Exhibit 7

Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for the ExxonMobil Chemical Company, Baytown Olefins Plant

Permit Number: PSD-TX-102982-GHG

May 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 May 22, 2012, the ExxonMobil Chemical Company (ExxonMobil) Baytown Olefins Plant (BOP) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a proposed construction project at an existing major stationary source of criteria pollutants. In connection with the same proposed project, ExxonMobil submitted a minor NSR permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on May 22, 2012. The project at the Baytown Olefins Plant proposes to construct a new ethylene production unit consisting of eight ethylene cracking furnaces and recovery equipment to produce polymer grade ethylene. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the ExxonMobil, Baytown Olefins Plant.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that ExxonMobil’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 ExxonMobil, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

ExxonMobil Chemical Company
Baytown Olefins Plant
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Baytown, TX 77522-4004

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III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 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

IV. Facility Location

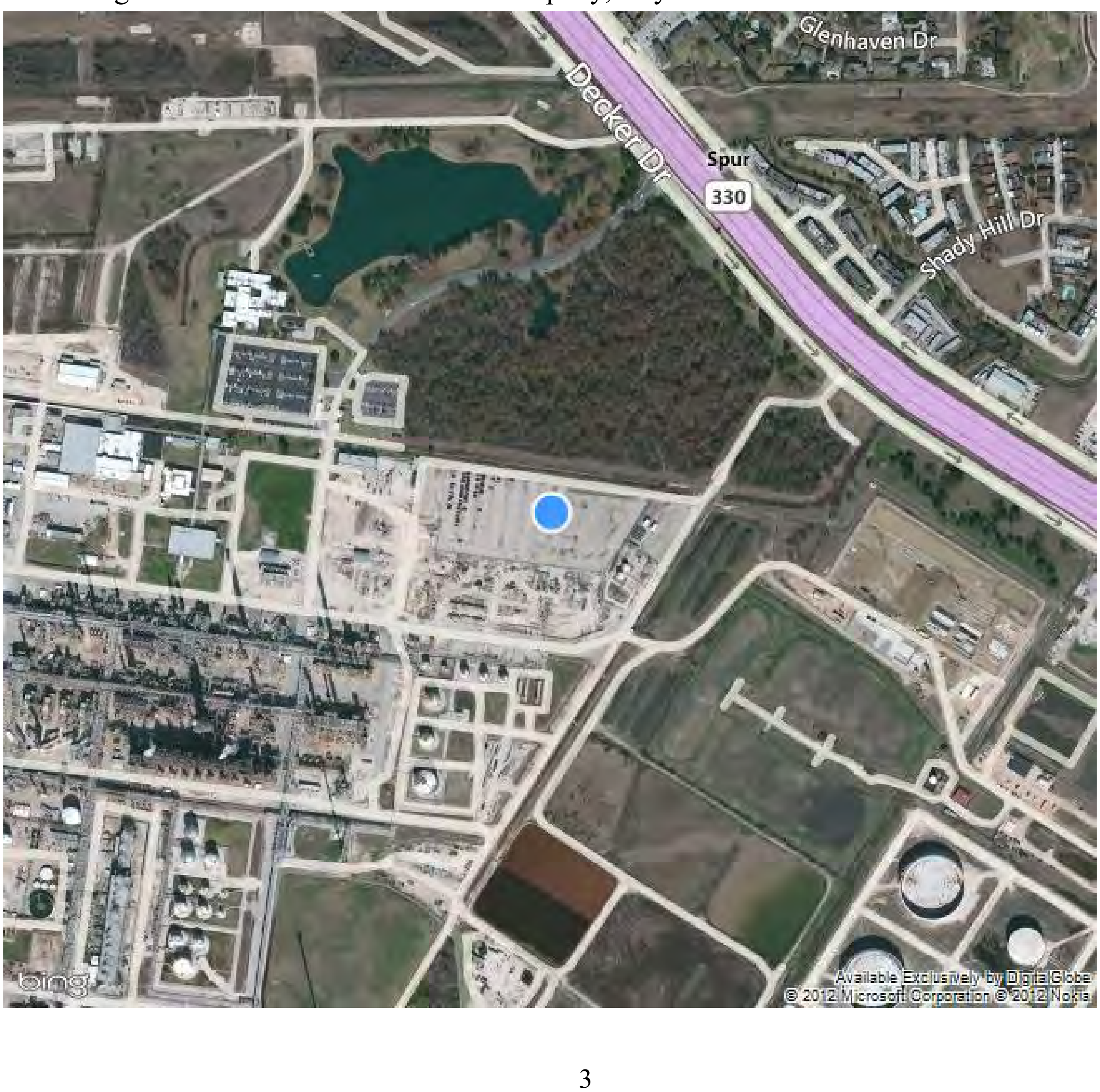
The ExxonMobil, Baytown Olefins Plant is located in Harris County, Texas. The geographic coordinates for this facility are as follows:

Latitude: 29º 49’ 29.58” North
Longitude: - 95º 0’24.22” 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 Caney Creek Wilderness Area.

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

Figure 1. ExxonMobil Chemical Company, Baytown Olefins Plant Location



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

EPA concludes ExxonMobil's application is subject to PSD review for the pollutant GHGs, because the project would lead to an emissions increase of GHGs for a facility in excess of the emission thresholds described at 40 CFR § 52.21(b)(49)(v). The facility is an existing major stationary source (as well as a source with a PTE that equals or exceeds 100,000 TPY CO2e and 100/250TPY GHGs mass basis), and the planned modification has a GHG emissions increase that equals or exceeds 75,000 TPY CO2e (and 0 TPY GHGs mass basis). ExxonMobil calculated a CO_2e emissions increase of 1,479,665 tpy for the proposed project.

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. EPA Region 6 considers the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases." As recommended in 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. Instead, EPA has determined that compliance with BACT is the best technique that can be employed at present to satisfy additional impacts analysis and Class I area requirements of the rules as they relate to GHGs. The applicant submitted an analysis to meet the requirements of 40 CFR § 52.21(o), as it may otherwise apply to the project. EPA's PSD permitting action will only authorize emissions of GHGs.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow ExxonMobil to construct a new ethylene production unit consisting of eight new steam cracking furnaces and recovery equipment at the existing olefins plant at the Baytown Olefins Plant (BOP) located in Baytown, Harris County, Texas. The major pieces of recovery equipment include a quench tower, caustic wash facilities, a process gas compressor and interstage coolers, a chiller train, a refrigeration system, a deethanizer, an ethylene/ethane (C_2) splitter, and a demethanizer. Bottoms product from the new deethanizer will serve as feed to the existing base plant depropanizer. In addition, a new cooling tower and a new flare system will be constructed. Existing utilities (such as plant air, electric, marginal steam product) will support the proposed project as needed. The modification increases the plant capacity, adding approximately 2 million metric tons per year of ethylene produced. The site will also have an increase in other products, including fuel gas, propylene, a heavy components (C3+) stream, and other lower-output hydrocarbon streams.

The ethylene production unit will operate by firing the furnace section, consisting of eight steam cracking furnaces (EPNs: XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST, and XXHF01-ST) continuously. The furnace design is proprietary and is equipped with ultra low NOx burners and Selective Catalytic Reduction (SCR) systems to control NOx emissions. The furnaces will crack fresh ethane that is combined with recycled ethane. Steam is introduced as part of the process. The furnace outlet stream is cooled in the Quench Tower.

A steam-educted stream from the wet air oxidation unit, along with various other streams (process off gas) with a low hydrocarbon concentration, will be routed to the steam cracking furnaces for safety and/or to provide for control of volatile organic compounds (VOC). The process off gas stream is composed of mainly steam, nitrogen, and a small amount of hydrocarbons. The streams routed to the fire boxes of the proposed cracking furnaces are expected to account for less than 0.4% of the carbon entering the furnaces on an annual basis, and will contribute less than 0.01% to the annual GHG mass basis tpy emissions.

The furnaces will fire imported natural gas or a blended fuel gas that consists of imported natural gas and tail gas. The tail gas is a recycle stream resulting from an initial separation of methane and hydrogen during the chilling step within the demethanizer system. The composition of blended fuel gas will vary and will depend on current hydrogen production and disposition.

In the cracking operation, coke (molecular carbon) gradually builds on the inside walls of the furnace tubes. This layer of coke impedes heat transfer and must be removed while the furnace is offline through a steam/air decoke operation, which is expected to occur approximately every 30 days. The coke is removed from the walls of the furnace tubes through oxidation and spalling. The spalled coke fines are disengaged from the furnace effluent in the decoke drum. Particulate matter emissions are controlled through cyclonic separators at the decoke drum vent which releases to atmosphere (EPNs: XXAB-DEC, XXCD-DEC, XXEF-DEC, and XXGH-DEC).

The combined furnace effluent will flow into the Quench Tower where it is cooled with quench water. The majority of the dilution steam and some of the heavier hydrocarbons are condensed and exit the tower bottoms.

The deethanizer will separate the hydrocarbons with two or less carbon atoms from heavier hydrocarbons. The overhead stream from this process will be sent to the Acetylene Converters where acetylene is converted to ethylene and ethane. The Deethanizer bottoms product, hydrocarbons with more than 2 carbon atoms, is sent to the Depropanizer in the existing plant facilities.

A new cooling tower (EPN: BOPXXCT) will be constructed to provide process heat removal and supply cooling water to the proposed project. This cooling tower will be a multi-cell, induced draft, counter-flow type cooling tower. No GHG emissions will be emitted by the cooling tower.

A new flare system (EPNs: FLAREXX1 and FLAREXX2) will be designed to provide safe control of gases vented from the proposed project. This system will be equipped with a totalizing flow meter and an on-line analyzer to speciate the hydrocarbons in the flare gases, including Highly Reactive Volatile Organic Compounds (HRVOCs).

The proposed project includes up to five backup generators, total power output will not exceed three megawatts total. Each unit is powered by a diesel engine (EPNs: DIESELXX01, DIESELXX02, DIESELXX03, DIESELXX04, and DIESELXX05) and there will be one diesel storage tank associated with each backup generator installed. The normal operation of the generators is to test for proper operation weekly.

The proposed project will provide two booster pumps for the existing firewater system. These pumps will each be powered by a diesel engine (EPNs: DIESELXXFW1 and DIESELXXFW2). The normal operation of the booster pumps and engines is to test for proper operation weekly.

Duct burners will be added to the existing heat recovery steam generator (HRSG) section of the gas turbine generator train 5 (Train 5) to provide supplemental heat to the turbine exhaust stream, thereby generating supplemental steam for use at the Baytown Olefins Plant. Train 5 (HRSG05) is located at the Baytown Olefins Plant's base plant and is equipped with a Selective Catalytic Reduction (SCR) unit for NOx emission control. The HRSG section's function is to generate steam by recovering heat contained in the exhaust gas stream of the gas turbine generator. The purpose of the duct burners is to generate incremental steam during times when the steam cracking furnaces are unable to meet the steam demand. The duct burners are configured in rows and will be fired at their design firing rate to create additional steam from natural gas firing. There will be no increase in the firing of the gas turbine generator section of Train 5 due to the installation of the duct burners.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit considered the recommendations in 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 and BACT Discussion

The majority of the contribution of GHGs associated with the project is from combustion sources (i.e., cracking furnaces, furnace decoking, duct burners flare, and emergency engine testing). The site has some fugitive emissions from piping components which contribute an insignificant amount of GHGs. These stationary combustion sources 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:

- Steam Cracking Furnaces (EPNs: XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST, and XXHF01-ST)
- Decoke Drum Vents (EPNs: XXAB-DEC, XXCD-DEC, XXEF-DEC, and XXGH-DEC)
- Train 5 Duct Burners (EPN: HRSG05)
- Flare System (EPNs: FLAREXX1 and FLAREXX2)
- Engines (EPNs: DIESELXX01, DIESELXX02, DIESELXX03, DIESELXX04, DIESELXX05, DIESELXXFW1, and DIESELXXFW2)
- Equipment Fugitives (EPN: BOPXXAREA)

IX. Steam Cracking Furnaces (EPNs: XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST, and XXHF01-ST)

The ethylene unit consists of eight proprietary steam cracking furnaces (XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST, and XXHF01-ST). The furnaces are equipped with low NOx burners and selective catalytic reduction (SCR) systems to control NOx emissions. Furnace fuel is natural gas or a blended fuel gas that consists of natural gas and tail gas from the demethanizer system.

Various streams with very low hydrocarbon concentrations will be routed to the steam cracking furnaces for safety and/or to provide control of volatile organic compounds (VOC). The streams routed to the fireboxes of the steam cracking furnaces are expected to account for less than 0.4% of the carbon entering the furnaces on an annual basis, and will contribute less than 0.01% to the annual GHG mass basis tpy emissions. These streams are not considered a fuel source for the cracking furnaces. These are two phase streams that do not lend themselves to accurate measurements via on-line flow meters, analyzers, or even grab samples. The emissions from the control of these vent streams will be estimated using company records as defined in 40 CFR § 98.6, and the high heating value (HHV) and emission factors will be taken from 40 CFR Part 98, Subpart C, Tables C-1 and C-2. Equations C-1 and C-8 as defined in 40 CFR Subpart C will be used for the calculation. These emissions are included in the total GHG mass emissions from the cracking furnaces.

As part of the PSD review, ExxonMobil provides in the GHG permit application a 5-step top-down BACT analysis for the eight steam cracking furnaces. EPA has reviewed ExxonMobil's BACT analysis for the furnaces, which has been incorporated into this Statement of Basis, and also provides its own analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Carbon Capture and Storage* – CCS is an available add-on control technology that is applicable for all of the site's affected combustion units.
- *Energy Efficient Design* – ExxonMobil selected an energy efficient proprietary design for its steam cracking furnaces. To maximize thermal efficiency at BOP, the steam cracking furnaces will be equipped with heat recovery systems to produce steam from waste heat for use throughout the plant.
- *Low Carbon Fuels* – Use of fuels containing lower concentrations of carbon generate less CO_2 than other higher-carbon fuels. Typically, gaseous fuels such as natural gas or high-hydrogen plant tail gas contain less carbon, and thus lower CO_2 potential, than liquid or solid fuels such as diesel or coal. ExxonMobil proposes to use natural gas or a blended fuel gas that consists of natural gas and tail gas.
- *Good Operating and Maintenance Practices* – Good combustion practices include appropriate maintenance of equipment and operating within the recommended combustion air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control.

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). Accordingly, pre-combustion capture and oxyfuel combustion are

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

not considered available control options for this proposed facility; the third approach, post-combustion capture, is applicable to the steam cracking furnaces.
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

All options identified in Step 1 are considered technically feasible for this project.[3]

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- CO_2 capture and storage (up to 90%)
- Low-Carbon Fuel (approximately 40%)
- Energy Efficient Design
- Good Operating and Maintenance Practices

CO_2 capture and storage is capable of achieving 90% reduction of produced CO_2 emissions and thus considered to be the most effective control method. CCS is technically feasible. Use of low-carbon fuel, energy efficient design, and good combustion practices are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. These technologies all may be used concurrently (including, at least in theory, in conjunction with CCS). The estimated efficiencies were obtained from Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008). This report addressed improvements to existing energy systems as well as efficiencies associated with new equipment.

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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 ExxonMobil 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 technologically feasible at this source.

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

ExxonMobil developed a cost analysis for CCS that provided the basis for eliminating the technology in step 4 of the BACT process as a viable control option based on economic costs. The majority of the cost for CCS was attributed to the capture and compression facilities that would be required. The total annual cost of CCS capital and operating expenses would be $205,000,000 per year, including the cost of transport. The addition of CCS would increase the total capital project costs by more than 25%. EPA Region 6 reviewed ExxonMobil's CCS cost estimate and believes it adequately approximates the cost of a CCS control for this project and demonstrates those costs are prohibitive in relation to the overall cost of the proposed project. Thus, CCS has been eliminated as BACT for this project.

Economic infeasibility notwithstanding, ExxonMobil also asserts that CCS can be eliminated as BACT based on the energy and environmental impacts from a collateral increase of criteria pollutants (i.e. those pollutants for which EPA has promulgated primary and secondary National Ambient Air Quality Standards). Implementation of CCS would increase emissions of NOx, CO, VOC, PM_{10}, and SO_2 by as much as 11% from the additional utilities and energy consumption demands that would be required to operate the CCS system. The increase in criteria pollutants would be greater if looking at the emissions from the other support equipment that would be needed to further treat and compress the CO_2 emissions sufficiently to transport it to an appropriate sequestration location. 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.

Low-Carbon Fuel

The use of low-carbon fuel is economically and environmentally practicable for the proposed project. Use of blended fuel gas, because of its rich hydrogen content (average of 74 mol%), contains less carbon than natural gas.

Energy Efficient Design

The use of an energy efficient furnace and unit design is economically and environmentally practicable for the proposed project. By optimizing energy efficiency, the project requires less fuel than comparable less-efficient operations, resulting in cost savings. Further, reduction in fuel consumption corresponding to energy efficient design reduces emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing environmental benefits as well. Specific technologies utilized by the furnaces include the following:

- Economizer - Use of heat exchanger to recover heat from the exhaust gas to preheat incoming Steam Drum feedwater to attain thermal efficiency.
- Steam Generation from Process Waste Heat - Use of heat exchangers to recover heat from the process effluent to generate high pressure steam. The high pressure steam is then superheated by heat exchange with the furnace exhaust gas, thus improving thermal efficiency.
- Feed Preheat - Use of heat exchangers to increase the incoming temperature of the feed, thereby reducing furnace firing demand.
- Minimize Steam to Hydrocarbon Ratio - Minimizing steam to hydrocarbon ratio reduces the furnace firing.

Good Operating and Maintenance Practices

Good operation and maintenance practices for the steam cracking furnaces extend the performance of the combustion equipment, which reduces fuel gas usage and subsequent GHG emissions. Operating and maintenance practices have a significant impact on performance, including its efficiency, reliability, and operating costs.

Examples of good operating and maintenance practices include good air/fuel mixing in the combustion zone; sufficient residence time to complete combustion; proper fuel gas supply system operation in order to minimize fluctuations in fuel gas quality; good burner maintenance and operation; and overall excess oxygen levels high enough to safely complete combustion while maximizing thermal efficiency.

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 furnace limit flue gas exhaust temperature ≤ 309 °F. 365-day average, rolling daily	2012	PSD-TX-903-GHG

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Williams Olefins LLC, Geismar Ethylene Plant Geismar, LA	Ethylene Production	Energy Efficiency/Low-emitting Feedstocks/Lower-Carbon Fuels	Cracking heaters to meet a thermal efficiency of 92.5% Ethane/Propane to be used as feedstock Fuel gas containing 25% volume hydrogen on an annual basis	2012	PSD-LA-759
INEOS Olefins & Polymers U.S.A., Chocolate Bayou Plant Alvin, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for furnace limit flue gas exhaust temperature ≤ 340 ^oF. Fuel will have ≤ 0.71 lbs carbon per lb of fuel (CC); 0.85 lbs GHG/lbs of ethylene. 365-day total, rolled daily.	2012	PSD-TX-97769-GHG
Chevron Phillips Chemical Company, Cedar Bayou Plant Baytown, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for furnace limit flue gas exhaust temperature ≤ 350 ^oF. 12-month rolling average basis	2013	PSD-TX-748-GHG

BASF and Williams have differing processes for producing ethylene. BASF is a steam driven operation using multiple feedstocks, whereas Williams is utilizing electrical driven compressors and only ethane/propane as a feedstock which will require less energy consumption. This makes the Williams process more efficient than BASF. Since INEOS is only utilizing ethane gas as a feed, it can be compared to the Williams Olefins unit and has comparable furnace efficiency. The Williams Olefins unit has much smaller ethylene crackers than INEOS and utilizes electric power for their compressors in the downstream units. The ExxonMobil furnaces will be equipped with duct burners/heat recovery steam generators (HRSGs) and will have an exhaust temperature of 340^{o}F or less during ethylene production. This value is within the range permitted at similar facilities. The minimum estimated furnace efficiency, for ExxonMobil's furnaces, during on-line operation is 92% based on a 2% casing heat loss and 340°F maximum stack temperature. This is approximately the same thermal efficiency as the Williams Olefins furnaces.

The following specific BACT practices are proposed for each furnace:

- *Energy Efficient Design* - Continuously monitor the steam cracking furnaces' exhaust stack temperature and control to a maximum stack exit temperature of 340°F on a 365-day rolling average basis, not including periods of startup, shutdown, and decoking.
- *Low Carbon Fuels* – Pipeline quality natural gas and a blended fuel gas will be utilized.
- *Good Operating and Maintenance Practices* – The use of good combustion practices includes periodic combustion tune-ups and maintaining the recommended combustion air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control.

BACT Limits and Compliance:

By implementing the operational measures above will equate to an emission limit for the furnaces of 987,968 tpy CO_2e. In addition to meeting the quantified emission limit, EPA is proposing that ExxonMobil will demonstrate compliance with energy efficient operations by continuously monitoring the exhaust stack temperature of each furnace. The maximum stack exit temperature of 340°F on a 365-day, rolling average basis will be calculated daily for each furnace.

ExxonMobil will demonstrate compliance with the CO_2e emission limit for the furnaces using the site specific fuel analysis for blended fuel gas utilizing an on-line gas composition analyzer and the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

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

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (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).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at § 98.33(a)(2)(ii).

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

The proposed permit also includes an alternative compliance demonstration method, in which ExxonMobil may 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, Subpart C, Table C-2, site specific analysis of blended fuel gas, and the actual heat input (HHV). However, the emission limit is for all GHG emissions from the furnace, and is met by aggregating total emissions. 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 CO_2e emission limit on a 12-month average, rolling monthly.

An initial stack test demonstration will be required for CO_2 emissions from at least four of the eight emission units to verify that the CO_2e limit will be met. The stack test will also monitor the exhaust stack temperature to ensure compliance with the BACT limit of $340^{\circ}F$ on a 365-day rolling average. 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 furnaces and are considered a *de minimis* level in comparison to the CO_2 emissions.

X. Decoking Activities (EPNs: XXAB-DEC, XXCD-DEC, XXEF-DEC, and XXGH-DEC)

The proposed steam cracking furnaces will require periodic decoking to remove coke deposits from the furnace tubes. Coke buildup is inherent in olefin productions. Removal of coke at optimal periods maintains the furnace at efficient ethane-to-ethylene conversion rates without increasing energy (fuel) demand. Decoking too early is unnecessary and results in excess shutdown/start-up cycles. Decoking too late results in fouled furnace tubes that reduce conversion rates and increases heat demand. The GHG emissions consist of CO_2 that is produced from combustion of the coke build up on the coils. GHG emissions from this operation are very low, less than 0.15% of the GHG emissions attributable to the project.

Step 1 – Identification of Potential Control Technologies

There are two known ways to minimize CO_2 generated from decoking operations:

- Limiting air/steam during the decoking process and
- Minimizing the amount of coke formed in the furnace through proper design and operation of the furnace.

There are no additional available add-on technologies identified in the RACT/BACT/LAER Clearinghouse (RBLC) that have been applied to furnace decoking operations to control CO_2 emissions once generated.

Step 2 – Elimination of Technically Infeasible Alternatives

Limiting air and/or steam and proper furnace design and operation to minimize coke formation are both considered technically feasible for the steam cracking furnaces.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Both options identified for controlling GHG emissions from decoking operations are considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, a ranking is not possible.

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

Limiting air and/or steam would reduce CO_2, but it would increase CO emissions from the process by driving the conversion of coke to CO rather than CO_2. Limiting air could also result in an incomplete decoke, which would lead to an increase in the frequency of decoke events. Because coke buildup acts as an insulator, its presence decreases the efficiency of the furnace, resulting in an increase in CO_2.

As noted above, coke formation is inherent to the design and operation of a steam cracking furnace. Decoking is performed once metallurgical or hydraulic limits are reached. The furnace coking rate will be minimized through design, control, and operations. The design will ensure good feed quality, conversion control, and heat distribution. Minimizing coke buildup is the key factor to reduce CO_2 emissions.

Step 5 – Selection of BACT

ExxonMobil proposes to incorporate a combination of design and recommended operation to limit coke formation in the tubes to the extent practicable considering ethane as a raw material. The steam cracking furnaces will be decoked approximately every 30 days. Timing and frequency of decokes depends on several factors including furnace tube pressure drop, furnace tube temperature, and safety considerations (e.g., force majeure or equipment malfunctions). These factors are monitored by operations personnel and/or by electronic means. Estimated CO_2 emissions from decoke operations is negligible compared to annual total from the furnaces. Managing coke buildup through such methods will result in limited CO_2 formation from periodic decoking operations.

XI. Train 5 Duct Burners (EPN: HRSG05)

The purpose of the duct burners is to generate incremental steam during times when the steam cracking furnaces are unable to meet the steam demand. The duct burners are configured in rows and will be fired at their design firing rate to create additional steam from natural gas firing. The duct burners will emit GHGs; 99% of the CO_2e emissions are CO_2.

Step 1 – Identification of Potential Control Technologies

- *Carbon Capture and Storage (CCS)* – CCS is an available add-on control technology that is applicable for all of the sites affected combustion units.
- *Use of Low Carbon Fuel* – Fuels containing lower concentrations of carbon generate less CO_2 emissions than higher carbon fuels.
- *Use of Good Operating and Maintenance Practices* –
  - *Periodic Visual Inspections*- The burner tips are visually inspected on an annual basis and cleaned when needed.
  - *Maintain Complete Combustion* - CO concentrations are continuously monitored by an on-line analyzer to ensure complete combustion.
  - *Oxygen Trim Control* - Monitoring of oxygen concentration in the flue gas is conducted, and the inlet air flow is adjusted to maximize thermal efficiency.
- *Energy Efficient Design* –
  - *Use of an Economizer* - Use of a heat exchanger to recover heat from the exhaust gas to preheat incoming HRSG Section boiler feedwater to attain thermal efficiency.
  - *HRSG Section Blowdown Heat Recovery* - Use of a heat exchanger to recover heat from HRSG Section blowdown to preheat feedwater results in less heat required to produce steam in the HRSG, thus improving thermal efficiency.

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

<u>Carbon Capture and Storage</u>

This add-on control technology was already discussed in detail in section IX. Based on the economic infeasibility and negative energy and environmental issues discussed in section IX above, CCS will not be considered further in this analysis.

Step 2 – Elimination of Technically Infeasible Alternatives

Use of a low carbon fuel is technically feasible. Pipeline quality natural gas is the lowest carbon fuel commercially available at the BOP. ExxonMobil does utilize a blended fuel gas in the furnaces. There is only enough blended fuel gas for use in the furnaces.

Oxygen trim control, feasible for stand-alone boilers, is not applicable to duct burners in Train 5 since gas turbine exhaust streams are the source of combustion air. Therefore, this option is eliminated on the basis of technical infeasibility.

All remaining options identified in Step 1 are considered technically feasible. An economizer, condensate return, blowdown heat recovery, and CO analyzer are already in use on the existing HRSG Section and will continue to be used; therefore, these alternatives are not addressed in Steps 3 and 4 of the analysis.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Natural gas is among the lowest-carbon fuels commercially available and is the only commercially available fuel source at the BOP. As stated earlier, blended fuel gas is available, but not in a large enough quantity.

The remaining technology not already included in the existing HRSG configuration is periodic inspection of the burners. The energy efficiency improvement of burner inspections cannot be directly quantified.

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 natural gas 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.

Periodic Visual Inspections

Performing regular visual inspections of the burners can ensure proper operation of the duct burners which can have a positive effect on their operation ensuring proper combustion, although the effectiveness cannot be directly quantified. There are no significant adverse energy or environmental impacts associated with this control option.

Step 5 – Selection of BACT

To date, other facilities with a similar source given 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 gas turbine auxiliary duct burners - monitor and maintain a thermal efficiency of 60% 12-month rolling average basis	2012	PSD-TX-903-GHG

ExxonMobil proposes to maintain a minimum thermal efficiency of 70%. This limit is based on historical operational data of Train 5 and includes projected performance with the duct burners. This value is 10% higher than the thermal efficiency limit granted to a similar emission source as shown in the table above.

The following specific BACT practices are proposed for the duct burners to assure this level of thermal efficiency:

- *Low Carbon Fuels* – Consume pipeline quality natural gas, or a fuel with a lower carbon content than natural gas, as a fuel to the duct burners.

- *Good Operating and Maintenance Practices –*
    - *Perform and maintain records of online burner visual inspections annually and perform cleanings of the duct burner tips during planned shutdowns or as-needed, whichever comes first, to maintain thermal efficiency.*
    - *Calibrate and perform preventative maintenance checks on the duct burners' fuel flow meters annually.*
- *Energy Efficient Design*
    - *Maintain operation of the existing condensate recovery, HRSG Section blowdown heat recovery, and economizer as necessary to achieve an overall 70% thermal efficiency on a 12-month rolling average.*
    - *Demonstrate operational BACT for the duct burners by calculating the thermal efficiency of no less than 70% on a 12-month rolling average basis. Efficiency will be demonstrated by the following equation:*

$$Unit\ Efficiency\ = \frac{\begin{array}{c}Heat\ Content\ of\ Steam\ Produced + \\ Heat\ Content\ of\ Power\ Produced\end{array}}{Heat\ Content\ of\ Fuel\ Supply} \times 100\%$$

- CO_2e emissions from the duct burners will be determined based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance.
- Determine 12-month rolling average firing rates of the duct burners and recorded monthly.

BACT Limits and Compliance:

Using the operating practices above will result in an emission limit for the duct burners of 397,709 tpy CO_2e. ExxonMobil will demonstrate compliance with the CO_2e emission limit using the emission factors for natural gas from 40 CFR Part 98, Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

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

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (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).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).

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

The GHG mass emission limits in TPY associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2, using the GWPs as published on October 30, 2009 (74 FR 56395), site specific analysis of process fuel gas, and the actual heat input (HHV).

XII. Staged Flaring Operation (EPNs: FLAREXX1 and FLAREXX2)

ExxonMobil will install a flare system with staged operation to provide for the safe control of gases vented from the proposed project during normal operations and during emergency releases. The flare system will consist of a steam-assisted elevated flare (FLAREXX1) and a multi-point ground flare (FLAREXX2). The staged flare system is designed to segregate the continuous flows (high volume) from the intermittent flows (low volume). Segregating these low and high volume streams into different flare dispositions will optimize the amount of gas and steam to hydrocarbon ratio required for good combustion. The elevated flare's pilots are fueled by pipeline quality natural gas and has a destruction and removal efficiency (DRE) of 98% for methane. The multi-point ground flare's pilots will be fueled by pipeline quality natural gas and/or ethane, and will have a DRE of 99%. The CO_2e emissions from the flare account for less than 7% of the total projects CO_2e emissions.

Step 1 – Identification of Potential Control Technologies

- *Low Carbon Assist Gas* – The flares will use pipeline quality natural gas and/or ethane for the pilots and as supplemental fuel, if needed, to maintain appropriate vent stream heating value.
- *Good Operating and Maintenance Practices* – Good combustion practices include appropriate maintenance of equipment and operating within the recommended heating value and flare tip velocity as specified by its design.
- *Staged Flaring* – Use of staged flaring ensures the streams are mitigated appropriately and per design to achieve the stated DRE.

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

- Low-Carbon Fuel
- Good Operation and Maintenance Practices
- Staged Flaring

Use of low-carbon fuel, and good operation and maintenance practices, and staged flaring are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only.

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

<u>Low-Carbon Fuel</u>

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.

<u>Good Operation and Maintenance Practices</u>

Good operation and maintenance practices effectively support the proper operation of the flares and are inherent in the design and operation of the proposed flare system.

<u>Staged Flaring</u>

Staged flaring is economically and environmentally practical for the proposed project.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the elevated flare:

- *Low Carbon Fuels* – The flares will combust pipeline natural gas and/or ethane in the pilots, natural gas will be used as supplemental fuel, if needed, to maintain combustion temperatures.

- *Good Operation and Maintenance Practices* – 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.
- *Staged Flaring* – A staged flare system will be utilized.

ExxonMobil proposes to monitor and record the following parameters to demonstrate continuous compliance with staged flare system operating specifications:

- Continuously monitor and record the pressure of the flare system header,
- Continuously monitor and record the flow to the elevated flare through a flow monitoring system,
- Continuously monitor the steam flow to the elevated flare through a flow monitoring system and record the steam to hydrocarbon ratio,
- Continuously monitor the composition of the waste gas contained in the flare system header through an online analyzer located on the common flare header, sufficiently upstream of the diverting headers to the elevated flare and the multi-point ground flare, and record the heating value of the flare system header,
- Continuously monitor the flow rate to the multi-point ground flare to demonstrate that flow routed to the multi-point ground flare system exceeds 4 psig; however, if a lower pressure can be demonstrated to achieve the same level of combustion efficiency, then this lower limit will be implemented,
- Maintain a minimum heating value and maximum exit velocity that meets 40 CFR § 60.18 requirements for the routine streams routed to the elevated flare including the assist gas flow, and
- Monitor and maintain a minimum heating value of 800 Btu/scf of the waste gas (adjusted for hydrogen) routed to the multi-point ground flare system to ensure the intermittent stream is combustible; however, if a lower heating value limit can be demonstrated to achieve the same level of combustion efficiency, then this lower limit will be implemented.

Using these operating practices above will result in an emission limit for the staged flare system of 90,539 tpy CO_2e. ExxonMobil will demonstrate compliance with the CO_{2e} 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 ethane and waste gas (see Tables 3-3C and 3-3D of the GHG permit application). The equation for estimating CO_2 emissions as specified in 40 CFR 98.253(b)(1)(ii)(A) is as follows:

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

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (short tons/year).
DRE = 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 GHG mass emission limits in TPY associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2 using the GWPs as published on October 30, 2009 (74 FR 56395), site specific analysis of waste gas, and the actual heat input (HHV).

XIII. Engines (EPNs: DIESELXX01, DIESELXX02, DIESELXX03, DIESELXX04, DIESELXX05, DIESELXXFW1, and DIESELXXFW2)

ExxonMobil will install up to five backup generators and two firewater booster pump engines. The backup generators shall have an aggregate power output not to exceed 3.0 MW total, regardless of how many are installed. The generators and engines proposed for use will operate at a low annual capacity factor - approximately one hour per week in non-emergency use. The generators and engines are designed to use diesel fuel, stored in onsite tanks, so that emergency power is available for safe shutdown of the facility in the event of a power outage that may also include natural gas supply curtailments. The firewater booster pump engines will supply power to two new booster pumps that will be added to the existing firewater system. Each firewater booster pump engine will have a power output of 0.45 MW (600 HP) each. The CO_2e emissions from the emergency generators and the two firewater booster pump engines account for less than 0.01% of the total project emissions.

Step 1 – Identification of Potential Control Technologies

- *Low Carbon Fuels* – Use of fuels containing lower concentrations of carbon generate less CO_2, than other higher-carbon fuels. Typically, gaseous fuels such as natural gas or high-hydrogen plant tail gas contain less carbon, and thus lower CO_2 potential, than liquid or solid fuels such as diesel or coal.
- *Good Operating and Maintenance Practices* – Good operating and maintenance practices include appropriate maintenance of equipment and operating within the recommended air to fuel ratio recommended by the manufacturer.

Step 2 – Elimination of Technically Infeasible Alternatives

- *Low Carbon Fuels* – The purpose of the engines is to provide a power source during emergencies, which include site power outages and natural disasters, such as hurricanes. As such, the power source must be available during emergencies. Electricity is not a source that is available during a power outage, which is the specific event for which the backup generators are designed to operate. Natural gas supply may be curtailed during an emergency such as a hurricane; thereby not providing fuel to the engines during the specific event for which the backup generators and firewater booster pump are designed to operate. The engines must be powered by a liquid fuel that can be stored in a tank and supplied to the engines on demand, such as motor gasoline or diesel. Therefore, ExxonMobil proposes to use diesel fuel for the emergency generator engines and firewater booster pump engines, since non-volatile fuel must be used for emergency operations. The use of low-carbon fuel is considered technically infeasible for emergency generator operation and is not considered further for this analysis.
- *Good Operating Combustion Practices and Maintenance* – Is considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Only one option, good operation and maintenance practices, has been identified for controlling GHG emissions from engines; therefore, ranking by effectiveness is not applicable.

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

The single option for control of CO_2 from engines is to follow good operating and maintenance practices.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the engines:

- *Good Operation and Maintenance Practices* – Good operation and maintenance practices for compression ignition engines include appropriate maintenance of equipment, periodic testing conducted weekly, and operating within the recommended air to fuel ratio, as specified by its design.

Using the operating and maintenance practices identified above results in a BACT limit of 952 tpy CO_2e for all engines combined. ExxonMobil will demonstrate compliance with the CO_2 emission limit using the emission factors for diesel fuel from 40 CFR Part 98, Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(ii) is as follows:

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

Where:

CO_2 = Annual CO_2 mass emissions from combustion of diesel fuel (short tons)
Fuel = Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to § 98.3(i).
CC = Annual average carbon content of the liquid fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at § 98.33(a)(2)(ii).
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

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.

XIV. Equipment Fugitives (EPN: BOPXXAREA)

The proposed project will include new piping components for movement of gas and liquid raw materials, intermediates, and feedstocks. These components are potential sources of GHG emissions due to emissions from rotary shaft seals, connection interfaces, valves stems, and similar points. GHGs from piping component fugitives are mainly generated from fuel gas and natural gas lines for the proposed project, but may be emitted from other process lines that are in VOC service.

Step 1 – Identification of Potential Control Technologies

- *Leakless/Sealless Technology*
- *Instrument LDAR Programs*
- *Remote Sensing*
- *Auditory, Visual, and Olfactory (AVO) Monitoring*

Step 2 – Elimination of Technically Infeasible Alternatives

- *Leakless/Sealless Technology* – Leakless technology valves may be incorporated in situations where highly toxic or otherwise hazardous materials are present. These technologies cannot be repaired without a unit shutdown that often generates additional emissions. Fuel gas and natural gas are not considered highly toxic nor hazardous materials, and do not warrant the risk of unit shutdown for repair and therefore leakless valve technology for fuel lines is considered technically impracticable.
- *Instrument LDAR Programs* – Is considered technically feasible.
- *Remote Sensing* – Is considered technically feasible.
- *AVO Monitoring* – Is considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Instrument LDAR programs and remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[4] The most stringent TCEQ LDAR program, 28LAER, provides for 97% control credit for valves, flanges, and connectors.

As-observed audio and visual observations (AVO) means of identifying fugitive emissions are dependent on the frequency of observation opportunities. These opportunities arise as technicians make inspection rounds. Since pipeline natural gas is odorized with very small quantities of mercaptan, as-observed olfactory observation is a very effective method for identifying fugitive

[4] 73 FR 78199-78219, December 22, 2008.

emissions at a higher frequency than those required by an LDAR program and at lower concentrations than remote sensing can detect.

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

As-observed AVO is the most effective approach for GHG sources that are not in VOC service, such as natural gas components. The frequency of inspection rounds and low odor threshold of mercaptans in natural gas make as-observed AVO an effective means of detecting leaking components in natural gas service. The approved LDAR program already implemented at BOP is an effective control for GHG sources that are in VOC service, since these components are monitored in accordance with the existing LDAR program and may not be easily detectable by olfactory means.

Instrument LDAR and/or remote sensing of piping fugitive emissions in fuel gas and natural gas service may be effective methods for detecting GHG emissions from fugitive components; however, the economic practicability of such programs cannot be verified. Specifically, fugitive emissions are estimates only, based on factors derived for a statistical sample and not specific neither to any single piping component nor specifically for natural gas service. Therefore, instrument LDAR programs or their equivalent alternative method, remote sensing, are not economically practicable for controlling the piping fugitive GHG emissions from the project's natural gas components.

Step 5 – Selection of BACT

Based on the economic impracticability of instrument monitoring and remote sensing for fuel gas and natural gas piping components, ExxonMobil proposes to incorporate as-observed AVO as BACT for the piping components associated with this project in fuel gas and natural gas service. The proposed permit contains a condition to implement an AVO program on a weekly basis.

Process lines in VOC service contain a minimal quantity of GHGs. Additionally, process lines in VOC service are proposed to incorporate the TCEQ 28VHP leak detection and repair (LDAR) program for fugitive emissions control in the New Source Review (NSR) permit No. 102982 to be issued by TCEQ. EPA concurs with ExxonMobil's assessment that using the TCEQ 28VHP[5] LDAR program is an appropriate control of GHG emissions. As noted above, LDAR programs would not normally be considered for control of GHG emissions alone due to the negligible amount of GHG emissions from fugitives, and while the existing LDAR program is being

[5] The boilerplate special conditions for the TCEQ 28LAER LDAR program can be found at http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28vhp.pdf. These conditions are included in the TCEQ issued NSR permit.

imposed in this instance, the imposition of a numerical limit for control of those negligible emissions is not feasible.

XV. 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, ExxonMobil, and its consultant, Raven Environmental Services, INC., ("Raven"), and adopted by EPA.

A draft BA has identified twelve (12) 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**
Plant	
Texas Prairie Dawn Flower	*Hymenoxys texana*
Birds	
Red-cockaded Woodpecker Whooping Crane	*Picoides borealis* *Grus americana*
Fish	
Smalltooth Sawfish	*Pristis pectinata*
Mammals	
Louisiana Black Bear Red Wolf	*Ursus americanus luteolus* *Canis rufus*
Amphibians	
Houston Toad	*Bufo houstonensis*
Reptiles	
Green Sea Turtle Kemp's Ridley Sea Turtle Leatherback Sea Turtle Loggerhead Sea Turtle Hawksbill Sea Turtle	*Chelonia mydas* *Lepidochelys kempii* *Dermochelys coriacea* *Caretta caretta* *Eretmochelys imbricate*

EPA has determined that issuance of the proposed permit will have no effect on any of the twelve (12) 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.

XVI. 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 Whitenton Group on behalf of ExxonMobil and reviewed and adopted by EPA.

The facility is adjacent to tidally influenced portions of the Houston Ship Channel (San Jacinto Tidal). These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, subadult or adult stages of red drum (*Sciaenops ocellatus*), shrimp (4 species), coastal migratory pelagics (3 species), and reef fish (43 species). The EFH information was obtained from the NMFS's website (http://www.habitat.noaa.gov/protection/efh/efhmapper/index.html).

Furthermore, these tidally influenced areas have also been identified by NMFS to contain EFH for neonate/young of the year scalloped hammerhead sharks (*Sphyrna lewini*); neonate/young of the year and juvenile blacktip sharks (*Carcharhinus limbatus*) and bull sharks (*Carcharhinus leucas*); and neonate/young of the year and adult Atlantic sharpnose sharks (*Rhizoprionodon terraenovae*) and bonnethead sharks (*Sphyrna tiburo*)

Based on the information provided in the EFH Assessment, EPA concludes that the proposed PSD permit allowing ExxonMobil construction of a new ethylene production unit within the existing Baytown facility will have no adverse impacts on listed marine and fish habitats. The assessment's analysis, which is consistent with the analysis used in the BA discussed above, shows the project's construction and operation will have no adverse effect on EFH.

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.

XVII. 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 Atkins on behalf of ExxonMobil submitted on April 8, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 25 acres of land within and adjacent to the construction footprint of the existing facility. Atkins conducted a field survey of the property, and a visual impacts survey and desktop review within a 1.5-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 results of the field survey, no archaeological resources or historic structures were found within the APE. Based on the visual survey and cultural review, one historic site was identified to be potentially eligible for listing on the National Register, but it is outside the APE (approximately 1.5 miles away).

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 ExxonMobil will not affect properties potentially eligible for listing on the National Register.

On April 9, 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.

XVIII. 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.

XIX. Conclusion and Proposed Action

Based on the information supplied by ExxonMobil, our review of the analyses contained 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 ExxonMobil 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 Facility Emission Limits

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

Table 1. Facility Emission Limits

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
XXAF01 XXBF01 XXCF01 XXDF01 XXEF01 XXFF01 XXGF01 XXHF01	XXAF01-ST XXBF01-ST XXCF01-ST XXDF01-ST XXEF01-ST XXFF01-ST XXGF01-ST XXHF01-ST	Steam Cracking Furnaces	CO_2	982,000[3]	987,968[3]	Furnace Gas Exhaust Temperature ≤ 340 °F. Each furnace limited to a maximum firing rate of 515 MMBtu/hr. See permit conditions III.A.1.h. and j.
			CH_4	48[3]		
			N_2O	16[3]		
XXAB-DEC XXCD-DEC XXEF-DEC XXGH-DEC	XXAB-DEC XXCD-DEC XXEF-DEC XXGH-DEC	Furnace Decoke Vents	CO_2	796[4]	2,120[4]	Proper furnace design and operation. See permit conditions III.A.1.a. through III.A.1.l.
			CH_4	4[4]		
			N_2O	4[4]		
FLAREXX1 FLAREXX2	FLAREXX1 FLAREXX2	Staged Flare System	CO_2	86,574[5]	90,539[5]	Use of Good Combustion Practices. See permit condition III.A.3.
			CH_4	115[5]		
			N_2O	5[5]		
HRSG05	HRSG05	Train 5 Duct Burners	CO_2	397,231	397,709	Maintain a minimum thermal efficiency of 70%. See permit condition III.A.2.g.
			CH_4	8		
			N_2O	1		
DIESELXX01 DIESELXX02 DIESELXX03 DIESELXX04 DIESELXX05	DIESELXX01 DIESELXX02 DIESELXX03 DIESELXX04 DIESELXX05	Backup Generator Engines	CO_2	223[6]	554[6]	Use of Good Operating and Maintenance Practices. See permit condition III.A.4.
			CH_4	1[6]		
			N_2O	1[6]		
DIESELXXFW1 DIESELXXFW2	DIESELXXFW1 DIESELXXFW2	Firewater Booster Pump Engines	CO_2	67[7]	398[7]	Use of Good Operating and Maintenance Practices. See permit condition III.A.4.
			CH_4	1[7]		
			N_2O	1[7]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
BOPXXFUG	BOPXXFUG	Fugitive Emissions	CH_4	No Emission Limit Established[8]	No Emission Limit Established[8]	Implementation of LDAR/AVO program. See permit condition III.A.5.
Totals[9]			**CO_2**	**1,466,916**	**CO_2e 1,479,665**	
			CH_4	**179**		
			N_2O	**29**		

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. The GHG Mass Basis TPY limit and the CO_2e TPY limit for the steam cracking furnaces applies for all eight furnaces combined.
4. The GHG Mass Basis TPY limit and the CO_2e TPY limit for the furnace decoke vents is for all four furnace decoke vents combined.
5. The GHG Mass Basis TPY limit and the CO_2e TPY limit are for the entire staged flare system (EPNs: FLAREXX1 and FLAREXX2).
6. Up to five generators are allowed, however; total power output will not exceed 3.0 MW for all generators combined. The GHG Mass Basis and CO_2e TPY emissions stated in this table are for all Emergency Generator Engines combined regardless of the number installed.
7. The GHG Mass Basis and CO_2e TPY emissions stated in this table are for both Firewater Booster Pump Engines (EPNs: DIESELXXFW1 and DIESELXXFW2) combined.
8. Fugitive process emissions from EPN BOPXXFUG are estimated to be 1 TPY of $CH_{4,}$ and 21 TPY CO_2e. In lieu of an emission limit, the emissions will be limited by implementing 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.