. The combustion gases leaving the WHB will pass through a CATOX unit to control CO and VOC emissions and a selective catalytic reduction (SCR) to control NOx emissions. The WHB2 will be equipped with a CO_2 continuous emissions monitoring system (CEMS).

Charge Gas Heater (CGH2)

The propane feed to the dehydrogenation reactors first passes through a charge gas heater (CGH2) fired with a combination of natural gas and process fuel gas to increase the propane temperature to enable the dehydrogenation reaction to occur.

Flare (FLARE2)

A new process/emergency flare (FLARE2) will be added to safely combust process exhaust streams. The flare will be utilized for control of continuous and intermittent emissions associated with the manufacturing process.

Electrical Equipment Insulated with Sulfur Hexafluoride (SF6FUG)

The generator circuit breaker associated with the proposed unit will be insulated with Sulfur Hexafluoride (SF_6). SF_6 is a colorless, odorless, non-flammable, and non-toxic synthetic gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. The SF_6 capacity of the generator circuit breaker associated with the proposed unit will be approximately 72 lb. The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. The alarm will alert operating personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF_6 gas.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted in accordance with EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a "top-down" BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the most effective controls 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 contribute a small amount of GHGs. 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:

- Combustion Turbines (FIN: GT6, GT7, GT8, GT9, GT10, and GT11; EPN: WHB2)

- Regeneration Air Heater (FIN: RAH2; EPN:WHB2)
- Waste Heat Boiler (FIN/EPN: WHB2)
- Combustion Turbines Maintenance, Startup, and Shutdown (EPN: GT6MSS, GT7MSS, GT8MSS, GT9MSS, GT10MSS, and GT11MSS)
- Charge Gas Heater (FIN/EPN: RCH2)
- Flare (FIN/EPN: FLARE2)
- Fugitive Process Emissions (FIN/EPN: PLANT2)
- SF_6 Circuit Breaker (FIN/EPN: SF6-FUG)

IX. BACT Analyses

A. Post-Combustion Controls

For the proposed project, the Charge Gas Heater (RCH2) and the Waste Heat Boiler (WHB2) are capable of considering add-on (post combustion) control technologies that will recover CO_2 from gas streams emitted from combustion units. In lieu of considering 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 both emission unit types.

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)."[1] 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 oxyfuel 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, oxyfuel 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 oxyfuel combustion are not considered available control options for this proposed modification; the third approach, post-combustion capture, is applicable to the Charge Gas Heater, and the Waste Heat Boiler.

[1]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)

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.[2]

Step 2 – Elimination of Technically Infeasible Alternatives

The only available capture technology, post-combustion capture, is believed to be technically feasible for this project.[3]

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

PL Propylene developed a cost analysis for CCS that provided the basis for eliminating the technology in step 4 of the BACT analysis. EPA Region 6 reviewed PL Propylene's CCS 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 capture and compression facilities that would be required. The capital cost to construct a plant large enough to process the flue gases from the PLP facility is approximately $410 million. Amortized capital costs are expected to be $41 million based on a 20 year life for a post-combustion control system at 8% interests. Annual costs (operating costs plus amortized capital costs) are estimated to be approximately $81 million. The addition of CCS would increase the total capital project costs by more than 50%, which is excessive in relation to the overall cost of the proposed project. Thus, CCS has been eliminated as BACT for this project.

Economic infeasibility notwithstanding, PLP also asserts that CCS can be eliminated as BACT based on the environmental impacts from a collateral increase of National Ambient Air Quality

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[2] 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

[3] Based on the information provided by PL Propylene 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.

Standards (NAAQS) pollutants. Implementation of CCS would increase emissions of NOx, CO, VOC, PM_{10}, SO_2, and ammonia by as much as 13-17%[4]. The proposed plant is located in the Houston, Galveston, and Brazoria (HGB) area of ozone non-attainment and the generation of additional NOx and VOC could exacerbate ozone formation in the area. Since the project is located in an ozone non-attainment area, energy efficient technologies are preferred over add-on controls such as CCS that would cause an increase in emissions of NOx and VOCs to the HGB non-attainment area airshed. EPA has reviewed PLP's analysis and agrees that these other environmental factors resulting from the installation and operation of a CCS system further support the rejection of CCS as BACT for this proposed project.

Step 5 – Selection of BACT

See BACT analysis for the Charge Gas Heater (EPN: RCH2) and the Waste Heat Boiler (EPN: WHB2).

B. Combustion Turbines (FINs: GT6, GT7, GT8, GT9, GT10, and GT11, EPN:WHB2)

The combustion turbines are used to generate a sufficient quantity of hot air for the regeneration (decoking) of the dehydrogenation catalyst in the Catofin® reactors. These units are designed to operate at 1,000% excess air. These combustion turbines are a proprietary design and only produce heated air and do not generate electrical energy. Each unit is rated at 200 MMBtu/hr heat input (natural gas firing). These units vent to the Regeneration Air Heater (FIN: RAH2) during normal operations for control.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Combustion Unit Design* – PL Propylene selected an energy efficient proprietary design for its combustion turbines, to optimize heat, fuel, and overall energy efficiency. The units generate hot air in a one-step process as opposed to the traditional two-step process with a furnace and compressor. Thus, less energy is consumed per pound of product produced and less CO_2 is generated.
- *Periodic Tuning* – Good combustion practices include appropriate maintenance of equipment. As part of the maintenance activity, the combustors are tuned to restore highly efficient low-emission operation.
- *Reduction in Heat Loss* – To minimize heat loss from the combustion turbines and protect the personnel and equipment around the machine, insulation blankets are applied to the

[4] 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

combustion unit casing. The blankets minimize the heat loss through the combustion shell and help improve the overall efficiency of the machine.

- *Instrumentation and Controls* – Modern combustion units have sophisticated instrumentation and controls to automatically control the operation of the combustion unit. The control system monitors the operation of the unit and modulates the fuel flow and unit operation to achieve optimal high-efficiency low-emission performance for full-load and part-load conditions.

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

Since the combination of all of the control options in Step 1 are being proposed by the applicant, a ranking of the individual control options is not necessary.

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 are being proposed by the applicant, there is no need to evaluate the economic, energy and environmental impacts of the proposed project.

Step 5 – Selection of BACT

These combustion turbines are supplying heated air to the production process. For the purpose of comparing BACT limits, EPA has not been able to identify any previous GHG PSD permits that have comparable units. Combustion turbines previously permitted were for energy generation or compression purposes.

The following specific BACT practices are proposed for each gas generator (combustion unit):

- *Combustion Unit Design* - The combustion turbines will be designed to minimize heat loss.
- *Periodic Tuning* - The combustion turbines will have periodic maintenance and routine monitoring performed. Every 4,000 and 21,000 operating hours (base load) a detailed visual inspection will be conducted to check for external leakage, drain systems pluggage, air intake system, and exhaust unit.
- *Reduction in Heat Loss* - The combustion turbines will be equipped with waste heat recovery to produce propylene at an energy usage of 8,000 BTU/lb of product.

- *Instrumentation and Controls* - The combustion turbines will be equipped with a proprietary fuel gas and burner management system to monitor the combustion efficiency of the equipment.

BACT Limits and Compliance:

During normal operations, the combustion turbines (GT6, GT7, GT8, GT9, GT10, and GT11) will vent to the direct-fired regeneration air heater (RAH2), which in turn, will vent to the waste heat boiler (WHB2). Since the units vent to a common manifold or stack/vent at the waste heat boiler (WHB2), these units will have a combined BACT limit as discussed later in the Statement of Basis. These units combined (GT6, GT7, GT8, GT9, GT10, GT11, RAH2, and WHB2) will have a BACT limit of 117 lbs CO_2/MMBtu. The waste heat boiler (WHB2) is equipped with a CO_2 continuous emissions monitoring system (CEMS) to monitor for BACT compliance.

BACT for the combustion 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. Such efficient operation will minimize CO_2 formation in the combustion process. Each unit will have a proprietary fuel gas and burner management system to monitor the combustion efficiency of the equipment. The temperature is continuously measured across the burners. When the differential temperature across the burners exceeds 158 ^{o}F, an alarm is triggered and the cause of the alarm is investigated and resolved by operating personnel. This state-of-the-art design and other waste heat recovery operations produces propylene at an energy usage of 8,000 Btu/lb of product, whereas a traditional propylene production unit utilizing thermal cracking has a 12,000 Btu/lb production energy usage. Periodic preventative maintenance and routine monitoring of operating variables will assure that the units operate as designed. The manufacturer recommends that every 4,000 and 21,000 operating hours (base load) that a detailed visual inspection be conducted to check for external leakage, drain systems pluggage, air intake system pluggage, and exhaust unit fouling. Every 4,000 operating hours a general inspection will be conducted to check the burners and blades for hot spots, scoring, and damage. Every 21,000 operating hours a combustion and hot gas inspection will be conducted to check for hot pots, scoring, and damage.

C. Combustion Turbines MSS (FINs: GT6, GT7, GT8, GT9, GT10, and GT11; EPNs: GT6MSS, GT7MSS, GT8MSS, GT9MSS, GT10MSS, and GT11MSS)

The combustion turbines are used to generate a sufficient quantity of hot air for the regeneration (decoking) of the dehydrogenation catalyst in the Catofin® reactors. These units are designed to operate at 1,000% excess air. These combustion turbines are a proprietary design and only produce heated air and do not generate electrical energy. These units vent to the atmosphere during periods of maintenance, startup, and shutdown (MSS). The duration of atmospheric venting is short (a period of minutes). Each unit is rated at 200 MMBtu/hr heat input (natural gas firing).

Step 1 – Identification of Potential Control Technologies for GHGs

Please see Section IX.B. above.

Step 2 – Elimination of Technically Infeasible Alternatives

Please see Section IX.B. above.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Please see Section IX.B. above.

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

Please see Section IX.B. above.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for each gas generator (combustion unit) during MSS:

- *Combustion Unit Design* - The combustion turbines will be designed to achieve a BACT limit of 117 lb CO_2/MMBtu heat input when buring natural gas during MSS.

BACT Limits and Compliance:

PL Propylene 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).

PL Propylene will demonstrate compliance with the CO_2 emission limit established for the maintenance, startup, and shutdown (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:

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 §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 §98.33(a)(2)(ii).
EF = Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/MMBtu).
1×10^{-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 October 30, 2009 (74 FR 56395). Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month average, rolling monthly.

D. Regeneration Air Heater (FIN: RAH2; EPN: WHB2)

The Regeneration Air Heater (RAH2) takes the exhaust gases from the combustion turbines and heats these gases an additional 60^{o}F (approximate), boosting the gases to the temperature necessary for regenerating the catalyst in the Catofin® reactors. It is a direct-fired air heater equipped with a low NOx duct burner, with the combustion products mixing with the gas from the combustion units before going to the reactors. It is a forced draft heater and the exit temperature is continuously monitored. The heater can fire natural gas and process fuel gas. This unit vents to the Waste Heat Boiler (WHB2) for emission control.

Step 1 – Identification of Potential Control Technologies

- *Periodic Burner Tune-up* - The duct burners and heat recovery steam generators (HRSG) are tuned periodically to maintain optimal thermal efficiency.
- *Oxygen Trim Control* - Monitoring of oxygen concentration in the flue gas is conducted, and the inlet air flow is adjusted to maximize thermal efficiency.
- *Use of hydrogen as a Fuel* - 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. While the sale of hydrogen product is an integral part of the business model of the plant, hydrogen can be burned when it is not sold. Thus, it will be used to the maximum extent possible as a fuel in the burners of RAH2 in place of natural gas to reduce GHG emissions.

Step 2 – Elimination of Technically Infeasible Alternatives

Oxygen trim control for stand-alone heaters is not applicable to duct burners. Therefore, this option was eliminated on the basis of technical infeasibility. All remaining options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Substitution of hydrogen for natural gas (methane) results in 100% control of GHG emissions that would otherwise be emitted by each pound of methane replaced. However, while the GHG emission reduction effectiveness of substituting hydrogen is high, hydrogen is not always available if it is being sold so this reduces the effectiveness of this control option.

Periodic tune-ups of the duct burners is considered effective in reducing GHGs, although it is difficult to quantify the effectiveness. However, since the remaining control options, periodic burner tune-ups and use of hydrogen as a fuel, are being proposed by the applicant, a ranking of the individual control options is not necessary.

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

Since the remaining control options, periodic burner tune-ups and use of hydrogen as a fuel, are being proposed by the applicant, there is no need to evaluate the economic, energy and environmental impacts of the proposed project. However, it is important to note that the substitution of hydrogen may cause an increase in NOx 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	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Energy Transfer Company, Jackson County Gas Plant Ganado, TX	Gas Processing Plant	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT 1,102.5 lbs CO_2/MMSCF natural gas output for each plant. 1 plant contains: hot oil heater (48.5 MMBtu/hr); Trim Heater (17.4 MMBtu/hr); Molecular Sieve Regeneration Heater (9.7 MMBtu/hr); and TEG Dehydrator Unit Regeneration Gas Heater (3 MMBtu/hr).	2012	PSD-TX-1264-GHG
BASF FINA Petrochemicals LP, NAFTA Region Olefins Complex Port Arthur, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for steam package boilers - monitor and maintain a thermal efficiency of 77% 12-month rolling average basis	2012	PSD-TX-903-GHG
Enterprise Products Operating LLC, Eagleford Fractionation and DIB Units Mont Belvieu, TX	NGL Fractionation	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters (140 MMBtu/hr) BACT 85% thermal efficiency. Regenerant heaters (28.5 MMBtu/hr) BACT is good operating and maintenance practices.	2012	PSD-TX-1286-GHG

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Energy Transfer Partners, Lone Star NGL Mont Belvieu, TX	NGL Fractionation	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters (270 MBtu/hr) BACT limit 2,759 lb CO_2/bbl of NGL processed Regenerator Heaters (46 MMBtu/hr) BACT Limit 470 lbs CO_2/bbl of NGL processed.	2012	PSD-TX-93813-GHG

During normal operations, the combustion turbines (GT6, GT7, GT8, GT9, GT10, and GT11) will vent to the direct-fired regeneration air heater (RAH2), which in turn, will vent to the waste heat boiler (WHB2). Since the units vent to a common manifold or stack/vent at the waste heat boiler (WHB2), these units will have a combined BACT limit as discussed later in the Statement of Basis. These units combined (GT6, GT7, GT8, GT9, GT10, GT11, RAH2, and WHB2) will have a BACT limit of 117 lbs CO_2/MMBtu. The waste heat boiler (WHB2) is 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. These units combined will have a BACT limit of 117 lbs CO_2/MMBtu.

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 a firebox temperature of > 1,000 ^oF on a 12-month rolling average basis
- Maintain operation of the oxygen trim control.
- Calibrate and perform preventative maintenance on the fuel flow meters on an annual basis.
- Perform periodic tune-ups of boiler burners. Burners are visually inspected on an annual basis.
- Substitute produced hydrogen that is not sold as product for natural gas to the maximum extent possible in the heater or other existing combustion units at the site.

BACT for this heater consists of use of the latest technical designs and high efficiency 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. The regeneration air heater vents to the waste heat boiler for emission control. The heater is forced draft with continuous monitoring of the firebox temperature (> 1,000^{o}F). A system performance test after startup will determine the actual optimum operation temperature. 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. Fuel gas pressure to the heater will be monitored and maintained at <70 psig. An abrupt or gradual increase in fuel gas pressure is indicative of plugged burner tips which would cause improper combustion which will adversely affect the composition of the flue gas.

During normal operations, the combustion turbines (GT6, GT7, GT8, GT9, GT10, and GT11) will vent to the direct-fired regeneration air heater (RAH2), which in turn, will vent to the waste heat boiler (WHB2). Since the units vent to a common manifold or stack/vent at the waste heat boiler (WHB2), these units will have a combined BACT limit as discussed later in the Statement of Basis. These units combined (GT6, GT7, GT8, GT9, GT10, GT11, RAH2, and WHB2) will have a BACT limit of 117 lbs CO_2/MMBtu. The waste heat boiler (WHB2) is equipped with a CO_2 continuous emissions monitoring system (CEMS) to monitor for BACT compliance.

E. Waste Heat Boiler/ Duct Burner (FIN/EPN: WHB2)

Following the regeneration step (RAH2), the hot gases then pass through a Waste Heat Boiler (WHB2) to recover the heat from the gas stream and generate steam. The Waste Heat Boiler is equipped with a heat recovery steam generator (HRSG). 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 WHB2 pass through a catalytic oxidation (CATOX2) unit to control CO and VOC emissions and a selective catalytic reduction (SCR) unit to control NOx emissions. The boiler is an INDECK or equivalent design with duct burners. It is forced draft and the firebox temperature is continuously monitored.

Step 1 – Identification of Potential Control Technologies

- Periodic Burner Tune-up - The duct burners and heat recovery steam generators (HRSG) are tuned periodically to maintain optimal thermal efficiency.
- Oxygen Trim Control - Monitoring of oxygen concentration in the flue gas is conducted, and the inlet air flow is adjusted to maximize thermal efficiency.
- Economizer - Use of heat exchanger to recover heat from the exhaust gas to preheat incoming HRSG boiler feedwater to attain industry standard performance for thermal efficiency.
- HRSG Blowdown Heat Recovery - Use of a heat exchanger to recover heat from HRSG blowdown to preheat feedwater results in an increase in thermal efficiency.

- Condensate Recovery - Return of hot condensate for use as feedwater to the HRSG. Use of hot condensate as feedwater results in less heat required to produce steam in the HRSG, thus improving thermal efficiency.
- Use of hydrogen as a Fuel - 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 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

Oxygen trim control, while feasible for stand-alone boilers, is not applicable to duct burners in an HRSG using the combustion unit and regeneration air heater exhaust as the source of combustion air. Therefore, this option was eliminated on the basis of technical infeasibility. All remaining options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The installation of an economizer to preheat boiler feedwater and a heat exchanger to recover heat from the boiler blowdown are standard items on modern boiler. Therefore, these options are ranked first among the options in Step 1.

Substitution of hydrogen for natural gas (methane) results in 100% control of GHG emissions that would otherwise be emitted by each pound of methane replaced. However, while the GHG emission reduction effectiveness of substituting hydrogen is high, hydrogen is not always available if it is being sold so this reduces the effectiveness of this control option.

Periodic tune-ups of the duct burners is considered effective in reducing GHGs, although it is difficult to quantify the effectiveness.

The recovery of condensate for use as boiler feedwater is a known technique but often is expensive due to the layout of a plant's condensate system therefore it is ranked as one of the least effective of the options listed in Step 1.

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 remaining control options in Step 3 are being proposed by the applicant, there is no need to evaluate the economic, energy and environmental impacts of the proposed project. However, it is important to note that the substitution of hydrogen may cause an increase in NOx 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	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
BASF FINA Petrochemicals LP, NAFTA Region Olefins Complex Port Arthur, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for steam package boilers - monitor and maintain a thermal efficiency of 77% 12-month rolling average basis	2012	PSD-TX-903-GHG
Chevron Phillips Chemical Company, Cedar Bayou Plant Baytown, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for VHP boiler - monitor and maintain a thermal efficiency of 77% 12-month rolling average basis	2012	PSD-TX-748

During normal operations, the combustion turbines (GT6, GT7, GT8, GT9, GT10, and GT11) will vent to the direct-fired regeneration air heater (RAH2), which in turn, will vent to the waste heat boiler (WHB2). The waste heat boiler is equipped with a CO_2 continuous emissions monitoring system (CEMS). Compliance with the BACT limit will be based on the CO_2 emissions as measured by the CO_2 CEMS at WHB2. These units combined will have a BACT limit of 117 lbs CO_2/MMBtu. Use of these practices corresponds with a permit limit of 908,729 tpy CO_2e for the WHB2. Compliance with this limit will be determined by calculating the emissions on a monthly basis, and determining compliance with the BACT limit on a daily basis.

BACT for this heater will also 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 by maintaining it at the design efficiency factor of 117 lb CO_2/MMBtu heat input. 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. Fuel gas pressure to the heater will be monitored and maintained at <70 psig. An abrupt or gradual increase in fuel gas pressure is indicative of plugged burner tips which would cause improper combustion which will adversely affect the composition of the flue gas.

The following specific BACT practices are proposed for the waste heat boiler (WHB2):

- Maintain a CO_2 BACT limit of 117 lb CO_2/MMBtu heat input on a 365-day rolling average basis.
- 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 continuous emissions monitoring system (CEMS).
- 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.
- Substitute produced hydrogen that is not sold as product for natural gas to the maximum extent possible in the heater or other existing combustion units at the site.

F. Charge Gas Heater (FIN/EPN: RCH2)

The raw material propane and recycled propane are heated in the Charge Gas Heater (RCH2) prior to entering the Catofin® reactors. The combustion flue gases from the heater pass through a selective catalytic reduction (SCR) system for NOx 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.
- *Oxygen Trim Control* - Monitoring of oxygen concentration in the flue gas is conducted, and the inlet air flow is adjusted to maximize thermal efficiency.
- *Use of Hydrogen as a Fuel* - 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 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

Substitution of hydrogen for natural gas (methane) results in 100% control of GHG emissions that would otherwise be emitted by each pound of methane replaced. However, while the GHG emission reduction effectiveness of substituting hydrogen is high, hydrogen is not always available if it is being sold so this reduces the effectiveness of this control option.

Periodic tune-ups of the duct burners and oxygen trim control are both considered effective in reducing GHGs, although it is difficult to quantify their effectiveness. However, since the combination of all of the control options in Step 1 are being proposed by the applicant, a ranking of the individual control options is not necessary.

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 are being proposed by the applicant, there is no need to evaluate the economic, energy and environmental impacts of the proposed project. However, it is important to note that the substitution of hydrogen may cause an increase in NOx 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 in Step 5 of Section XI above, on pages 15 - 16.

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 continuous emissions monitoring system (CEMS).
- Maintain operation of the oxygen trim control.
- Calibrate and perform preventative maintenance on the fuel flow meters on an annual basis.
- Perform periodic tune-ups of boiler burners. Burners will be visually inspected on an annual basis.
- Substitute produced hydrogen that is not sold as product for natural gas to the maximum extent possible in the heater or other existing combustion units at the site.

BACT Limits and Compliance:

BACT for the charge gas heater will be a BACT limit of 117 lb CO_2/MMBtu heat input on a 365-day rolling average basis. PL Propylene shall install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

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 would be required to be kept to demonstrate compliance with the emission limits on a 12-month average, rolling 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 boiler and are considered a *de minimis* level in comparison to the CO_2 emissions.

G. Flare (FIN/EPN: FLARE2)

Process flares are necessary devices for the control of routine and emergency VOC emissions from vents in a chemical process unit. Since the process maximizes the recovery of flare gases, the baseline continuous flared stream consists of equipment and flare header sweeps. As such, the products of combustion contain CO_2. The flare stream also contains unburned CH_4 which is used as pilot gas to combust the VOCs.

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 and Maintenance* - Good combustion practices include appropriate maintenance of equipment and operating within the recommended heating value and flare tip velocity as specified by its design.

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

1. Low-Carbon Fuel and Good Combustion Practices
2. Low-Carbon Fuel
3. Good Combustion Practices

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

Low-Carbon Fuel

The use of low-carbon fuel is economically and environmentally practicable for the proposed project. Combustion of gaseous fuel in lieu of higher carbon-based fuels such as diesel or coal reduces emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing environmental benefits as well. Therefore, low-carbon fuel remains a viable control technology.

Good Combustion Practices

Good combustion practices effectively support the proper operation of the flare as a control and safety device. Therefore, good combustion practice also remains a viable control technology option.

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, natural gas will be used as supplemental fuel, if needed, to maintain combustion temperatures.
- *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.

Using these operating practices above will result in an emission limit for the flare of 8.51 tpy CO_2e. PL Propylene 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:

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).

H. Fugitive Process Emissions (FIN/EPN: PLANT2)

Emissions from piping components (valves and flanges) associated with this project consist of methane (CH_4) and carbon dioxide (CO_2). The majority of the GHG fugitives (greater than 99.8%) comes from methane. The CO_2e from fugitive emissions account for less than 0.01% of the project's total CO_2e emissions.

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.[5]

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 a very 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. High quality design is effective for longer term emission control, but often the higher cost of such components does not justify this practice.

Step 5 – Selection of BACT

[5] 73 FR 78199-78219, December 22, 2008.

PL Propylene proposes to conduct remote sensing on an annual basis coupled with daily AVO monitoring for leaks that can be seen or heard to detect methane leaking from the piping components in natural gas service for this project. Any component found to be leaking during remote sensing or AVO monitoring shall be repaired within 15 days. Though CO_2 is not detectable by remote sensing, any steps taken to reduce methane fugitives will simultaneously reduce emissions of CO_2 present in natural gas.

I. SF_6 Insulated Electrical Equipment (SF6-FUG)

The generator circuit breakers associated with the proposed units will be insulated with SF_6. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 72 lb of SF_6.

Step 1 – Identification of Potential Control Technologies for GHGs

In comparison to older SF_6 circuit breakers, modern circuit breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

One alternative considered in this analysis is to substitute another non-GHG substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NTIS) Technical note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure* SF_6.[6]

Step 2 – Elimination of Technically Infeasible Alternatives

According to the report NTIS Technical Note 1425, SF_6 is a superior dielectric gas for nearly all high voltage applications. It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6 insulated equipment. The report concluded that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture…it is clear that a significant amount of research must be

[6] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure* SF_6. NIST Technical Note 1425, Nov. 1997. Available at http://www.epa.gov/electricpower-sf6/documents/new_report_final.pdf

performed for any new gas or gas mixture to be used in electrical equipment". Therefore, there are currently no technically feasible options besides the use of SF_6.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The use of state-of-the-art SF_6 technology with leak detection to limit fugitive emissions is the highest ranked control technology that is feasible for this application.

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

Energy, environmental, or economic impacts are not addressed because the use of alternative, non-greenhouse gas substance for SF_6 as the dielectric material in the breakers is not technically feasible.

Step 5 – Selection of BACT

PL Propylene concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection as the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers.[7] The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will bring potential fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The lockout prevents any operation of the breaker due to the lack of "quenching and cooling" SF_6 gas.

PL Propylene will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmissions and Distribution Equipment Use.[8] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

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.

[7] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*.
[8] See 40 CFR Part 98 Subpart DD.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant, PL Propylene, LLC ("PL Propylene") and its consultant, Zephyr Environmental Corporation ("Zephyr") and adopted by the EPA.

A draft BA has identified eleven (11) species listed as federally endangered or threatened in Harris County, Texas:

Federally Listed Species for Harris 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**
Birds	
Red-cockaded Woodpecker Whooping Crane	*Picoides borealis* *Grus americana*
Amphibians	
Houston Toad	*Bufo houstonensis*
Fish	
Smalltooth Sawfish	*Pristis pectinata*
Mammals	
Louisiana Black Bear Red Wolf	*Ursus americanus luteolus* *Canis rufus*
Plant	
Texas Prairie Dawn Flower	*Hymenoxys texana*
Reptiles	
Green Sea Turtle Kemp's Ridley Sea Turtle Leatherback Sea Turtle Loggerhead Sea Turtle	*Chelonia mydas* *Lepidochelys kempii* *Dermochelys coriacea* *Caretta caretta*

EPA has determined that issuance of the proposed permit will have no effect on any of the eleven (11) 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.

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. Magnuson-Stevens Fishery Conservation and Management Act

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

To meet the requirements of the Magnuson-Stevens Act, EPA is relying on an EFH Assessment prepared by the applicant and reviewed and adopted by EPA.

The facility is adjacent to tidally influenced portions of the Sims Bayou Tidal which empties into Houston Ship Channel/Buffalo Bayou Tidal of the San Jacinto River Basin. These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, subadult or adult white shrimp (*Penaeus setiferus*) and brown shrimp (*Penaeus aztecus*). The EFH information was obtained from the NMFS's website (http://www.habitat.noaa.gov/protection/efh/efhmapper/index.html).

Based on the information provided in the EFH Assessment, EPA concludes that the proposed PSD permit allowing PL Propylene to construct an additional propylene production line and associated process equipment within the existing facility property will have no adverse impacts on listed marine and fish habitats, because there are no proposed direct construction impacts or indirect project impacts within the Houston Ship Channel/Buffalo Bayou Tidal. Further, air modeling indicates that pollutant levels will be below *de minimus* levels over the water. Finally, all wastewater and stormwater discharges that will be generated as a result of the project will be pretreated onsite resulting in negligible impacts on the water quality of the Sims Bayou Tidal.

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 essential fish habitat report can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XII. 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 reviewed and adopted a cultural resource report prepared by Horizon Environmental Services, Inc. ("Horizon") on behalf of Zephyr submitted on December 19, 2012.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 20 acres of land within and adjacent to the construction footprint of the existing facility. Horizon conducted a field survey of the property and a desktop review on the archaeological background and historical records within a 1-mile radius area of potential effect

(APE) which included a review of 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 results of the field survey, no archaeological resources or historic structures were found within the APE. Based on the cultural review, no cultural resource sites were identified within a 1-mile radius 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 is low within the construction footprint itself, issuance of the permit to PL Propylene will not affect properties on or potentially eligible for listing on the National Register.

On January 10, 2013, 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.

XIII. 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.

XIV. Conclusion and Proposed Action

Based on the information supplied by PL Propylene, 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 PL Propylene a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. 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 365-day rolling average basis, shall not exceed the following:

Table 1. Annual Emission Limits

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
GT6 GT7 GT8 GT9 GT10 GT11	WHB2	Combustion Turbines	CO_2	101,553[3]		Use of Good Combustion Practices. See permit conditions III.A.1. c. through h.
			CH_4	2[3]		
			N_2O	0.2[3]		
RAH2	WHB2	Regeneration Air Heater	CO_2	102,395	908,729[4]	Maintain firebox temperature ≥ 1,000 °F. See permit condition III.A.3.b.
			CH_4	2		
			N_2O	0.2		
WHB2	WHB2	Waste Heat Boiler/Duct Burners	CO_2	196,086		BACT limit of 117 lb CO_2/MMBtu heat input. See permit condition III.A.4.f.
			CH_4	3.7		
			N_2O	0.4		
GT6 GT7 GT8 GT9 GT10 GT11	GT6MSS GT7MSS GT8MSS GT9MSS GT10MSS GT11MSS	Combustion Turbines MSS	CO_2	842[3]	5,054[5]	BACT limit of 117 lb CO_2/MMBtu heat input. See permit condition III.A.2.d.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
RCH2	RCH2	Charge Gas Heater	CO_2	190,966	191,166	BACT limit of 117 lb CO_2/MMBtu heat input. See permit condition III.A.5.f.
			CH_4	3.6		
			N_2O	0.4		
FLARE2	FLARE2	Flare	CO_2	31	33	Use of Low Carbon Fuel and Good Combustion Practices. See permit condition III.A.6.
			CH_4	0.1		
			N_2O	No Numerical Limit Established[6]		
PLANT2	PLANT2	Fugitive Process Emissions	CH_4	No Numerical Limit Established[7]	No Numerical Limit Established[7]	Implementation of Remote Sensing/AVO program. See permit condition III.A.7.

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
SF6FUG	SF6FUG	SF_6 Fugitive Emissions	SF_6	No Numerical Limit Established[8]	No Numerical Limit Established[8]	Installation of low pressure alarm and low pressure lockout. See permit condition III.A.8.
Totals[9]			**CO_2**	**1,103,848**	**CO_2e 1,105,893**	
			CH_4	**63**		
			N_2O	**2**		

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 = 21, N_2O = 310
3. These values are for each individual gas generator combustion unit.
4. This value is for the total emissions from the WHB2 including the six combustion turbines (GT6, GT7, GT8, GT9, GT10, and GT11) and the regeneration air heater (RAH2).
5. This value is the combined allowable MSS emissions from all six combustion turbines (GT6, GT7, GT8, GT9, GT10, and GT11) combined.
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. Fugitive process emissions from EPN Plant2 are estimated to be 42 TPY of $CH_{4,}$ and 885 TPY CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
8. SF_6 fugitive emissions from EPN SF6FUG are estimated to be 0.00108 TPY of SF_6 and 26 TPY of CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
9. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.