Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the ExxonMobil Chemical Company, Mont Belvieu Plastics Plant

Permit Number: PSD-TX-103048-GHG

July 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) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for greenhouse gas (GHG) emissions for a proposed construction project at its Mont Belvieu Plastics Plant (MBPP). 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 Mont Belvieu Plastics Plant would involve construction of a new polyethylene unit at the existing facility. ExxonMobil would be adding the following emission units: three flameless thermal oxidizers, a regenerative thermal oxidizer, an elevated flare, a multi-point ground flare, two boilers, analyzer catalytic oxidizers, and fugitives. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of GHG emission sources at the MBPP.

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 initially 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 initial 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
Mont Belvieu Plastics Plant
P.O. Box 1653
Baytown, TX 77580-1653

Physical Address:
13330 Hatcherville Road
Mont Belvieu, TX 77580

Contact:
Benjamin Hurst
Air Permit Advisor
ExxonMobil Chemical Company
(281) 834-6110

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

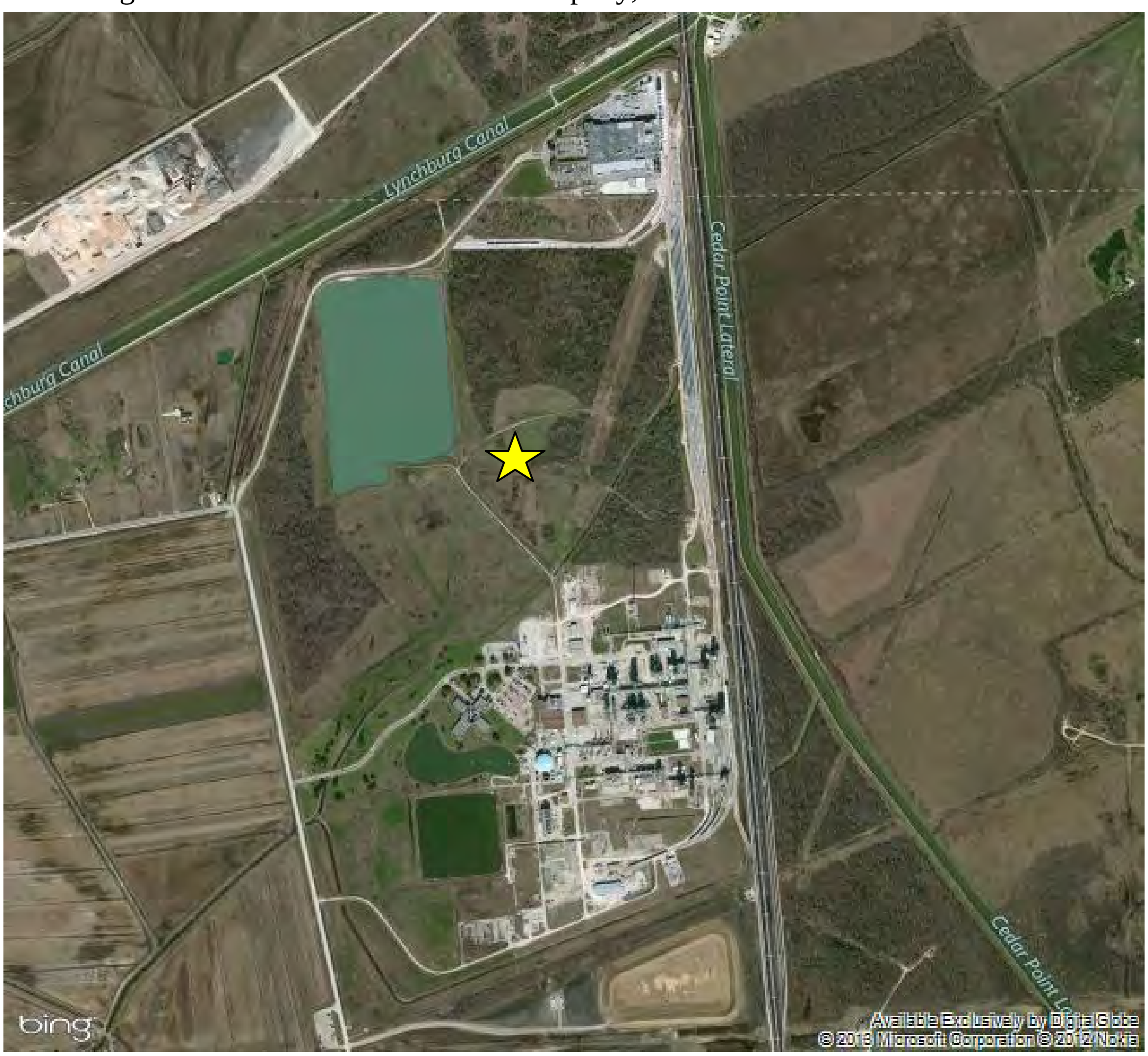
The ExxonMobil, Mont Belvieu Plastics Plant is located in Chambers County, Texas. The geographic coordinates for this facility are as follows:

Latitude: 29º 52' 43" North
Longitude: - 94º 55' 12" West

Chambers 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. ExxonMobil Chemical Company, Mont Belvieu Plastics Plant Location



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

EPA concludes that ExxonMobil's application is subject to PSD review for the pollutant GHGs, because the project would lead to a net emissions increase of GHGs for a facility as described at 40 CFR § 52.21(b)(23) and (49)(iv). Under the project, GHG emissions are calculated to increase over zero tpy on a mass basis and to exceed the applicability threshold of 75,000 tpy CO_2e (ExxonMobil calculates CO_2e emissions of 138,216 tpy). 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 52.21(b)(23) must be in place prior to construction for this applicability analysis and for the source's authorization to construct to be valid.[1]

EPA Region 6 takes into account the policies and practices reflected in the EPA document "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with recommendations 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 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

The proposed GHG PSD permit, if finalized, will allow ExxonMobil to construct a new polyethylene production unit. The new unit will produce polyethylene in low pressure, gas-phase fluidized bed reactors. The proposed facilities include feed purification, polymerization, resin degassing, additives addition, pelletization, blending, storage and shipping consisting of the following emission units: three flameless thermal oxidizers, a regenerative thermal oxidizer, an elevated flare, a multi-point ground flare, two boilers, analyzer catalytic oxidizers, and fugitives.

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

The new polyethylene production unit increases the plant capacity adding approximately 1.75 million tons per year of polyethylene production.

More specifically, transition metal halides and metal alkyls are impregnated onto catalyst support particles similar to fine sand. After manufacture, the catalyst is measured and conveyed into the reactor with an inert gas. The catalyst initiates the reaction of monomer (ethylene) and co-monomers (butene, hexene) in the reactor. Potential trace components that may impact the polymerization process are removed from reactor feed streams in the purification area. This purification process takes place in packed bed vessels. The reaction of gases involves polymerization, which is the linking or bonding of molecules to produce the polymer. Non-reactive components are used to control catalyst activity and/or act as a heat removal medium. In certain products, a metal alkyl is injected in small amounts to scavenge catalyst impurities and act as a co-catalyst. The polymer produced in the reactor is in the form of granules suspended by circulating gases used to remove heat. The polymer particles in the circulating gas form a fluidized bed in the reactor. Granular polyethylene is periodically removed through a series of tanks, along with entrained gas.

Unreacted gases are removed from the gas/resin stream leaving the reactor by degassing purge vessels that strip the gas from polyethylene product using an inert gas. Stripped gases are recovered with a vent recovery system. Some of the unrecovered residual hydrocarbon lean gases are routed through a vent collection system for destruction in a flameless thermal oxidizer (FTO) system, an elevated flare, and/or the multi-point ground flare. A very small amount of residual hydrocarbon remains in the resin after purging.

Granular resin is air-conveyed from the purger area into silos (feed bins). Bag filters on the bins control particulate emissions. The extruder uses mechanical work to melt the plastic and push it through a die-plate containing small holes. The plastic extrudes through these holes into spaghetti-like strands. Most of the residual hydrocarbon that may evolve from purged resin, during conveying is routed to a regenerative thermal oxidizer (RTO). The strands are cut with a series of rotating knives into small pieces known as pellets. These pellets are then conveyed into product silos. The material is air-conveyed from the product silos to loadout. The product silos and load out stations are equipped with bag filters and cyclones to minimize the emission of particles to the atmosphere.

A description of the emission points is provided below:

<u>Regenerative Thermal Oxidizer (EPN: RUPK71)</u>

The regenerative thermal oxidizer will control the residual VOC emissions from the powder hopper bag filter, polyethylene conveying system air vents, and extruder feed vents, all of which typically have less than 130 ppmv of residual hydrocarbons. Supplemental fuel is added to the regenerative thermal oxidizer to ensure sufficient chamber temperature. No supplemental oxygen is necessary to enhance the combustion process.

Vent Collection System Consisting of Flameless Thermal Oxidizers (EPNs: 3UF61A, 3UF61B, and 3UF61C), Assisted Flare (EPN: 3UFLARE62), and Multi-point Ground Flare System (EPN: 3UFLARE63)

Multiple hydrocarbon vent streams from routine continuous (e.g., purger vent) and intermittent (e.g., feed purification bed regeneration, startup/shutdown, etc.) operations will be collected by a Vent Collection System. The Vent Collection System is comprised of two separate headers: a High Pressure (HP) Vent Header and a Low Pressure (LP) Vent Header.

High Pressure Vent Header

The HP Vent Header is designed to receive high load, short duration vent streams, also referred to as “high volume, high pressure” (HVHP) vent stream from the reactors and the high capacity feed supply depressure. The primary control device that will control VOC emissions on the HP Vent Header is a multi-point ground flare system (EPN: 3UFLARE63).

Multi-point Ground Flare System (EPN: 3UFLARE63)

The multi-point ground flare system uses an array of high pressure burners to produce short, highly efficient flames. Pressure assisted burners utilize the flare gas pressure to ensure high exit velocity at the burner exit. The high velocity produces the energy required to promote high air entrainment and mixing in the combustion zone. This entrainment/mixing energy in the combustion zone is the key to producing an efficient, smokeless flame. The multi-point ground flare has a minimum flare combustion efficiency of 99.5% for hydrocarbons containing three or less carbon molecules (e.g. methane).

Low Pressure Vent Header

The LP Vent Header will receive routine continuous vent streams from the process, as well as routine intermittent vent streams. The streams are also referred to as “low volume, low pressure” (LVLP) streams. A high VOC control efficiency will be achieved through the use of three flameless thermal oxidizers (FTOs) with an elevated flare serving as a secondary control device. The LP Vent Header will be equipped with on-line analyzers to provide real time measurement of the heat content and speciation of vent streams. This will allow for supplemental natural gas injection, if required, to maintain minimum heating value content in the vent gas.

Flameless Thermal Oxidizers (EPNs: 3UF61A, 3UF61B, and 3UF61C)

The flameless thermal oxidizers (FTOs) will be used to control emissions from unrecovered waste gas from the process. The patented technology of the proposed FTO consists of a packed-bed, refractory-lined reactor filled with porous, inert ceramic media. Organic compounds are oxidized into CO_2 and water vapor. At startup, the ceramic packing in the oxidizer vessel is heated to the required operating temperature with a natural gas fired burner. The FTOs have a destruction and removal efficiency (DRE) of 99.99% for hydrocarbons containing three or less carbon molecules (e.g. methane).

Elevated Flare (EPN: 3UFLARE62)

The elevated flare provides additional capability to control all vent streams during normal operation of the low pressure (LP) vent header and is the last control disposition within the vent collection system. This flare has a destruction and removal efficiency (DRE) of 99% for hydrocarbons with three or less carbon atoms and this flare requires supplemental natural gas during periods of low heating value content. Air blowers or steam assist will be provided as part of the elevated flare system.

Boilers (EPNs: RUPK31 and RUPK32)

Two boilers each with a design firing capacity of 98 MMBtu/hr (HHV basis) will be used to produce steam for the proposed project. The boilers will fire pipeline quality natural gas.

Analyzer Catalytic Oxidizers (EPN: PEXANALZ)

The proposed project design contains up to 35 analyzer catalytic oxidizers distributed throughout the process equipment. There will be up to 12 feed analyzers and up to 23 process analyzers that might incorporate the catalytic oxidizers. Where applicable, analyzer vent streams are either returned to process or vented to the Vent Collection System. Analyzer streams with very low hydrocarbon content that cannot be returned to process or vented to the Vent Collection System or atmosphere will contain TRACErase™ technology or similar technology to destroy the VOC emissions prior to release to the atmosphere. TRACErase™ technology uses a catalytic combustion process to oxidize vented streams. The analyzer catalytic oxidizers utilize a continuous heat source (catalytic converter) to allow effective oxidation of source streams. The analyzer catalytic oxidizers have a destruction and removal efficiency (DRE) of 98% for hydrocarbons.

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 and BACT Discussion

The majority of the contribution of GHGs associated with the project is from combustion sources (i.e., flameless thermal oxidizers, regenerative thermal oxidizer, ground flare, elevated flare, and boilers). 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:

- Flameless Thermal Oxidizers (EPNs: 3UF61A, 3UF61B, and 3UF61C)
- Regenerative Thermal Oxidizer (EPN: RUPK71)
- Multi-point Ground Flare System (EPN: 3UFLARE63)
- Assisted Elevated Flare (EPN: 3UFLARE62)
- Boilers (EPNs: RUPK31 and RUPK32)
- Equipment Fugitives (EPN: PEXFUGEM)
- Analyzer Catalytic Oxidizers (EPN: PEXANALZ)

IX. Vent Collection System Consisting of Flameless Thermal Oxidizers (EPNs: 3UF61A, 3UF61B, and 3UF61C), Assisted Elevated Flare (EPN: 3UFLARE62), and Multi-point Ground Flare System (EPN: 3UFLARE63) BACT Analysis

The purpose of the vent collection system is to segregate and control VOC-containing vent streams from the process to the appropriate control device to maximize VOC destruction. Due to the integration of computer control applications that manage these control devices and operation of the vent collection system, this BACT analysis focuses on the combined vent collection system as a collective emission source. The vent collection system will consist of a low pressure (LP) vent header and a high pressure (HP) vent header. The LP vent header will route streams to the flameless thermal oxidizers (FTOs) and the elevated flare. The HP vent header will route streams to the multipoint ground flare. The elevated flare will provide backup to the FTOs during periods of excess venting to the LP vent header, as well as backup to the HP vent header when the heat value, header pressure, and/or the flow rate drops below operational or compliance targets. The primary emissions will be CO_2, with some CH_4 from any incomplete combustion, and N_2O will be emitted in trace quantities due to partial oxidation of nitrogen. The FTOs will have a hydrocarbon destruction and removal efficiency (DRE) of 99.99%. The multi-point ground flare has a minimum hydrocarbon DRE of 99.5%. For the purposes of this analysis of GHG emissions, the elevated flare is conservatively presumed to have a hydrocarbon DRE of 98% for the hydrocarbons being combusted.

As part of the PSD review, ExxonMobil provides in the GHG permit application a 5-step top-down BACT analysis for the FTOs, elevated flare, and multi-point ground flare that are part of the vent collection system. EPA has reviewed ExxonMobil's BACT analysis for these emission units, 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)* – CCS is an available add-on control technology that is applicable for all of the site's affected combustion units.
- *Use of Low Carbon Assist Gas* – The proposed control devices combust natural gas to maintain proper control device temperature and destruction efficiency. Natural gas is the lowest carbon fuel available for the proposed project.
- *Good Operating and Maintenance Practices* – Good combustion practices include appropriate maintenance of equipment, operation at the designed temperature and oxygen concentration for the FTOs, operation based on designed velocity and heating value for the elevated flare, and operation based on recommended design pressure and heating value for the multi-point ground flare.
- *Staged Operation* – The proposed project will install a vent collection system with staged operation. By segregating these low and high volume streams into different control device dispositions, the proposed project will optimize the amount of assist gas (natural gas) and air/steam to hydrocarbon ratio required for good combustion. This will minimize the amount of CO_2 generated by the destruction of vent streams.
- *Energy Efficient Design* –Use of a variable flow air blower with a computer control application can control the excess oxygen available during combustion.
- *Vent Gas Recovery (VGR)* – Recover routine continuous vent streams prior to combustion in a control device and utilize the heat content to reduce natural gas consumption at the boilers thereby avoiding GHG emissions.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for this project.[2]

Carbon Capture and Storage

CCS 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)."[3] 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 vent control 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 facility; the third approach, post-combustion capture, is applicable to the FTOs, flares, and other combustion units covered by this permit application.

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 are multiple mature oil and gas fields that could be suitable targets for enhanced oil recovery projects or that could have suitable brine formations either below or above known production zones, that could serve as storage reservoirs. These sites, however, would require intensive evaluation and would very likely require substantial remedial work to provide the high degree of site and formation integrity necessary for secure storage. There is a large body

---

[2] 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.

[3] 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)

of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[4]

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- CO_2 capture and storage (up to 90%)
- Low-Carbon Assist Gas
- Good Operating and Maintenance Practices
- Staged Operation
- Energy Efficient Design
- Vent Gas Recovery (VGR)

CCS is capable of achieving 90% reduction of generated CO_2 emissions and thus is considered to be the most effective control method. Use of low-carbon assist gas, energy efficient design, staged operation, vent gas recovery, and good combustion and maintenance practices are all considered effective, can be used in tandem, and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only (and is not especially meaningful, given that these technologies are not mutually exclusive).

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

<u>Carbon Capture and Storage</u>

ExxonMobil developed and submitted an evaluation of CCS costs for consideration in step 4 of the BACT process. In their evaluation, the majority of the cost for CCS was attributed to the capture and compression facilities that would be required to be constructed and operated. The applicant has reliably shown that carbon capture and compression facilities would include CO_2 compressor and intercoolers (estimated cost of $32.9 million), amine absorber system (estimated cost of $61.3 million), CO_2 regeneration and purification system (estimated cost of $21.5 million), and blower, piping, and ducting (estimated cost of $14.8 million). Additional utilities would need to be constructed as well. The additional utilities would require construction of a new utility plant – consisting of a boiler with boiler feed water treatment and a blower – estimated to cost $27.7 million. The construction of a new cooling tower, utility header, and piping would cost an estimated $50.1 million. The cost for the new pipeline would be $18.3 million, based on an 8-inch diameter pipeline going 20 miles (distance to nearest CO2 pipeline stem). The total capital cost for carbon capture is estimated to be $208,300,000, which includes

[4] 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

compression equipment, amine treating, regeneration and purification system, and additional utilities. The total annual cost of CCS capital and operating expenses would be $50,800,000 per year. The addition of CCS would increase the project capital costs by more than 25%. According to the applicant, such an increase in capital cost would make the project economically unviable. EPA Region 6 reviewed ExxonMobil's CCS cost estimate and agrees that it adequately approximates the cost of a CCS control for this project and demonstrates that those costs are excessive in relation to the overall cost of the proposed project. As noted below, these same reasons for rejecting CCS apply equally with respect to the other emission areas at ExxonMobil.

In addition to maintaining that CCS would be economically infeasible for this project, ExxonMobil also asserts that CCS can also be eliminated as BACT based on the environmental impacts from a collateral increase of National Ambient Air Quality Standards (NAAQS) pollutants. According to the applicant, implementation of CCS would increase emissions of NOx, CO, VOC, PM_{10}, and SO_2 by as much as 21% from the additional utilities and energy demands that would be required to operate the CCS system. The increase in these criteria pollutants, according to the applicant, 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.

EPA notes that where GHG control strategies affect emissions of other regulated pollutants, trade-offs in selecting GHG pollution controls can be legitimately taken into account. See PSD Permitting Guidance at pp. 40-42. Here, the 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. Many of the devices whose carbon emissions have triggered PSD permitting for GHGs (the thermal oxidizers and flares, for example) are pollution control measures to control emissions of ozone precursors. Thus, there is special sensitivity about employing control measures that would result in emission increases of ozone precursors. EPA reviewed ExxonMobil's cost analysis and the estimated pollutant increases that would result from the implementation of CCS, and concludes that CCS can be eliminated as BACT for this project due to the cost increase to the project. It is not necessary, therefore, to also reject CCS based on the projected collateral emission increases of ozone precursors in an ozone non-attainment area, but EPA notes that the applicant's concerns are legitimate factors for consideration.

<u>Low-Carbon Assist Gas</u>

The use of natural gas as an assist gas is inherent in the design and operation of the FTOs and flares at MBPP. There are no negative economic, environmental, or energy impacts associated with this option.

Good Operating and Maintenance Practices

Good operation and maintenance practices for the FTOs and flares 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. There are no negative economic, environmental, or energy impacts associated with this option.

Staged Operation

There are no negative economic, environmental, or energy impacts associated with this option.

Energy Efficient Design

Energy efficient design will be incorporated into the vent collection system, specifically, utilization of air blowers with computerized control to control the excess oxygen based on the incoming feed to the FTOs. There are no negative economic, environmental, or energy impacts associated with this option.

Vent Gas Recovery (VGR)

The proposed project incorporates a state-of-the art technology to recover unreacted gases from the polyethylene reactor system to minimize air emissions. The vent gas recovery system is inherent in the design and operation of the proposed polyethylene plant, and includes recovery compressors, refrigeration systems, heat exchangers, pumps and vessels, to return unreacted hydrocarbon liquids back to the process. Specifically vent gases will be filtered by a compressor intake filter, cooled in a pre-cooler, compressed in a multi-stage recovery compressor with an inter-stage cooler, and then condensed using ethylene refrigeration in order to recover and return unreacted hydrocarbon liquids back to the process. The proposed polyethylene plant includes additional recovery technologies such as a reactor vent column and two-staged membrane unit to achieve incremental increases in gas recovery. The reactor vent column is used to control nitrogen concentration of reactor content, with a small vent to the flare. The vent column scrubs vent gases through a packed column using recovered liquids to 'wash' and extract hydrocarbon present in the vent stream to the flare for routing back to the process. The two-staged membrane unit is a separation system to further enhance recovery of lighter molecules by separating a low pressure hydrocarbon rich stream from a high pressure nitrogen rich stream in the first membrane module. The hydrocarbon stream is recycled back into the process. The high pressure nitrogen stream goes to the second stage membrane module to purify the nitrogen for use in the process. Finally, after cycling through the vent gas recovery system, and two-staged membrane system, unrecovered vapor, as the low pressure permeate from the second module is sent to the control device system. This system will avoid the generation of approximately 810,000 tons CO_2e/yr. Vent gas recovery will be utilized at the proposed facility; however, there will be a small amount of vent gas recovery system "off-gas" that will not be able to be recovered further.

The vent gas that ExxonMobil is unable to collect by the vent gas recovery system, vent column, and two-staged membrane system are routed to another vent collection system for destruction in an FTO, elevated flare, or the multi-point ground flare. ExxonMobil explored the possibility of routing the vent gas recovery system "off-gas" to the boilers as supplemental fuel. ExxonMobil determined that a compression system would be needed with a total capacity to process up to 1,800 pounds per hour of "off-gas", which is equivalent to 1,000 pounds per hour of natural gas. This flow rate is based on the estimated amount of vent gas the boilers could reliably fire in place of natural gas. The use of the "off-gas" as fuel could result in 9,000 tons per year of CO_2e avoided. ExxonMobil provided a cost analysis for such a system to utilize the "off-gas" as a fuel in the boilers.[5] ExxonMobil has demonstrated that the costs to recover the "off-gas" as a fuel are disproportionately high; therefore, using the "off-gas" as a fuel in the boilers is eliminated as a control option.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the vent collection system:

- *Low Carbon Assist Gas* – Pipeline quality natural gas, or a fuel with a lower carbon content than pipeline quality natural gas, as supplemental fuel to the FTOs and flares.
- *Good Operation and Maintenance Practices* –
    - *LP Vent Header* –
        - Monitor the composition and heat value of the vent gas contained in the LP Vent Header through online analyzers and record the heating value.
    - *FTOs* –
        - Monitor and record the vent gas flow to the FTO through a flow monitoring system;
        - Monitor the excess oxygen at the exhaust stack of the FTOs and maintain excess oxygen above the minimum demonstrated for the designated DRE during the performance test;
        - Monitor the temperature of the FTOs and maintain the temperature above the minimum demonstrated temperature or manufacturer recommended temperature;

[5] See pages 4-11 through 4-12 of the revised application submitted March 2013 and email from Benjamin Hurst to Jeffrey Robinson dated May 23, 2013. The revised application is available at http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-mont-belvieu-revisedapp03082013.pdf
The email is available at http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-mont-belvieu-vent-gas-recovery.pdf

- Visually inspect burners during routine preventative maintenance outages and prior to start-up to ensure proper operation.
- *Elevated Flare –*
  - Monitor and record the flow to the elevated flare through a flow monitoring system;
  - 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 flow;
  - Monitor and record the composition and heating value of the vent gas (including assist gas) within the LP Vent Header;
  - Monitor pilots for presence of flame.
- *Multi-point Ground Flare –*
  - Monitor the pressure 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 may be implemented after approval by EPA;
  - Monitor and record the pressure of the HP Vent Header;
  - Monitor and record the composition of the vent gas within the HP Vent Header;
  - Monitor and maintain a minimum heating value of 800 Btu/scf of the off gas including assist 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 may be implemented after approval by EPA;
  - Monitor pilots for presence of flame.

- *Staged Flaring* – A staged flare system will be utilized.
  - *Operation of the control applications to manage disposition of the vent streams among the Vent Headers and the control devices.*
  - *Manual overrides and/or manual bypasses will be employed only during unexpected and unplanned failure of the computer control system to properly operate.*
- *Energy Efficient Design –*
  - *Use FTO variable flow air blowers with computer control application to control the excess oxygen on the incoming feed.*
  - *Use computer control application to minimize assist gas firing in the FTO.*
  - *Use variable assist at elevated flare with computer control application.*
- *Vent Gas Recovery –*
  - *Vent gases will be filtered by a compressor intake filter, cooled in a pre-cooler, compressed in a multi-stage recovery compressor with an inter-stage cooler, and*

- *then condensed using ethylene refrigeration in order to recover and return unreacted hydrocarbon liquids back to the process.*
- *A reactor vent column will be utilized to scrub vent gases using recovered liquids to extract hydrocarbons in the vent stream for routing back into the process.*
- *A two-stage membrane separation system will be utilized to recover a low pressure hydrocarbon stream from a high pressure nitrogen stream. The hydrocarbon stream is recycled back to the process.*

BACT Limits and Compliance:

EPA is proposing that ExxonMobil will monitor and record the following parameters for the multi-point ground flare system, flameless thermal oxidizer system, and the assisted elevated flare system to demonstrate continuous compliance with the vent collection system operating specifications:

- Continuously monitor and record the pressure of the HP vent header,
- Continuously monitor and record the vent gas flow to the elevated flare and FTOs through a flow monitoring system,
- Continuously monitor and record the excess oxygen at the exhaust stack of the FTOs and maintain excess oxygen above the minimum demonstrated during the initial performance testing.
- Continuously monitor and record the temperature of the FTOs and maintain the temperature above the minimum demonstrated during the initial performance testing.
- Continuously monitor flare pilots for continuous presence of flame,
- Continuously monitor the composition and heating value of the waste gas combusted in the flare through online analyzers located on the LP vent header and the HP vent header, and record the heating value of the flare system header,
- Continuously monitor the pressure 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 shall be implemented following EPA approval,
- 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, and
- Monitor and maintain a minimum heating value of 800 Btu/scf of the waste gas including assist 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 through an equivalency determination to achieve the same level of combustion efficiency, then this lower limit shall be implemented following approval by EPA.

Using these operating practices above will result in an emission limit for the vent collection system of 104,413 tpy CO_2e. This emission limit is a reduced emissions cap for the FTOs, elevated flare, and the multi-point ground flare combined. The FTOs will have a combined emission limit of 91,660 tpy of CO_2, the elevated flare will have an emission limit of 6,304 tpy CO_2, and the multi-point ground flare will have an emission limit of 7,735 tpy of CO_2.

ExxonMobil will calculate the CO_2 emissions from the flares (EPNs: 3UFLARE62 and 3UFLARE63) using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1, or site specific fuel analysis for natural gas, and the site specific fuel analysis for waste gas (see Tables A-2, and A-4 of the GHG permit application). The equation for estimating CO_2 emissions from the flares is equation Y-1a, as specified in 40 CFR 98.253(b)(1)(ii)(A) is as follows:

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

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (short tons/year).
0.98 = Assumed combustion efficiency of the elevated flare (use 0.995 for the multi-point ground 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, for the flares (EPNs: 3UFLARE62 and 3UFLARE63), associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98 Subpart C, Table C-2 or site specific analysis of natural gas, site specific analysis of waste gas, and the actual heat input (HHV) and using equations Y-4 and Y-5 respectively, from 40 CFR Part 98 Subpart Y.

The FTOs (EPNs: 3UF61A, 3UF61B, and 3UF61C) will have a combined emission limit of 91,660 tpy of CO_2. ExxonMobil will demonstrate compliance with the CO_2 emission limit for the FTOs using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1 or site specific fuel analysis for natural gas, and the site specific fuel analysis for waste gas (see Table A-1 of the GHG permit application). The equation for estimating CO_2 emissions for the FTOs is equation C-5, 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 emission limits associated with CH_4 and N_2O, for the FTOs, are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 or site specific analysis for natural gas, site specific analysis of waste gas, and the actual heat input (HHV) using equation C-8 from 40 CFR Part 98 Subpart C.

To calculate the CO_2e emissions, the 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 (74 FR 56374 October 30, 2009). Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month average, rolling monthly.

X. Regenerative Thermal Oxidizer (EPN: RUPK71) BACT Analysis

The regenerative thermal oxidizer (RTO) is a control device that will be installed to meet BACT for another PSD pollutant (volatile organic compounds (VOC)). The RTO will control criteria pollutant emissions from the powder hopper bag filter, conveying are vents, and extruder feed vents. These vents typically all emit less than 130 ppmv of residual hydrocarbons. The RTO will have a hydrocarbon destruction and removal efficiency (DRE) of 99% or less than 2 ppmv methane in the outlet concentration.

Step 1 – Identification of Potential Control Technologies

- *Use of Low Carbon Assist Gas* – The proposed RTO combusts natural gas to maintain proper control device temperature and destruction efficiency. Natural gas is the lowest carbon gas available for the proposed project.
- *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
- *Energy Efficient Design* – Energy efficiency is inherent in the operation of an RTO. Specific technologies include feed preheating, insulation, and optimization of the fuel/air mixture.
- *Carbon Capture and Storage (CCS)* – CCS is an available add-on control technology that is applicable for all of the sites affected combustion units.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step are considered technically feasible. CCS will not be considered further based on the evaluation in section IX above.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Use of Low Carbon Assist Gas;
- Use of Good Operating and Maintenance Practices; and
- Energy Efficient Design.

All options identified for controlling GHG emissions from the RTO are considered effective and have a range of efficiency improvements which cannot be directly quantified, and can all be used together. Therefore, a ranking is unnecessary.

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

Although all fossil fuels contain carbon, the natural gas fired in the proposed RTO is a low carbon assist gas. The use of low carbon assist gas and good operating and maintenance practices are inherent in the design and operation of the RTO at MBPP. Energy efficient designs will be incorporated, specifically, feed preheat, insulation, and improved process control.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the thermal oxidizer:

- Use of Low Carbon Assist Gas - Only pipeline quality natural gas will be utilized in the RTO burners.
- Good Operating and Maintenance Practices - ExxonMobil will ensure good operation and maintenance practices through the use of a flow monitoring system to record the vent gas flow and the supplemental fuel gas flow. The burners will be inspected, at a minimum, annually to ensure proper performance.
- Energy Efficient Design - To ensure efficient operation, ExxonMobil will monitor the combustion chamber temperature of the RTO and maintain it at or above 1,400^{o}F. The RTO will also utilize the following technologies:
    - Feed Preheat - Hot purified air releases thermal energy as it passes through a media bed (typically ceramic) in the outlet flow direction. The media bed is then used to preheat inlet gases. Altering airflow direction into the media beds maximizes energy recovery.
    - Insulation of the RTO to retain heat within the unit, thereby reducing firing demand.

Using these operating practices will result in an annual emission limit of 2,552 tpy CO_2e. Compliance shall be determined by the monthly calculation of GHG emissions using equation C-5, 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 emission limits associated with CH_4 and N_2O, for the RTOs, are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 or site specific analysis for natural gas, site specific analysis of waste gas, and the actual heat input (HHV) using equation C-8 from 40 CFR Part 98 Subpart C.

To calculate the CO_2e emissions, the 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 (74 FR 56374 October 30, 2009). Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month average, rolling monthly.

XI. Boilers (EPNs: RUPK31 and RUPK32) BACT Analysis

The proposed boilers will only burn pipeline quality sweet natural gas. CO_2 will be emitted from the boilers since it is a combustion product of any carbon containing fuel. CH_4 will be emitted from the boilers as a result of any incomplete combustion. N_2O will be emitted from the boiler in trace quantities due to partial oxidation of nitrogen in the air which is used as the oxygen source for the combustion process.

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 site's affected combustion units.
- *Low Carbon Fuels* – The boilers will fire pipeline quality natural gas.
- *Good Combustion Practices and Maintenance* - 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.
- *Energy Efficient Design* – The boilers will produce steam for use throughout the plant. In addition to the inherent efficiency of the boilers themselves, heat exchangers/economizers

will be used to preheat feed water prior to entering the steam drum and to extract as much heat as practical from the boiler flue gas.

Carbon Capture and Storage

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

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible. CCS will not be considered further based on the evaluation in section IX above.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Energy efficient design, use of low-carbon fuel, and good combustion practices are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, ranking 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

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 not only of GHGs, but of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing further environmental benefits.

Good Combustion Practices

Good combustion practices effectively support the energy efficient design. Thus, the economic and environmental practicability related to energy efficient design also applies to the use of good combustion practices.

Energy Efficient Design

The boilers will incorporate the following technologies; feedwater preheat, such as an economizer. 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 both GHGs and other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing further environmental benefits.

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	BACT Control(s)	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 the VHP boiler - monitor and maintain a thermal efficiency of 77% 12-month rolling average basis	2012	PSD-TX-748-GHG

ExxonMobil's boilers will each meet a thermal efficiency of 77% on a 12-month rolling average basis. This value is the same as that established for BASF and Chevron Phillips in the table above. EPA believes that this is a reasonable measure of efficient operation based on our evaluation.

The following specific BACT practices are proposed for the boilers:

- *Low Carbon Fuels* – The boilers will fire pipeline quality natural gas.
- *Good Combustion Practices and Maintenance* – The use of good combustion practices includes periodic 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. These practices will include:
  - Boiler inspection to occur, at a minimum, of every 5 years. Inspection will include:
    - Checking the integrity of burner components (tips, tiles, surrounds);
    - Inspecting burner spuds for potential fouling;
    - Inspecting burner air doors and lubrication;
    - Inspecting all burners before closing main door to check for potential debris;
    - Inspecting combustion air ducting and dampers; and
    - Checking burner spud/orifice sizes.

- Records will be maintained for any maintenance activity completed on the burners. The burners are to be inspected during routine scheduled maintenance periods.
- *Energy Efficient Operation* – The boiler will produce steam for use throughout the plant. Specific technologies utilized will include the following:
  - *FeedwaterPreheat* - Use of heat exchangers/economizers to preheat incoming feedwater to minimize fuel usage in the firebox.
  - *Flue Gas Heat Recovery* - Use of heat exchangers/economizers to use heat in the combustion gases in the boiler flue gas.

BACT for the boilers will be to maintain no less than a 77% thermal efficiency (HHV basis) on a 12-month rolling average for each boiler. ExxonMobil elects to demonstrate compliance with a 77% thermal efficiency on the boilers using the following equation:

$$Boiler\ Efficiency\ (HHV\ basis) = \frac{(steam\ flow\ rate\ x\ steam\ enthalpy) - (feedwater\ flowrate\ x\ feedwater\ enthalpy)}{Fuel\ firing\ rate\ x\ GCV} * 100$$

ExxonMobil will demonstrate compliance with the CO_2 emission limit for the boiler using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1. Equation C-5 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 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 (74 FR 56374 October 30, 2009). 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 boilers and are considered a *de minimis* level in comparison to the CO_2 emissions.

XII. Analyzer Catalytic Oxidizers (EPN: PEXANALZ) BACT Analysis

For purposes of VOC control, ExxonMobil plans to install up to 35 analyzers containing TRACErase™ or equivalent catalytic oxidation technology distributed throughout the process equipment. The only practical option for control of VOC emissions from some of the analyzers is the proposed technology of catalytic oxidation powered by electricity. Due to the presence of oxygen in some of the analyzer vent streams, these vent streams cannot be recovered to the process or controlled in the Vent Collection System. Thermal oxidation was evaluated as an alternative method of control of hydrocarbons in some of the analyzer vent streams; however, this option was eliminated because of the greater increase in GHG emissions which would result from the use of natural gas fueled burners to supply sufficient oxidization temperature in the reaction zone. If thermal oxidizers were utilized the GHG emissions from natural gas combustion alone would be approximately 150 tpy of CO_2e. This would be a 400% increase in the GHG emissions from the thermal oxidizers. The TRACErase™ Hydrocarbon Emission Eliminator utilizes a constant heat source (catalytic converter) to allow effective oxidation of intermittent fugitive hydrocarbon emission streams as well as continuous hydrocarbon source streams from some of the analyzers. The units are designed to maintain temperatures in excess of 100 ^oF to ensure functioning of the cartridge heater and in excess of 185 ^oF ensure functioning of the catalyst cartridge. Annual preventative maintenance to replace the catalytic cartridge shall be performed.

Using the operating practices above will result in an emission limit for the analyzer catalytic oxidizers of 28 tpy CO_2e. ExxonMobil will demonstrate compliance with the CO_2 emission limit using the estimated gas flow through each analyzer, vapor density, vapor speciation, and a 98% destruction efficiency. The equation for estimating CO_2 emissions is as follows:

$$CO_2 = \frac{QV}{MV} * DRE * 2 * MW_{CO2} * 1/2000$$

Where:

CO_2 = Annual CO_2 mass emissions from analyzer catalytic oxidizers (short tons)
QV = Total Analyzer gas volume flow (lb/hr).
MV = Molecular weight of gas (lb/lb mole).
DRE = Destruction efficiency of analyzer catalytic oxidizers (%).
MW_{CO2} = Molecular weight of CO_2 (lb/lb mole).
1/2,000 = Conversion from pounds to short tons.
2 = Mole conversion from ethylene to carbon dioxide.

XIII. Equipment Component Fugitives (EPN: PEXFUGEM) BACT Analysis

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 lines containing natural gas and lines not in VOC service, but containing methane 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. Natural gas is 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.[6] 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 and/or components can hiss when leaking, as-observed olfactory observation is a very effective method for identifying fugitive 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 MBPP 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 natural gas and fugitive emission of methane from process lines not in VOC service, but containing methane 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 components in the service of natural gas and components not in VOC service, but containing

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

methane, EPA is proposing that ExxonMobil incorporate as-observed AVO as BACT for the piping components associated with this project in natural gas and fugitive emission of methane from process lines not in VOC service, but containing methane. 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) and a quarterly connector monitoring program (equivalent to the TCEQ 28LAER) for fugitive emissions control in the New Source Review (NSR) permit No. 103048 to be issued by TCEQ. EPA concurs with ExxonMobil's assessment that using the TCEQ 28VHP[7] 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 fugitive sources, and although the existing LDAR program is being imposed in this instance, it is imposed as a work practice. See 40 CFR § 51.166(b)(12) (technological and economic limitations make measurement methodology infeasible under the circumstances here).

XIV. Endangered Species Act (ESA)

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 eleven (11) species listed as federally endangered or threatened in Chambers and Liberty Counties, Texas:

[7] The boilerplate special conditions for the TCEQ 28VHP 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.

Federally Listed Species for Chambers and Liberty Counties 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 Piping Plover	*Picoides borealis* *Charadrius melodus*
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 eleven 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.

XV. 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 June 6, 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 an approximately 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, several historic structures including several historic-age canals, ditches, and other irrigation-related resources and a historic-age railroad grade were identified. Though irrigation and the railroad system were significant factors in the historic development of the area, none of the structures had the integrity or significance to meet the criteria for NRHP listing; therefore, none of these structures were recommended to be eligible for listing on the National Register. One historic site was identified to be potentially eligible for listing on the National Register, but it is outside the APE (greater than 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 June 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.

XVI. 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.

XVII. 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]		
3UF61A 3UF61B 3UF61C	3UF61A 3UF61B 3UF61C	Flameless Thermal Oxidizers	CO_2	91,660[3]	104,413[4]	Good combustion and maintenance practices. See permit condition III.A.3.
			CH_4	5[3]		
			N_2O	1[3]		
3UFLARE62	3UFLARE62	Assisted Elevated Flare	CO_2	6,304		Good combustion and maintenance practices. See permit conditions III.A.4.
			CH_4	3		
			N_2O	2		
3UFLARE63	3UFLARE63	Multi-point Ground Flare	CO_2	7,735		Good combustion and maintenance practices. See permit condition III.A.2.
			CH_4	4		
			N_2O	2		
RUPK71	RUPK71	Regenerative Thermal Oxidizer	CO_2	2,221	2,552	Maintain a minimum combustion temperature as determined by initial compliance testing. See permit condition III.B.8
			CH_4	1		
			N_2O	1		
RUPK31 RUPK32	RUPK31 RUPK32	Boilers	CO_2	30,512	30,864	Maintain a minimum thermal efficiency of 77%. See permit condition III.C.5.
			CH_4	2		
			N_2O	1		
PEXANALZ	PEXANALZ	Analyzer Catalytic Oxidizers	CO_2	28	28	Use of Good Combustion Practices. See permit condition III.D.
PEXFUGEM	PEXFUGEM	Fugitive Emissions	CO_2	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Implementation of LDAR/AVO program. See permit condition III.E.
			CH_4	No Numerical Limit Established[5]		
Totals[6]			**CO_2**	**138,462**	**CO_2e 138,216**	
			CH_4	**32**		
			N_2O	**7**		

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 for the flameless thermal oxidizers (FTOs) applies to all three units combined in a vent recovery system.
4. The CO_2e TPY limit for the flameless thermal oxidizers (FTOs), Elevated Flare, and Multipoint Ground Flare applies to all units combined in the vent recovery system.
5. Fugitive process emissions from EPN PEXFUGEM are estimated to be 2 TPY CO_2, 17 TPY of CH_4, and 359 TPY CO_2e. In lieu of a numerical emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
6. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.